EXHIBIT 131

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-28

THIRD DECLARATION OF CALLAHAN MORIYASU
ON BEHALF OF
THE WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL

Background and Qualifications

1. I am currently employed as a Supervising Regulatory Analyst with the Public Counsel Unit of the Washington State Office of the Attorney General. In this role, I serve as an in-house expert on utility regulation. I have submitted testimony and written formal comments in several cases related to energy and electricity. I have a Master of Public Policy degree from the University of Southern California, as well as a Bachelor of Arts in Economics and History from Northwestern University. In addition to my formal education, I have completed several utility ratemaking courses, including New Mexico State University's Electricity Regulatory Training Course, Michigan State University's Power Grid School, and the National Association of Regulatory Utility Commissioners' (NARUC) Rate School and Fundamentals of Electricity Course.

Purpose of This Affidavit

2. This affidavit discusses estimates of resource adequacy in the Pacific Northwest in Summer 2026, indicating that the TransAlta Centralia Coal Plant is not necessary to serve load.

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The Reliance on NERC's 2026 Summer Reliability Assessment Ignores Relevant Details Not Contained in the NERC Report, Makes Inaccurate Analytical Comparisons, and Overcorrects for Relatively Low Risk

3. DOE Order No. 202-26-28 (Centralia III) relies heavily on the North American Electric Reliability Corp's (NERC) 2026 Summer Reliability Assessment (SRA). However, Centralia III ignores key assumptions and methodological decisions in NERC's SRA that would provide a more holistic picture. For example, NERC's 2026 SRA fails to consider key information about regional snowpack, uses a metric for loss of load hours (LOLH) to categorize regions with "elevated" risk that is much lower than the standardized benchmark, and the SRA methodology has changed since last year's SRA, rendering comparisons inaccurate. Even so, NERC's SRA estimates expected unserved energy (EUE) of 2.7 MWh during "extreme conditions." Ex. 131-1 at 36 (NERC 2026 SRA (May 2026)). Centralia III does not justify why Centralia's coal operations are a better response to an EUE of 2.7 MWh compared to other options. For example, while NERC's 2026 SRA includes demand response in its estimate of net internal demand, the SRA does not explain why available demand response decreased from 30 MW to 2 MW between the 2025 and 2026 SRAs. Ex. 131-1 at 8, 49. Larger demand response capability could address the 2.7 MWh EUE.

4. NERC's 2026 SRA states that the WECC-NW region has "challenging hydrological conditions," including the fact that Washington's "snow water equivalent was at 52% of normal levels as of April 1." Ex. 131-1 at 2. However, in the June 22, 2026, Washington State Resource Adequacy Meeting, sponsored by the Washington Utilities and Transportation Commission (WUTC) and Washington Department of Commerce, Washington's investor-owned electric utilities stated that the low snowpack is "partly offset by above average snowpack and reservoir levels in the Upper Columbia basin in British Columbia." Ex. 131-2 at 2 (Puget Sound Energy, *Summer 2026 Readiness: A Joint IOU Presentation* (Jun. 13, 2026)). This is even supported by the analysis of the WECC-BC in NERC's SRA, which estimates an Anticipated Reserve Margin for WECC-BC of 40.5 percent.

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Ex. 131-1 at 49. The utilities went on to state that the "hydro projections for the Pacific Northwest are above last year." *Id*. Furthermore, the NERC 2026 SRA states that the WECC-NW region has "elevated" risk. However, the NERC 2026 SRA explains that elevated risk means that "probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across the season)." Ex. 131-1 at 10. It is important to note, however, that the probabilistic index benchmark is the 1-in-10 standard. That means either 0.1 loss of load events (LOLE) per year, or alternatively, 2.4 loss of load hours (2.4 LOLH) per year. Ex. 131-3 at iii (The Brattle Group, *Resource Adequacy Requirements: Reliability and Economic Implications* (Sept. 2013)). NERC's "elevated" category, therefore, is divorced from the standardized benchmark for resource adequacy and creates an arbitrary distinction between "low" and "negligible." While such a distinction may support NERC's purpose of highlighting regional variation, it is an arbitrary measure that is not well-established by the industry, unlike the 2.4 LOLH metric. It is therefore not an appropriate basis for policy decisions or an emergency order. Additionally, the comparison of metrics between NERC's 2025 and 2026 SRAs are not valid because the 2025 SRA for WECC relied on the MAVRIC model, while in the 2026 SRA, "WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model." Ex. 120 at 4 (DOE Order No. 202-26-28 (Jun. 12, 2026)); Ex. 131-1 at 13–14 (NERC 2025 SRA (May 2025)).

Additional Research Indicates that NERC's 2025 Long-Term Reliability Assessment Makes Overly Conservative and Unrealistic Assumptions that Overstate Resource Adequacy Risk

5. Centralia III also cites NERC's 2025 Long-Term Reliability Assessment (LTRA), quoting the WECC-NW region's "high risk of energy shortfalls over the next five years," noting that the increased demand forecast was "driven by an influx of data centers into the Pacific Northwest." Ex. 106 at 7, 19 (NRC LTRA (Jan. 2026)); Ex. 120 at 4.

6. However, a report from Grid Strategies reveals deficiencies in the assumptions of the NERC report that overestimate resource adequacy risk. First, the NERC LTRA excludes

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generation resources that are nearly built, which are included in other reputable, national sources such as the EIA and LBNL. Ex. 131-5 at 5 (GridStrategies, Review of NERC's 2025 LTRA, (Jun. 22, 2026)); Ex. 131-6 at 9–13 (GridStrategies, Review of NERC's 2025 LTRA, (Mar. 5, 2026)). This contributes to an underestimate of generation capacity.

7. Additionally, the NERC LTRA omits non-firm imports, which have historically been available during periods of peak demand. Ex. 131-6 at 16. NERC also ignores the potential for new transmission additions. *Id*. at 17. Together, these two methodological choices underestimate interregional transmission and imports, and therefore overestimate resource adequacy risk.

8. Finally, Grid Strategies found that the NERC LTRA based large load projects on utility that data overstated assumptions in some cases. *Id*. at 19. NERC did not account for double counting of data centers that may enter into multiple interconnection queues, did not account for potential global supply chain issues, and importantly, did not account for the fact that many areas are starting to require large load flexibility in the form of demand response or backup generation during peak demand. *Id*.

9. As evidence of these issues related to data centers, Washington IOU Avista announced that it was pausing its processing of an energy service request from a 500 MW data center developer.[1]

10. Puget Sound Energy (PSE) has stated that it does not currently serve any data centers with demand of 20 MW or more, and that no potential large loads with pending interconnection requests have progressed beyond the exploration and study phases. Ex. 131-7 (PSE Response to WUTC Staff Data Request No. 008 (Apr. 6, 2026)).

11. While Washington has a number of data centers, the projected growth of hyperscale data centers by 2035 is concentrated in regions outside of the Pacific Northwest.[2]

[1] https://investor.avistacorp.com/news-releases/news-release-details/avista-pauses-processing-energy-service-request-500-mw-data

[2] Pacific Northwest National Laboratory, *IM3 Open Source Data Center Atlas*, https://im3.pnnl.gov/datacenter-atlas; https://www.nytimes.com/2026/06/25/realestate/where-are-the-most-data-centers-planned.html; Kelly Tyko,

12. Additionally, data center moratoriums have been emerging throughout the country, including moratoriums passed in the cities of Seattle[3] and Spokane[4], as well as the counties of Skagit[5] and Snohomish[6].

13. Additional states in WECC-NW have also implemented or proposed data center moratoriums. Oregon passed a one-year moratorium on data center tax breaks[7], Idaho passed a law imposing restrictions on data center water usage[8] and one county in Idaho restricted locations where data centers could be built to protect an Aquifer.[9] Another data center moratorium is being considered in Missoula County, Montana.[10]

E3's Resource Adequacy Study Also Overstates Resource Adequacy Concerns

14. Similarly, GridLab published a report that sheds light on the assumptions in E3's Resource Adequacy Study. Similarly to NERC's LOTR, E3's report did not consider large load flexibility. Ex. 131-8 at 4, 7 (GridLab, *Near-term winter resource adequacy challenges in the Pacific Northwest* (Jun. 22, 2026).

America's Data Center Growth Hot Spots, Mapped, Axios (Dec. 18, 2025), https://www.axios.com/2025/12/18/data-center-growth-map-states.

[3] Seattle City Council, *City Council Passes Emergency Data Center Moratorium and Policy Framework* (June 9, 2026), https://council.seattle.gov/2026/06/09/city-council-passes-emergency-data-center-moratorium-and-policy-framework/.

[4] City of Spokane, *Spokane City Council Passes One-Year Moratorium on Data Centers* (June 23, 2026), https://my.spokanecity.org/news/releases/2026/06/23/spokane-city-council-passes-one-year-moratorium-on-data-centers/.

[5] Skagit County, *Skagit County Commissioners Adopt Moratorium on New Data Centers* (June 1, 2026), https://www.skagitcounty.net/Departments/Home/press/060126.htm.

[6] Snohomish County Council, *Emergency Ordinance 26-026, Relating to Growth Management; Adopting a Moratorium on Data Centers Within Unincorporated Snohomish County; Adding New Sections to Chapter 30.28 SCC and Chapter 30.91d SCC; and Declaring an Emergency*, Legislation No. 2026-1510 (2026), https://snohomish.legistar.com/LegislationDetail.aspx?ID=8070603&GUID=06A18BDE-E669-46E1-8CA6-0887D96EFDC2&Options=ID|Text|&Search=moratorium.

[7] H.B. 4084, 83d Leg., Reg. Sess. (Or. 2026), https://olis.oregonlegislature.gov/liz/2026R1/Downloads/MeasureDocument/HB4084/Enrolled.

[8] H.B. 0895, 68 Leg., Reg. Sess. (Idaho 2026), https://www.billtrack50.com/billdetail/1989323.

[9] Kootenai County Board of Commissioners, *Resolution No. 2025-23: Data Center Building Permit Moratorium* (Mar. 11, 2025), https://www.kcgov.us/DocumentCenter/View/25322/25-Resolution---2025-23---Data-Center-Building-Permit-Moratorium.

[10] Missoula County, Data Center Interim Zoning, Missoula County Voice (2026), https://missoulacountyvoice.com/data-center-interim-zoning.

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15. Additionally, as it had not yet been announced, the E3 Phase 1 study did not include the TransAlta Centralia coal-to-gas conversion, meaning that it overstated the resource adequacy concern in the region. Ex. 131-8 at 4.

16. The GridLab study went on to model dispatch based on what would happen if an extreme weather event, such as the January 2024 cold snap, were to occur in 2030. Even using E3's relatively high assumptions of organic load growth, the GridLab study found that 3,119 MW of capacity would need to be added by 2030, rather than the 5,641 MW suggested in E3's Phase 1 results. Furthermore, depending on whether large loads come to fruition, if those large loads have flexibility, and considering the range of organic native load growth, capacity addition needs could range even lower, from 0 to 1,218 MW. *Id*. at 7. In other words, E3's findings are highly sensitive to load growth assumptions, and there is a wide range of reasonableness. E3's report is at the higher end of that range, and overstates the risk to resource adequacy.

Washington Electric IOUs Report No Major Concerns with Resource Adequacy for the Summer

17. Furthermore, all of Washington's Electric IOUs stated, at the WUTC's June 22, 2026, Resource Adequacy Meeting, that they have adequate capacity for summer 2026.

18. PSE stated that it has the resources to "meet our WRAP capacity targets," added 250 MW of capacity since last year, and increased its demand response programs to 61 MW. Ex. 131-2 at 3.

19. Avista stated that it is "currently resource adequate for summer 2026 plus PRM." *Id*. at 6.

20. PacifiCorp stated that it has added 920 MW in battery storage since last summer and completed the Naughton 1&2 gas conversion, allowing for 375 MW contribution to its system. Furthermore, PacifiCorp's participation in the Extended Day Ahead Market (EDAM) is now live, allowing for the "full breadth of [the] market to support operations." *Id*. at 8.

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Centralia Was Not Called Upon to Operate During the 90 Day Period of the Second Emergency Order

21. During the 90-day period of the second emergency order, Centralia was never called on to operate, demonstrating that it was not needed to serve load.[11]

DATED this 9 day of July 2026, in Seattle, Washington.

Callahan Moriyasu

CALLAHAN MORIYASU

[11] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/GRID?utm_source=chatgpt.com

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EXHIBIT 131-1

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

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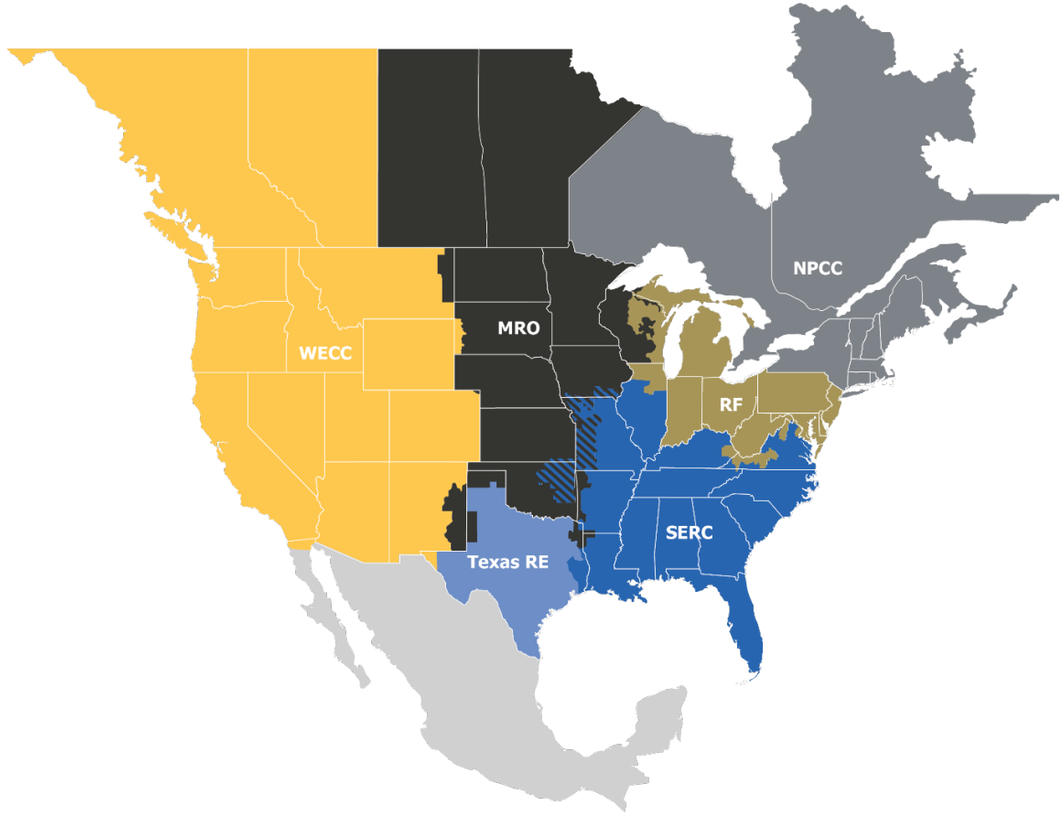
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

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



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

About This Assessment

NERC's *2026 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2026.

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

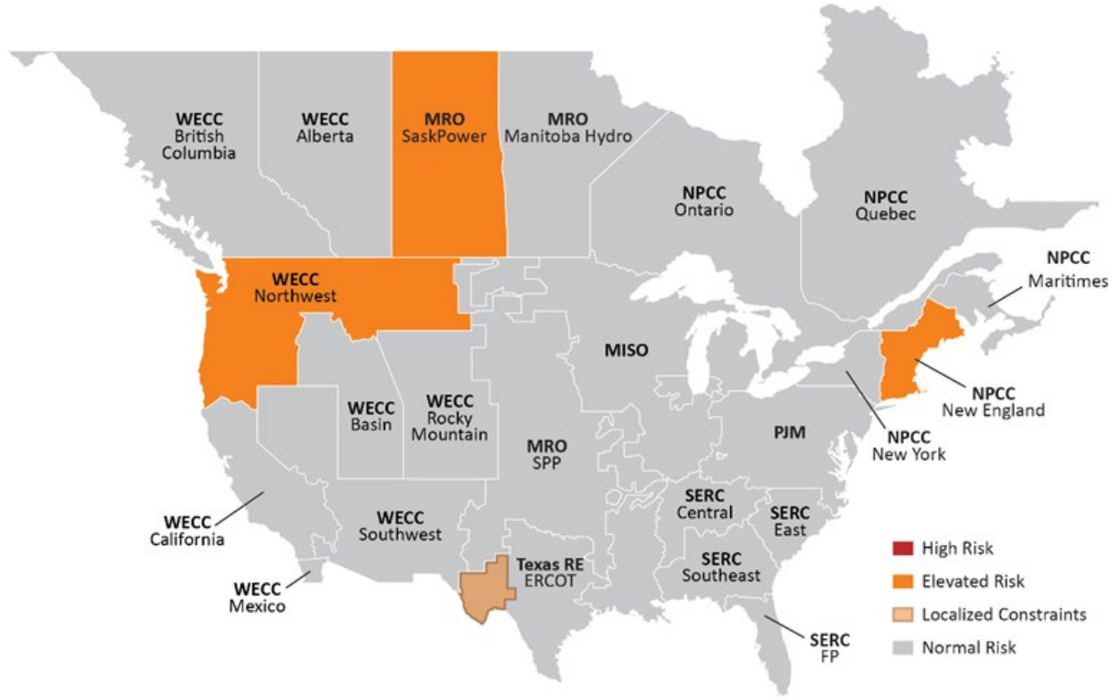
Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or are subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalaches substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the *2025 SRA* of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the *2025 SRA*, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,[2] when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the *2025 SRA* and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

[2] WSOR-WA

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**[3] El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see **Figure 2**). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,[4] starting with sub-average snowpack[5] heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The **Review of 2025 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2025 SRA* and summarizes 2025 resource adequacy events.

- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out 23 assessment areas saw demand increases from the *2025 SRA* projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.[6] The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC issued a Level 3 essential actions alert related to large loads[7] as well as a reliability guideline regarding risk mitigation for emerging large loads.[8]

- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.[9] Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

[3] Climate Prediction Center: ENSO Diagnostic Discussion
[4] Climate Prediction Center: Seasonal Drought Outlook
[5] WSOR-WA
[6] *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, NERC, January 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf
[7] NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control
[8] Risk Mitigation for Emerging Large Loads
[9] NERC State of Reliability reports

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.[10] The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.[11] Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.
- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.[12]

[10] Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information (NCEI)
[11] Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network
[12] *Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps*, https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) in the elevated-risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of above-normal demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[13]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
  - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
  - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
  - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.[14]

[13] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

[14] See Incident Review section of NERC Event Analysis page.

Risk Highlights

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

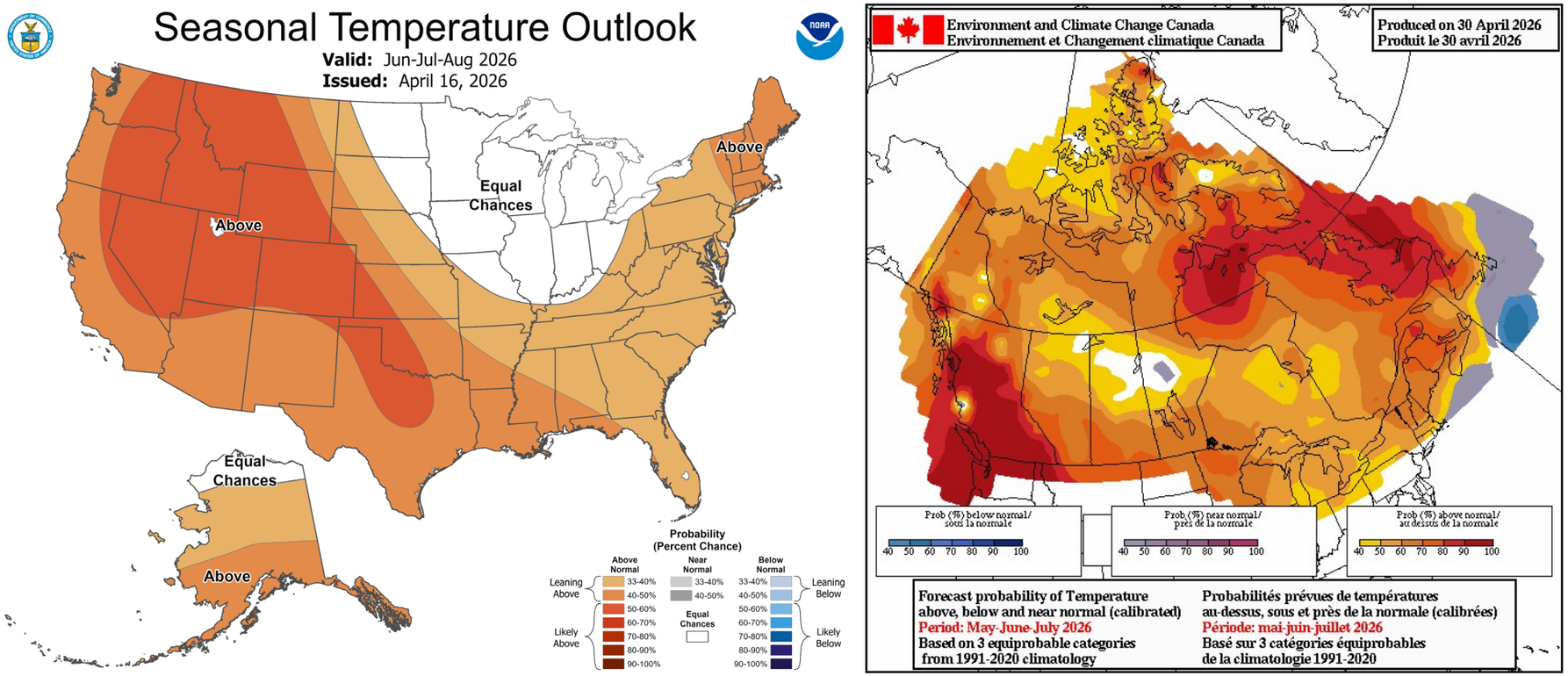


Figure 2: United States and Canada Summer Temperature Outlook[15]

[15] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see **Figure 3**). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

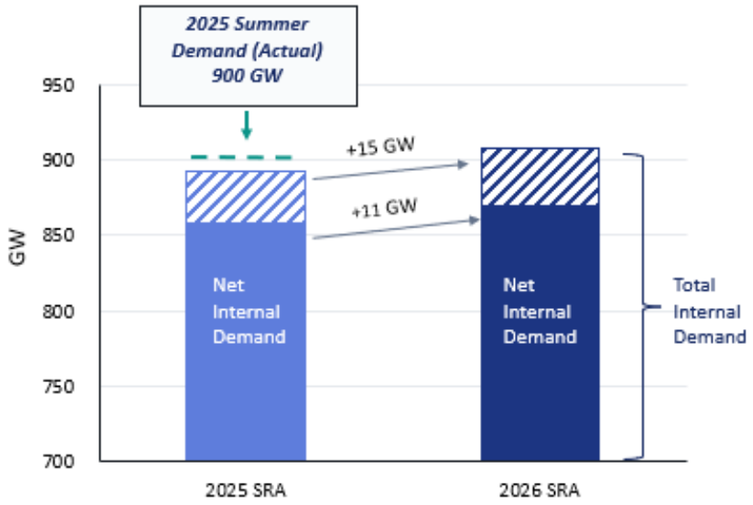


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the **Net Internal Demand** section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see **Figure 4**). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

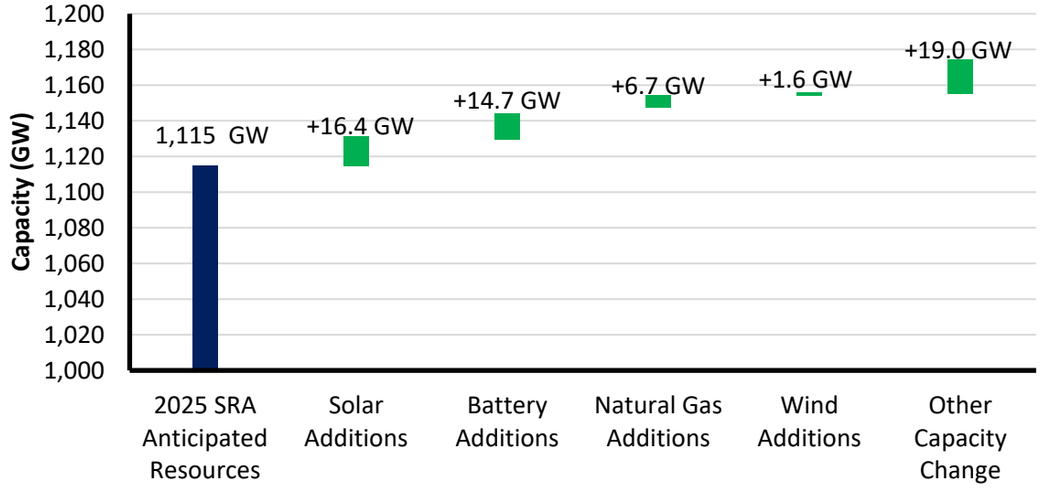


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see **Table 1**). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 2**.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2 hours or higher across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **normal resource scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with **normal resource scenarios**[2] (i.e., typical or expected outage and derate scenarios for conditions) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **reduced resource scenarios**[3] (i.e., extreme outage and derate scenarios)
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible (e.g., LOLH below 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1] The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the peak demand.
[3] **Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4] Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 3**.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each

dashboard provide potential summer peak demand and resource condition information, as well as risk hour resource condition information for areas where the risk hour differs from the peak demand hour. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be on maintenance or forced outage during peak demand conditions. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's summer risk scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 4**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2026. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

EEA Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 MWH/year for the Reference Margin Level. Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results[16] of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

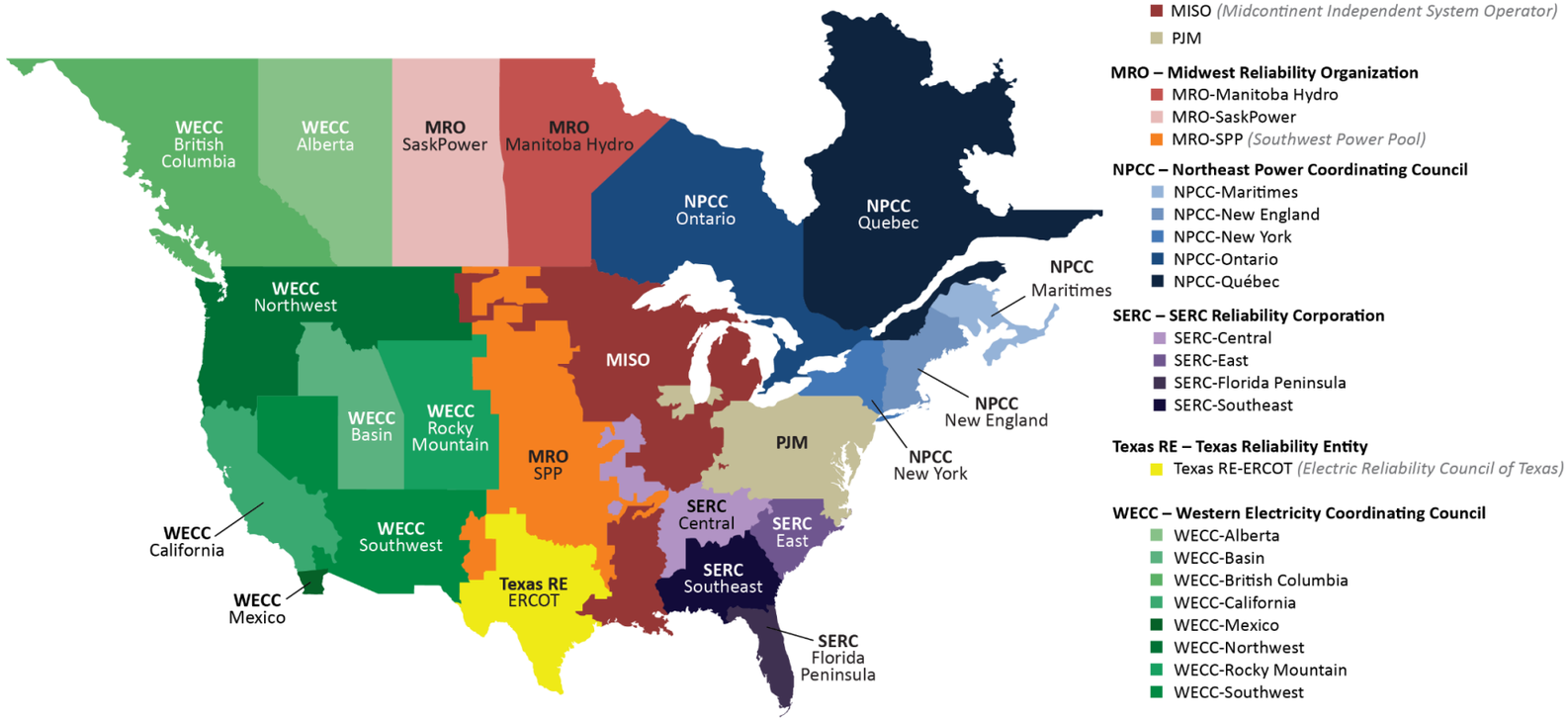
[16] Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. This is categorized by ERCOT as "low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2025 SRA*, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC–Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables** section), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables** section) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

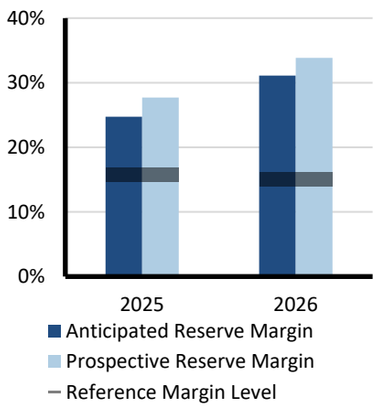
Highlights

- Although MISO's peak load has increased by 2.5 GW from the *2025 SRA*, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

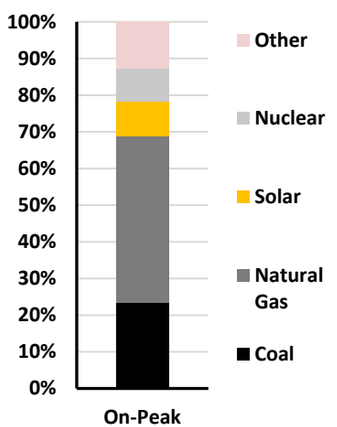
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

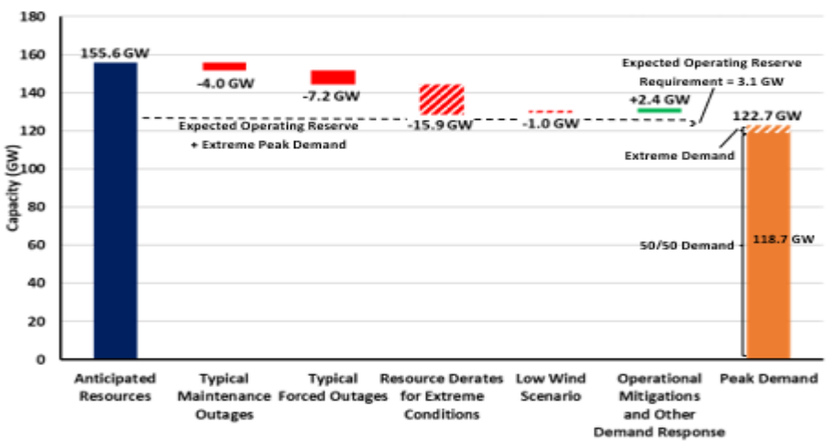
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June–September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme conditions.



MRO-Manitoba Hydro

Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

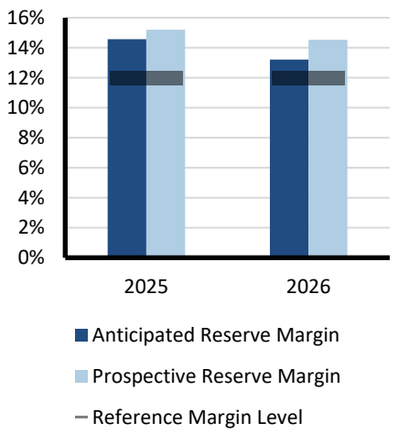
Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

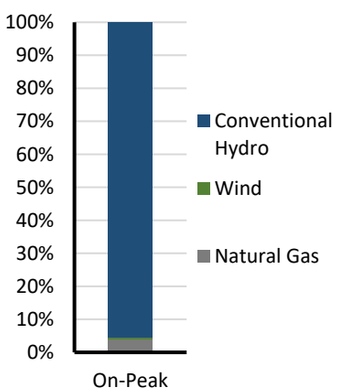
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

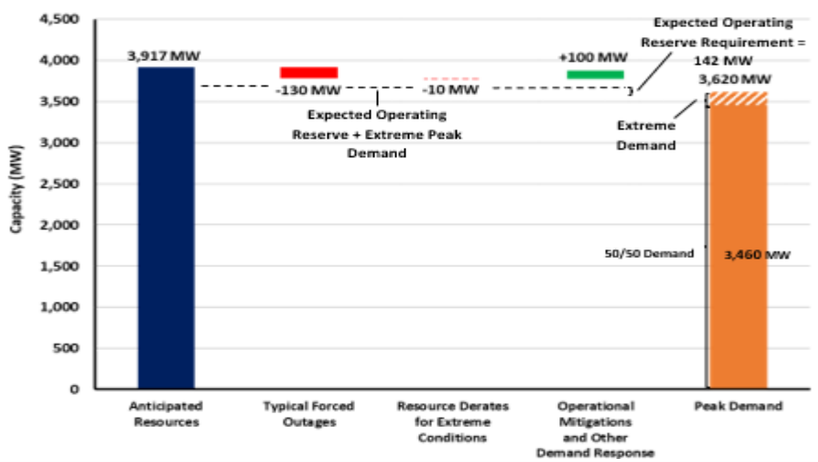
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: 50/50 Demand with allowance for extreme demand based on a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.



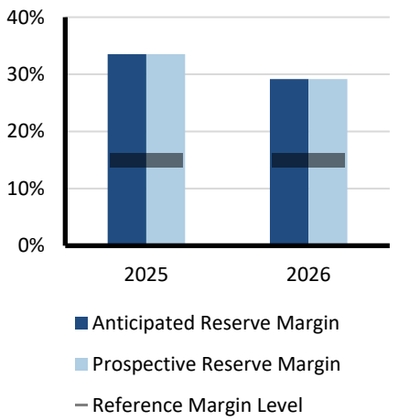
MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the *2025 SRA* projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

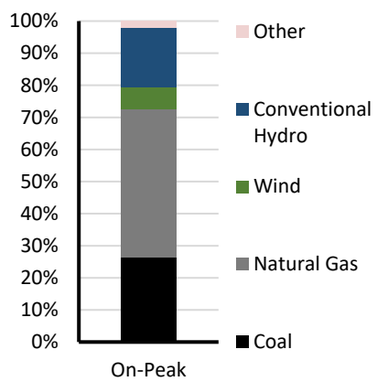
On-Peak Reserve Margin



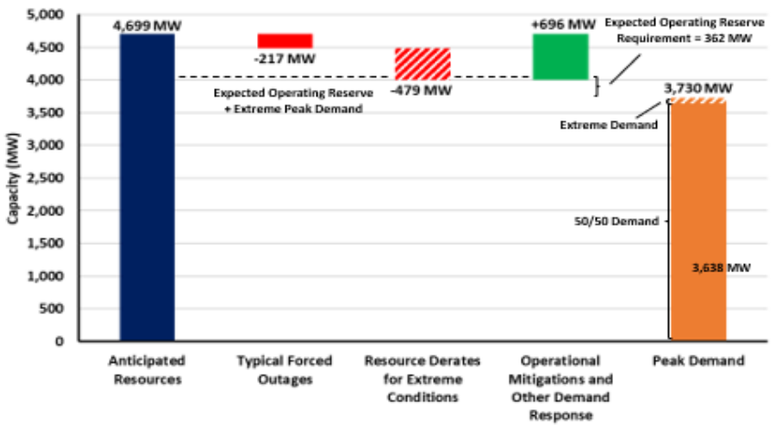
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads.

Forced Outages: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.



MRO-SPP

The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

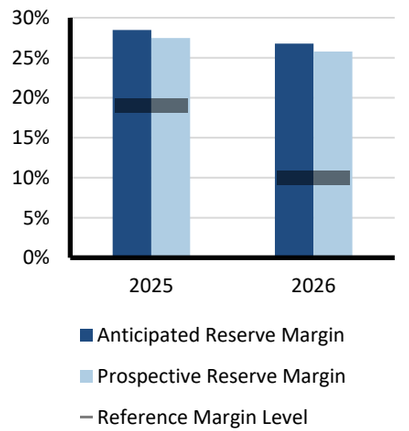
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

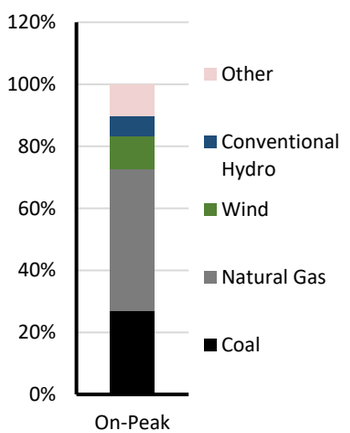
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

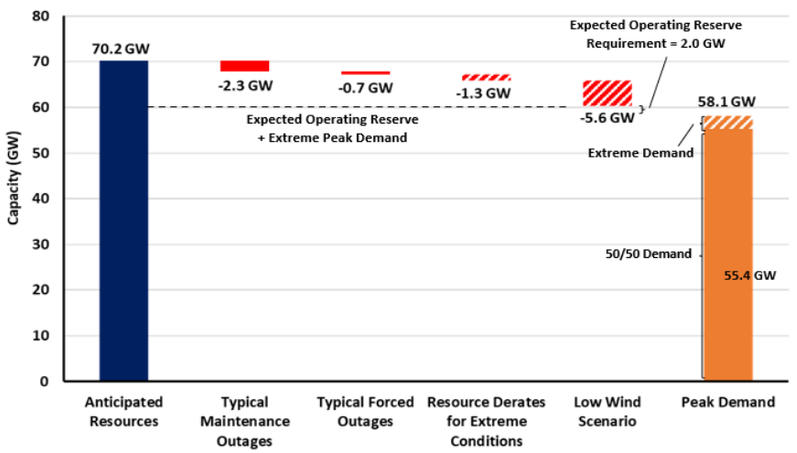
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 4.9% increase from net internal demand.

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process.

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods.

Low Wind Scenario: Derates reflecting an average low-wind day in the summer.



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

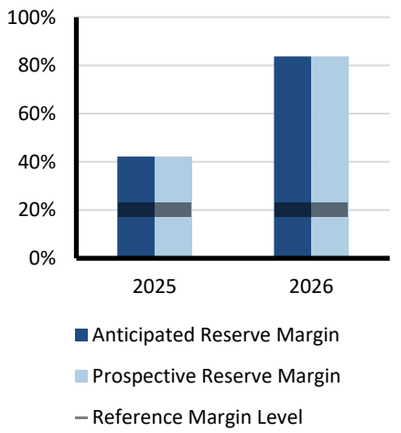
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

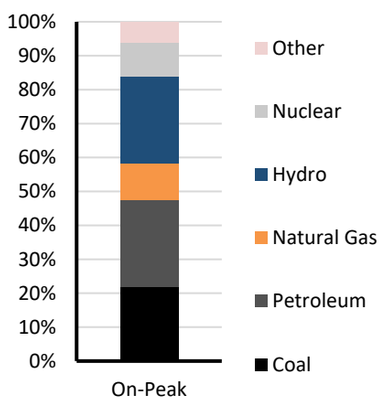
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

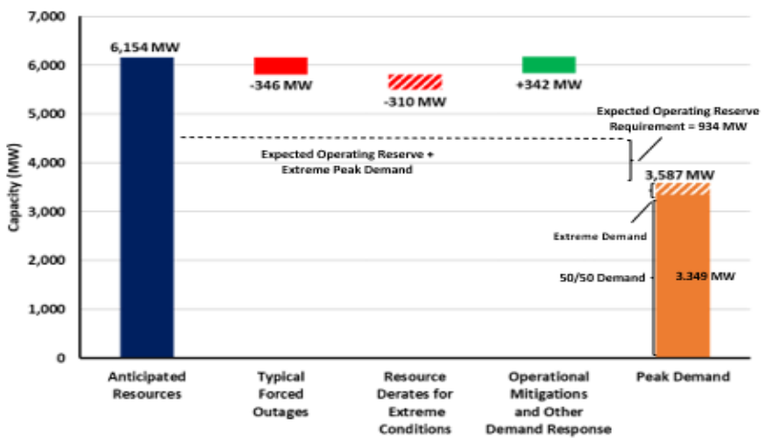
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above 90/10 extreme demand forecast.

Forced Outages: Based on historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.



NPCC-New England

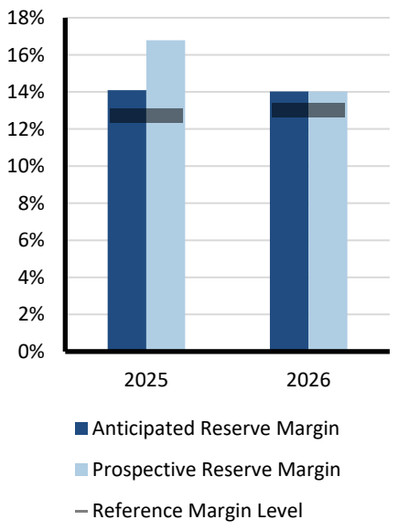
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

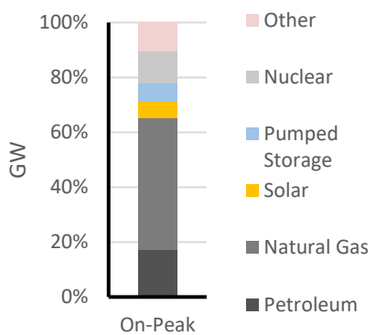
On-Peak Reserve Margin



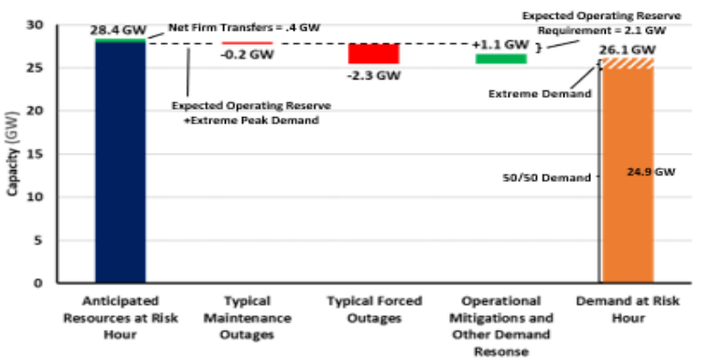
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures.



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2026–2027 IRM at 24.5%.

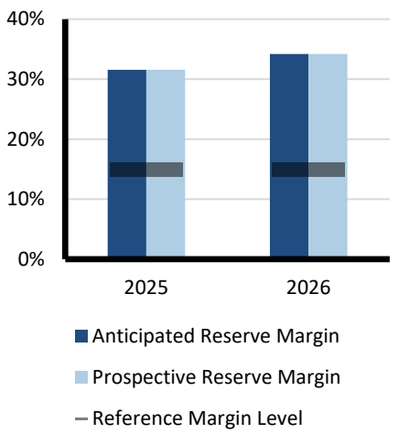
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

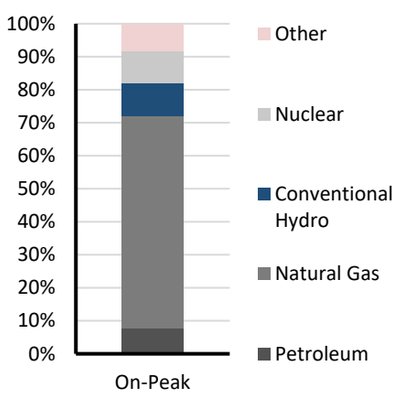
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

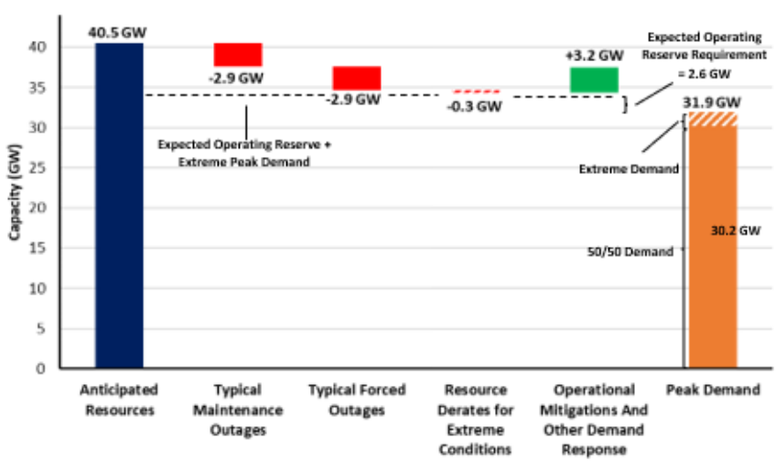
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast. **Maintenance Outages:** Based on historical performance and the new NYISO capacity accreditation process.

Forced Outages: Based on historical five-year averages.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual.



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

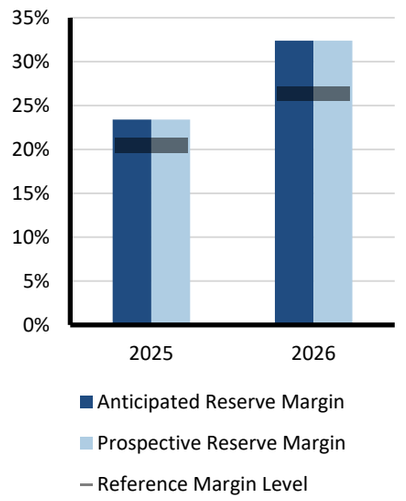
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

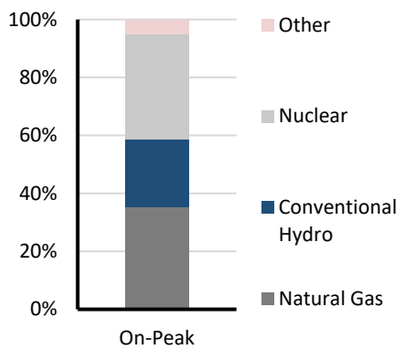
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

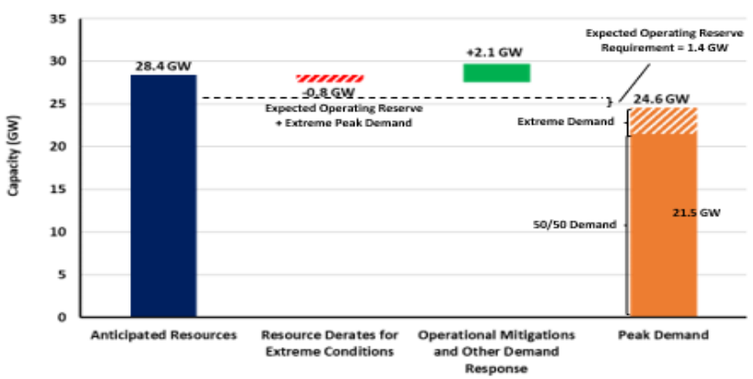
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modeled data.

Extreme Derates: Derived from weather-adjusted temperature ratings of thermal units and adjustments to expected hydro production for low water conditions.

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.



NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

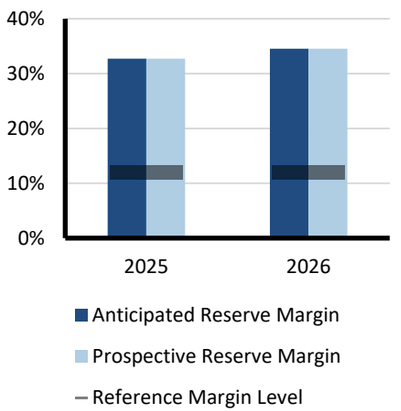
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.

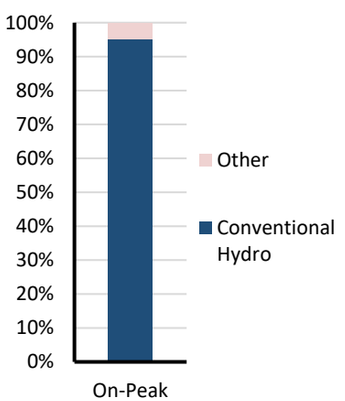
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

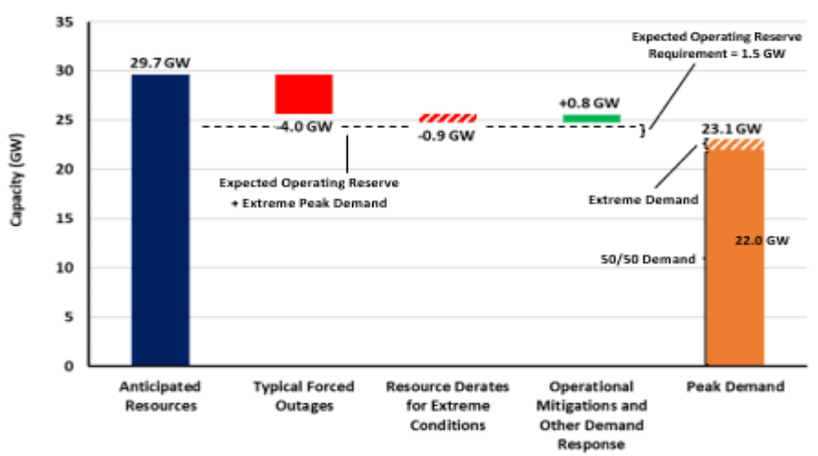
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



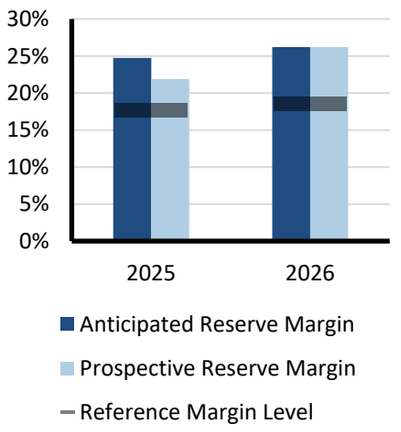
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

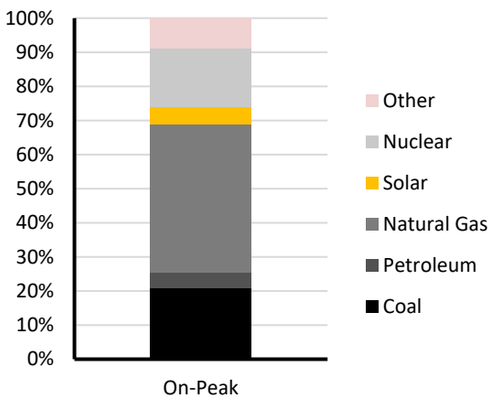
On-Peak Reserve Margin



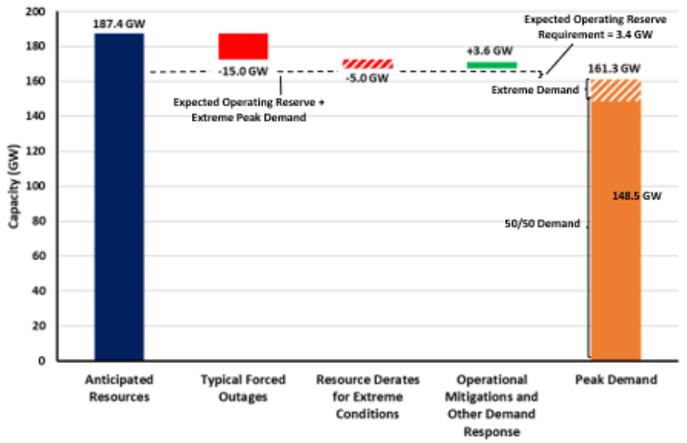
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Accounts for thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.



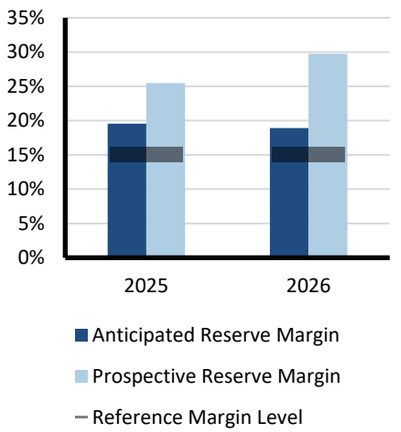
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

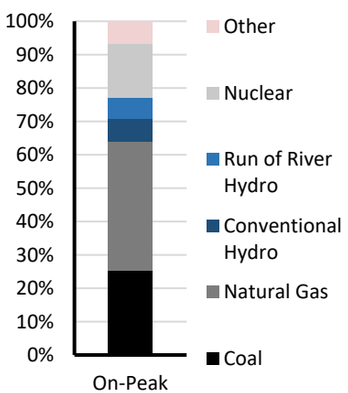
On-Peak Reserve Margin



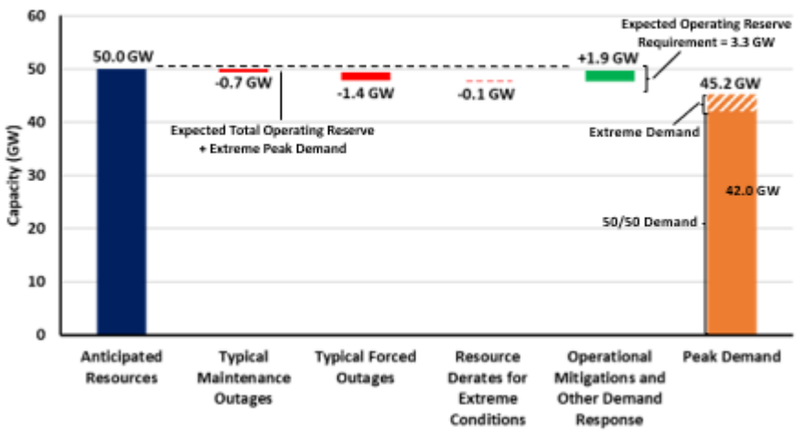
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: 1.9 GW based on operational/emergency procedures.



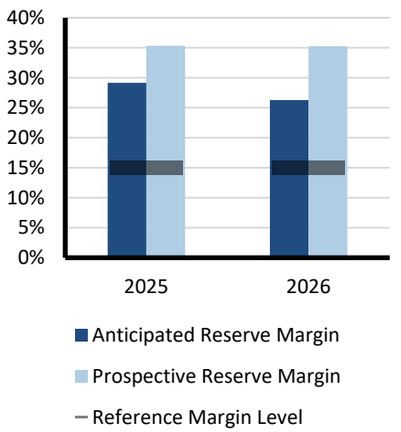
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

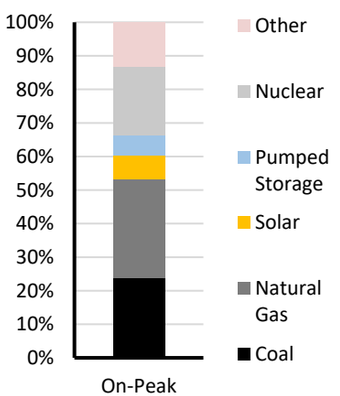
On-Peak Reserve Margin



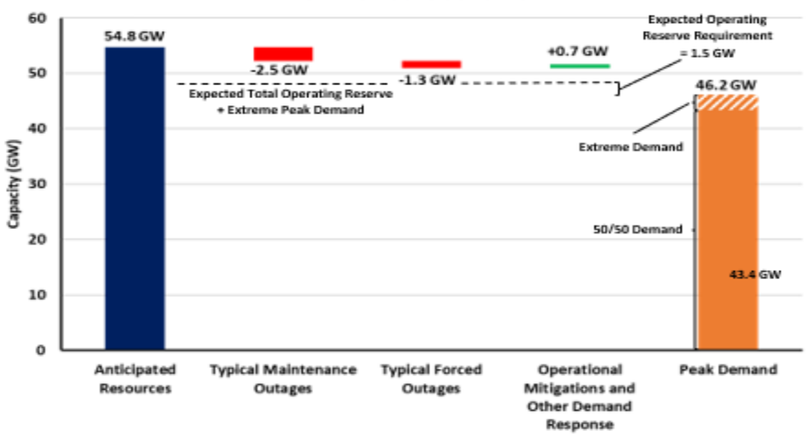
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 728 MW based on operational/emergency procedures.



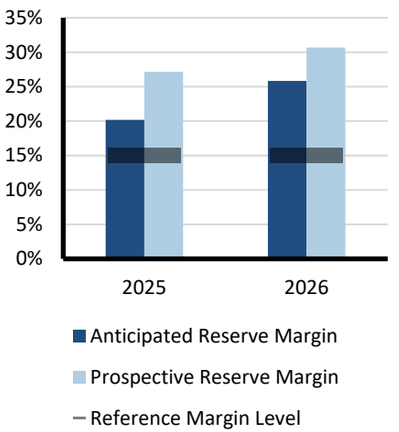
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

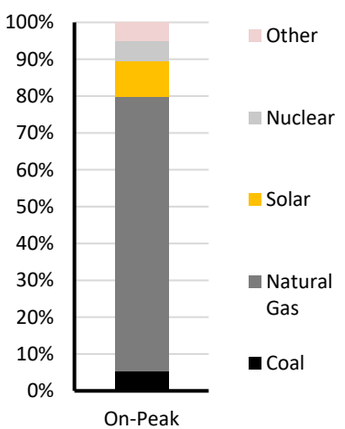
On-Peak Reserve Margin



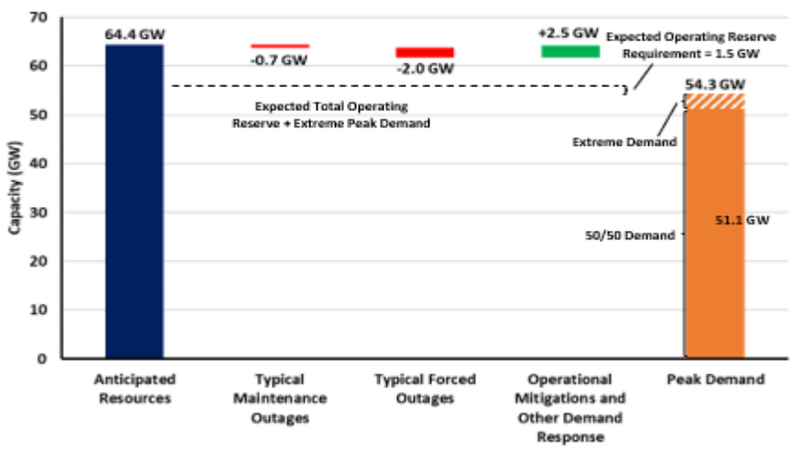
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures.



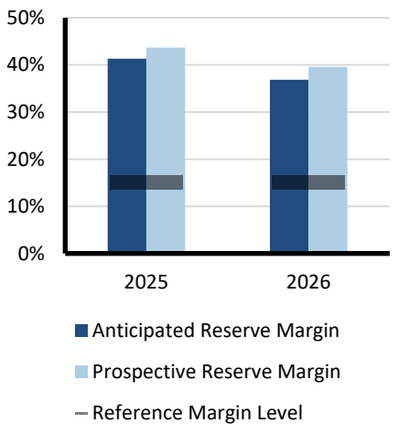
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

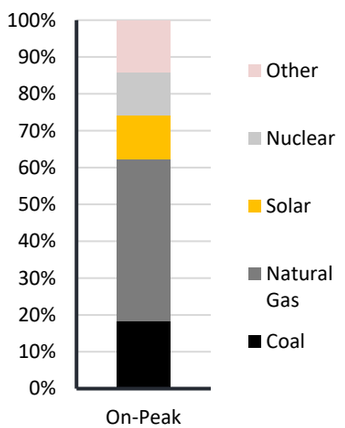
On-Peak Reserve Margin



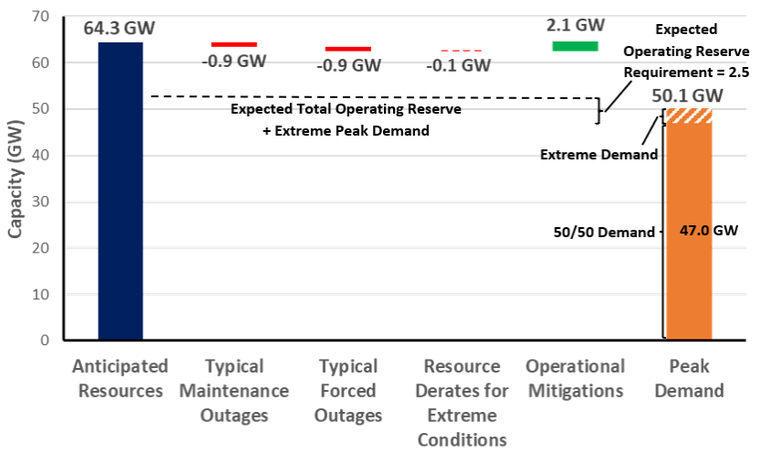
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 2.1 GW based on operational/emergency procedures.



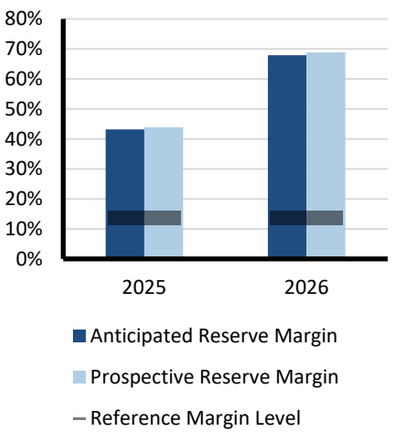
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,460 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

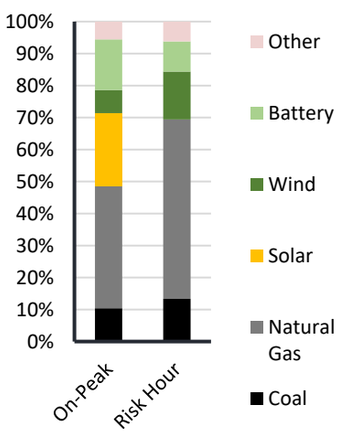
On-Peak Reserve Margin



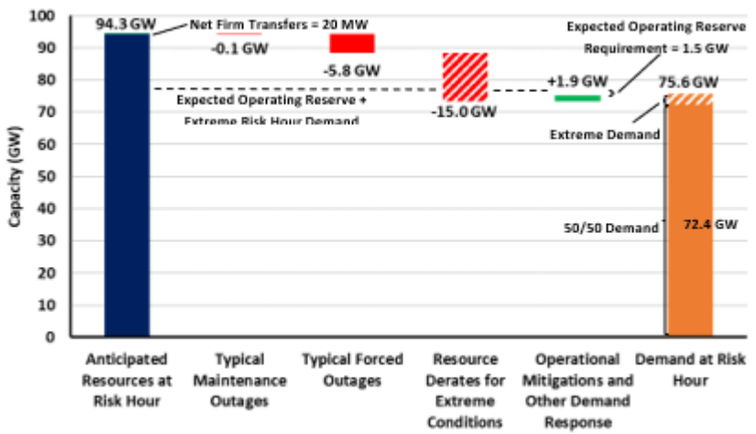
Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.



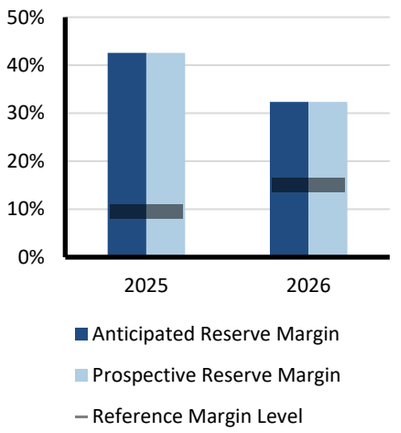
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's planning entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

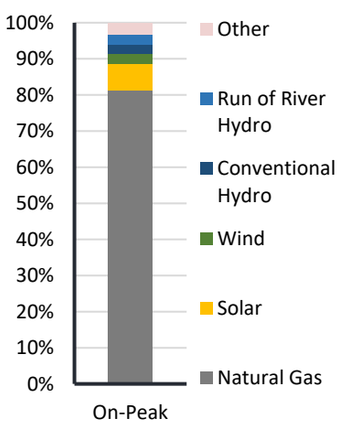
On-Peak Reserve Margin



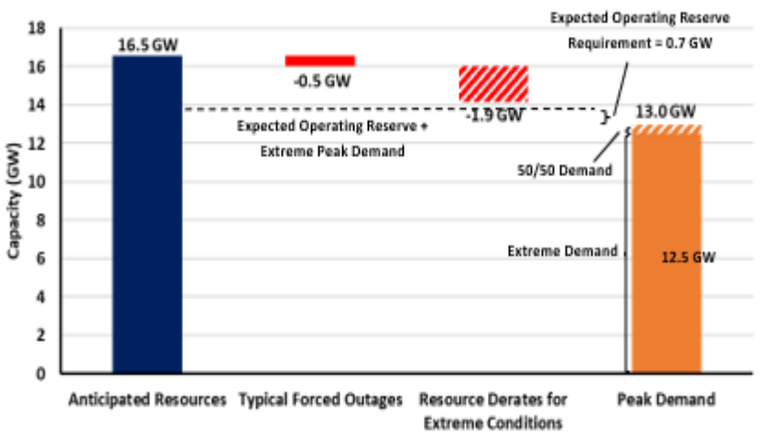
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



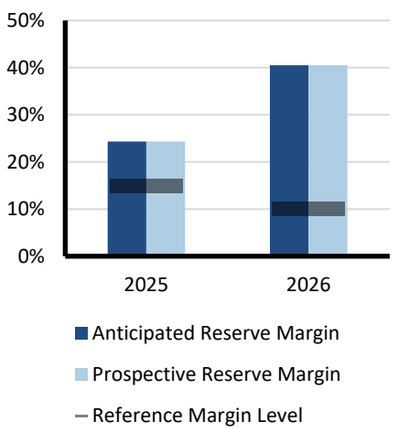
WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%

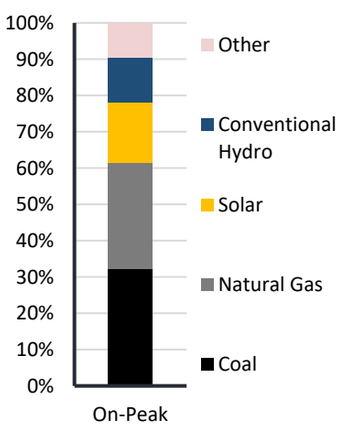
On-Peak Reserve Margin



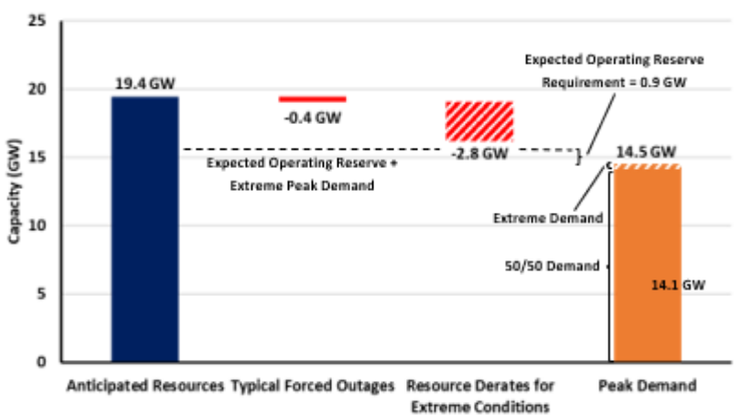
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



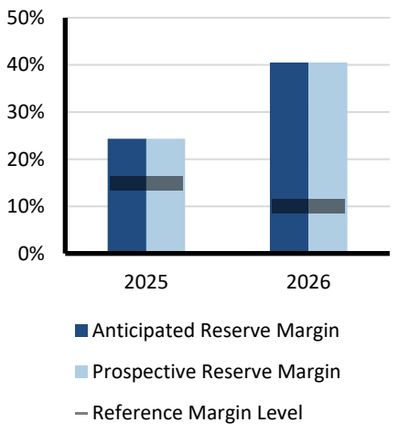
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 32 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

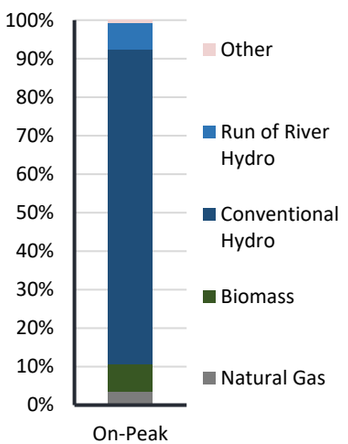
On-Peak Reserve Margin



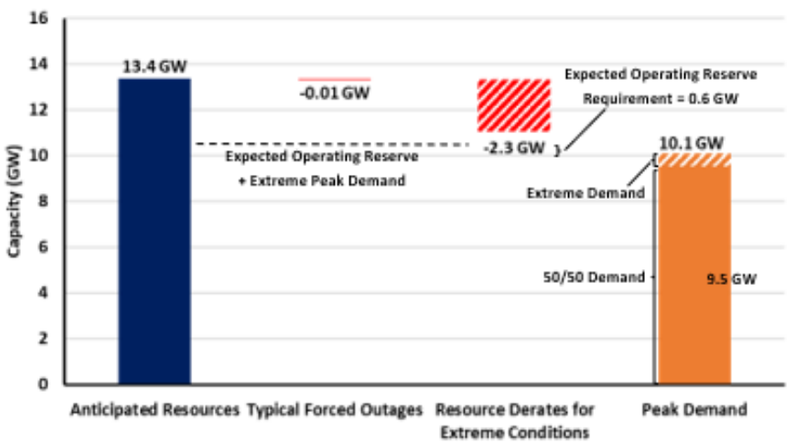
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



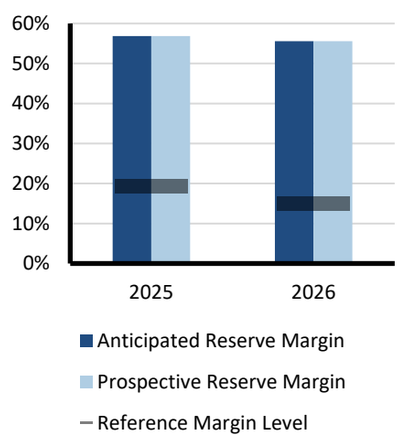
WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

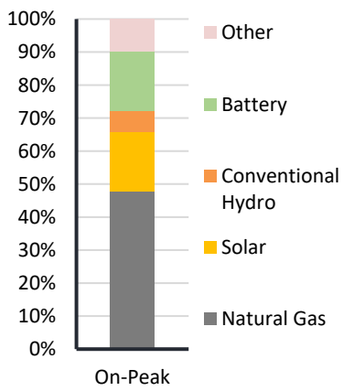
On-Peak Reserve Margin



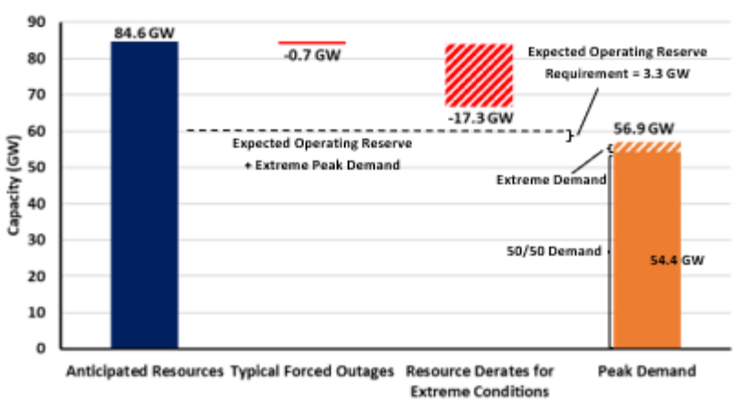
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERVM and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.



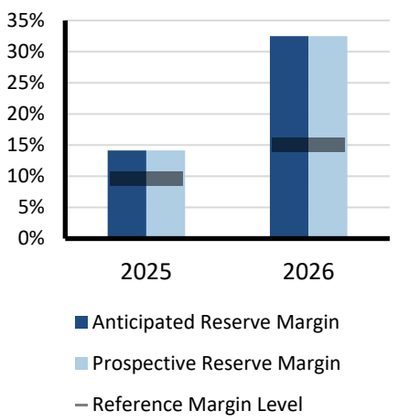
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes Centro Nacional de Control de Energía (CENACE). It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the *2025 SRA*.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

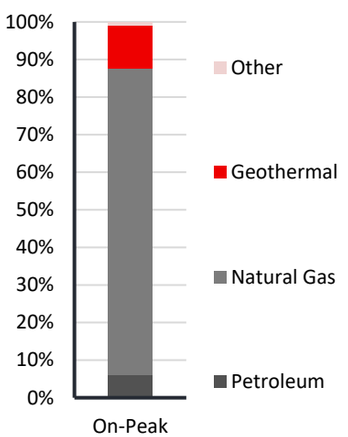
On-Peak Reserve Margin



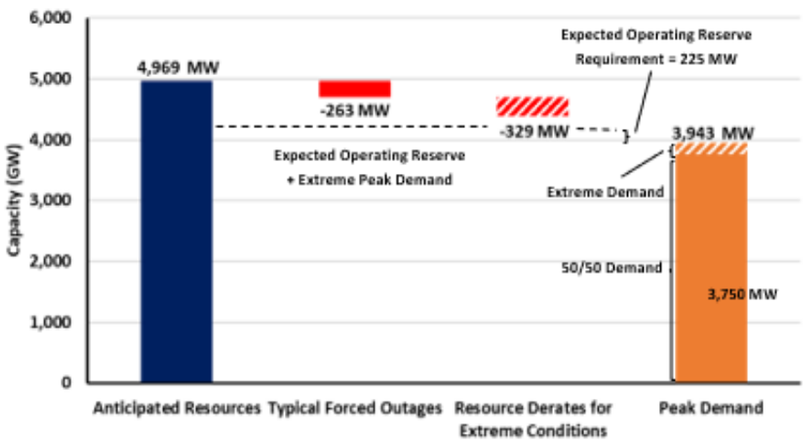
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) resource performance distribution at peak hour.



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

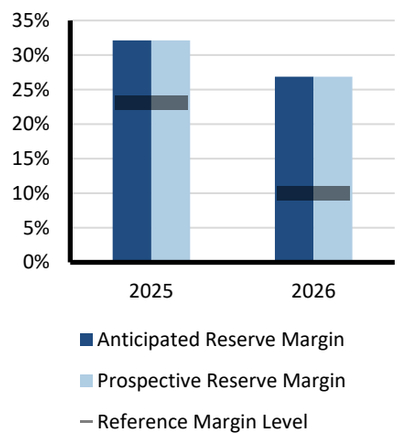
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

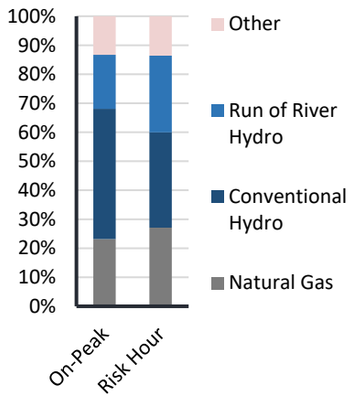
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

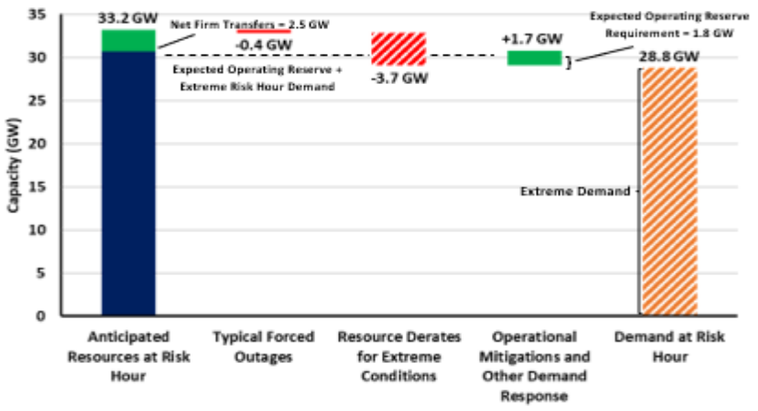
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.



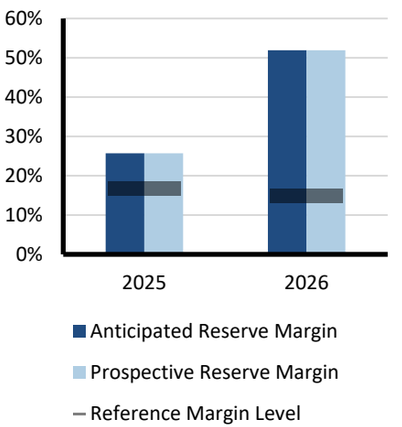
WECC-Rocky Mountain

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

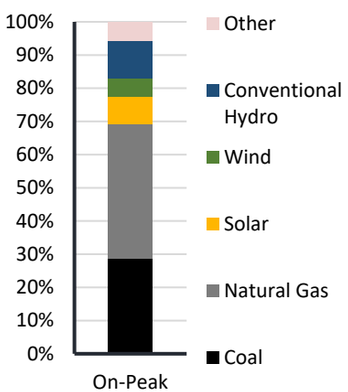
On-Peak Reserve Margin



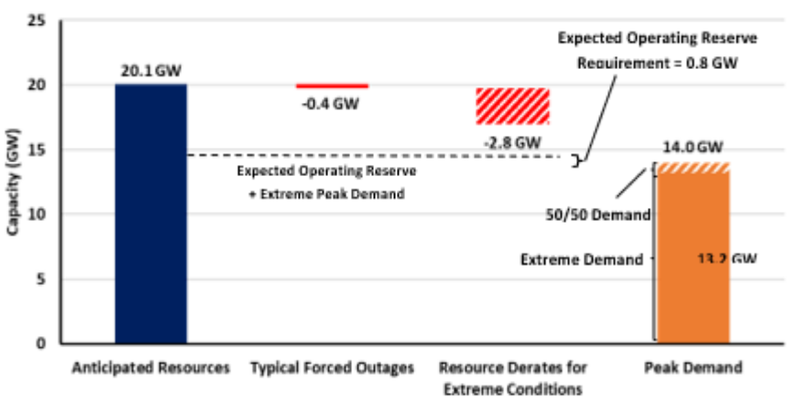
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



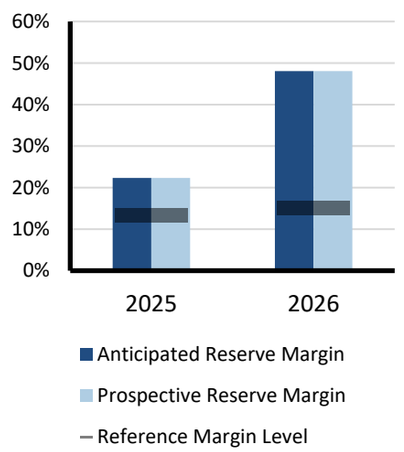
WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

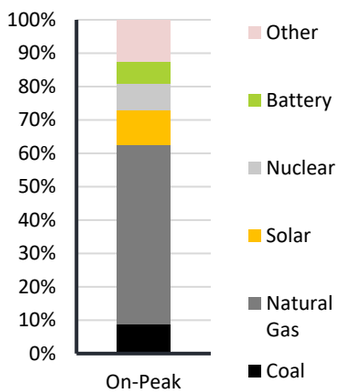
On-Peak Reserve Margin



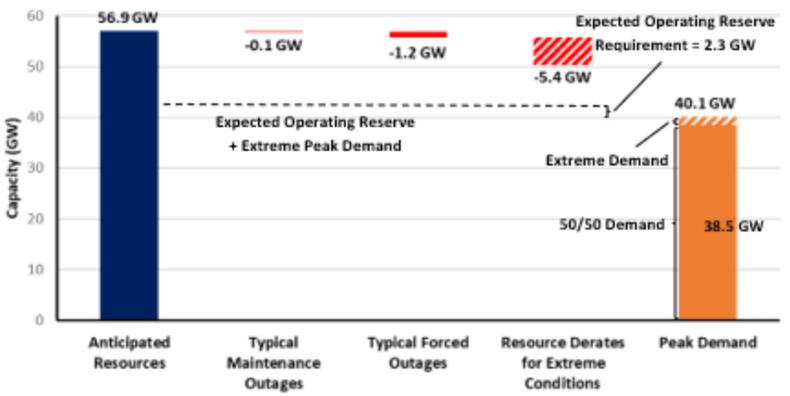
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local).

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) scenario.

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[17] or total internal demand for the summer and winter of each year.[18]
• Total internal demand projections are based on normal weather (50/50 distribution)[19] and are provided on a coincident[20] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

[17] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[18] The summer season represents June–September and the winter season represents December–February.

[19] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[20] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecast. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Level s may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[21] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in **Figure 5**.

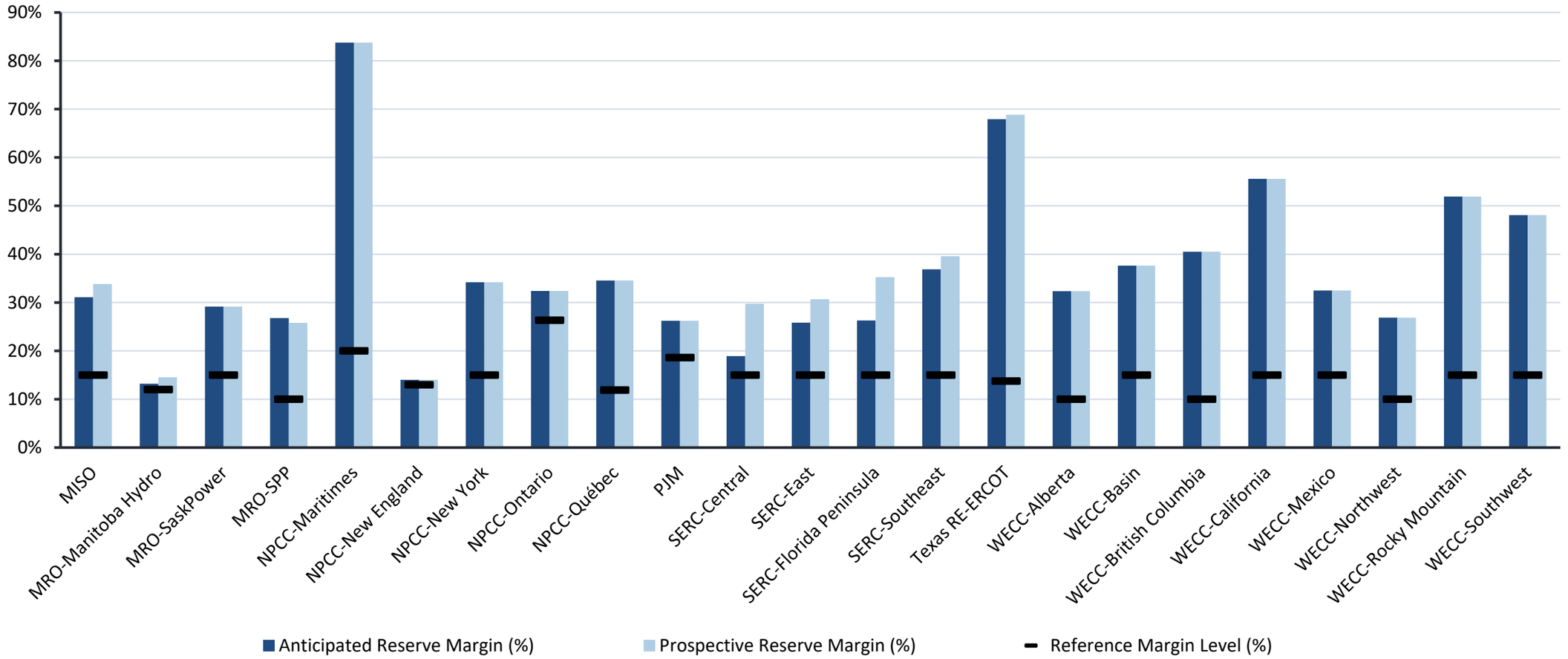


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[21] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

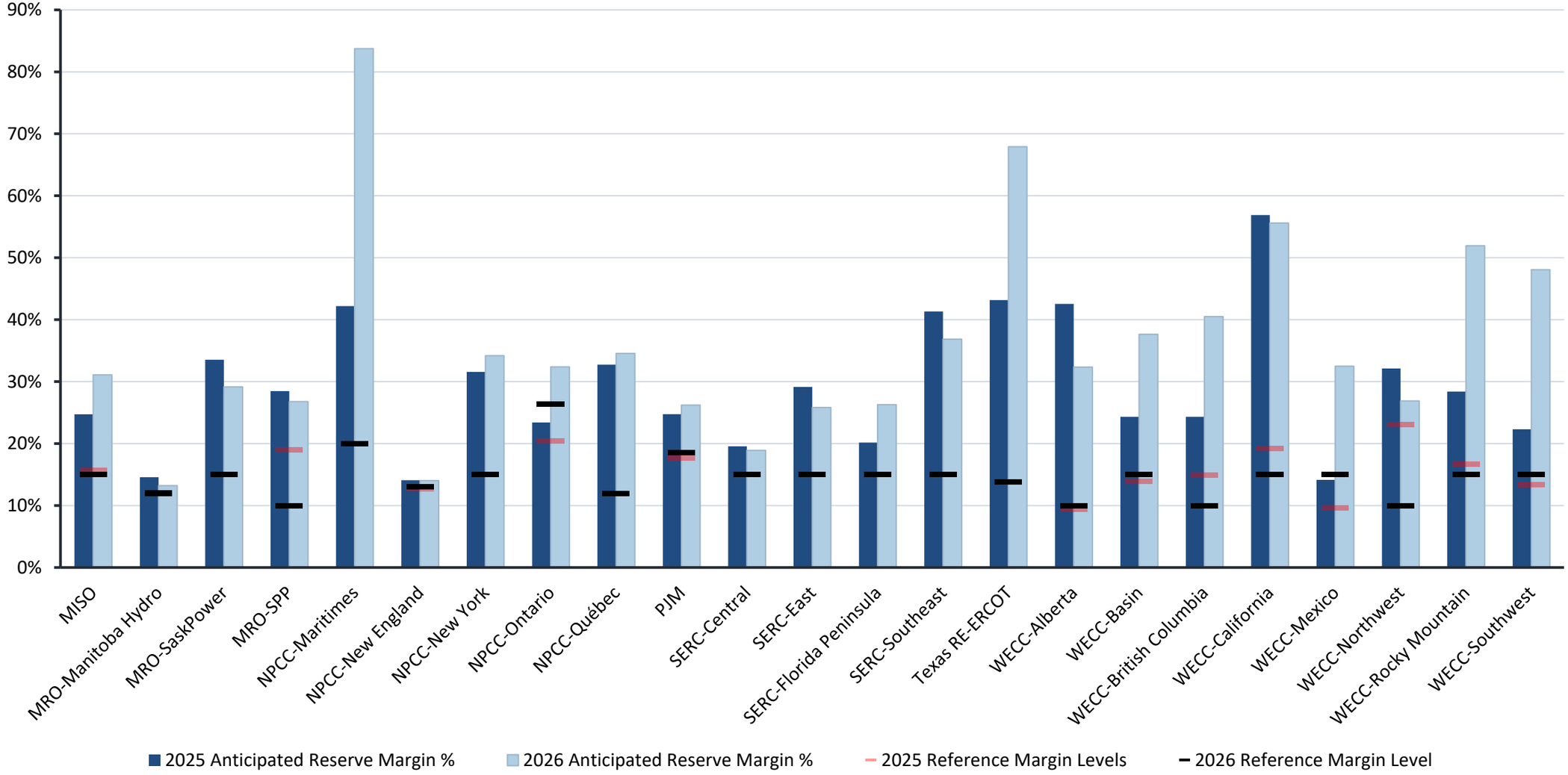


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 7**.[22] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

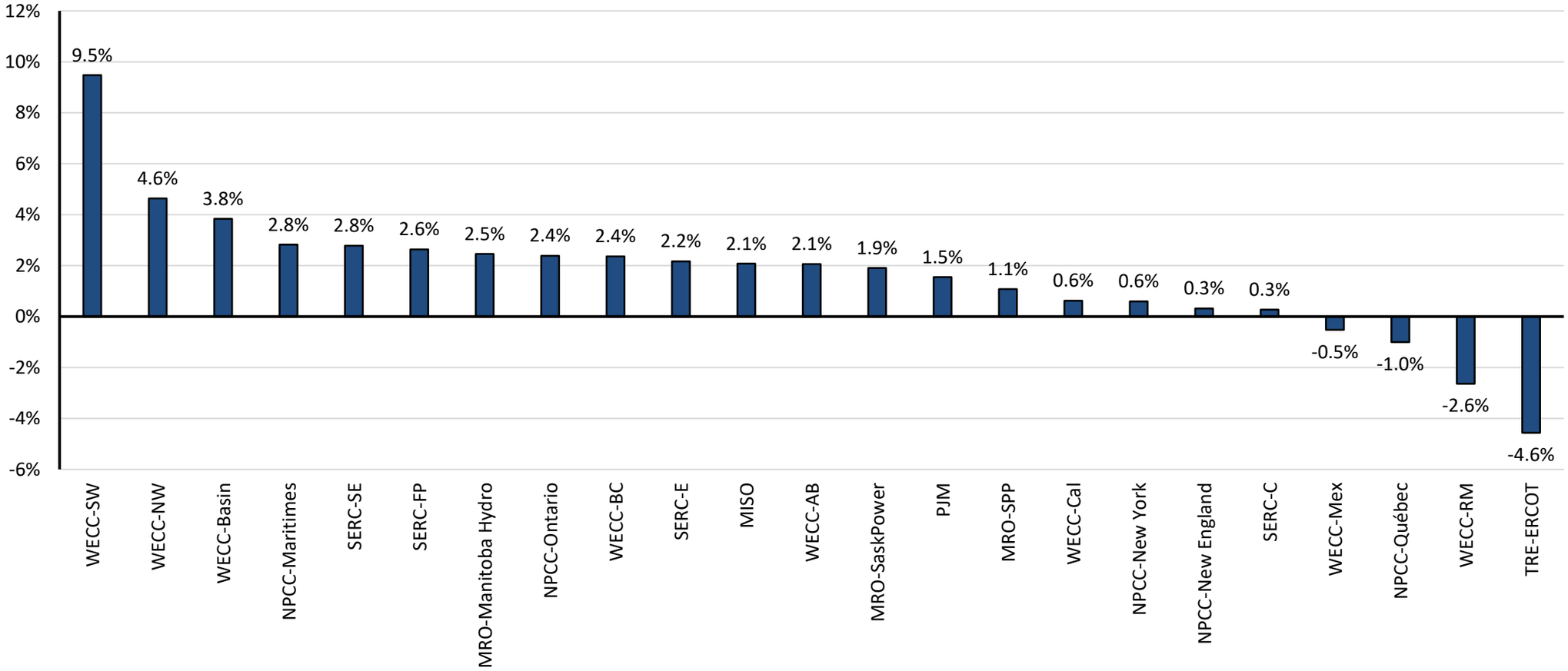


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[22] The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution (MW) of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of-River Hydro	Expected Run-of-River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION[23]	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	**181,153**	**36,673**	**20%**	**168,736**	**101,946**	**60%**	**38,822**	**26,899**	**69%**	**52,442**	**47,005**	**90%**

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

[23] Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States[24] during the meteorological summer period (June–August) and the 11th warmest summer in Canada.[25] Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], topping the prior year's summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh[29]. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave[30] in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record[31] (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,[32] culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,[33] down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.[34] The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.[35]

[24] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)
[25] Climate Trends and Variations Bulletin - summer 2025 - Canada.ca
[26] U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration
[27] Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca
[28] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[29] Electric power generation, monthly generation by type of electricity
[30] Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information (NCEI)
[31] Canada's top 10 weather stories of 2025 - Canada.ca
[32] 2025 Year in Review
[33] Electric power generation, monthly generation by type of electricity
[34] Hydro-Québec - Quarterly Bulletin - Third Quarter 2025
[35] SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the *2024 SRA*, a significant step up from the prior year's summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,[36] though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,[37] resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak[38] of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1[39] on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable[40] during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.[41] Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year's summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

[36] Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire
[37] NYISO Summer 2025
[38] 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines
[39] Microsoft PowerPoint - IMM Quarterly Report, Summer 2025
[40] DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive
[41] 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2[5] 91.3[5]	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-MX	3.5	3.8 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.
[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2025 SRA*.
[4] Values from NERC Generator Availability Data System for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.
**Data unavailable - Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

EXHIBIT 131-2

Summer 2026 Readiness:

A Joint IOU Presentation

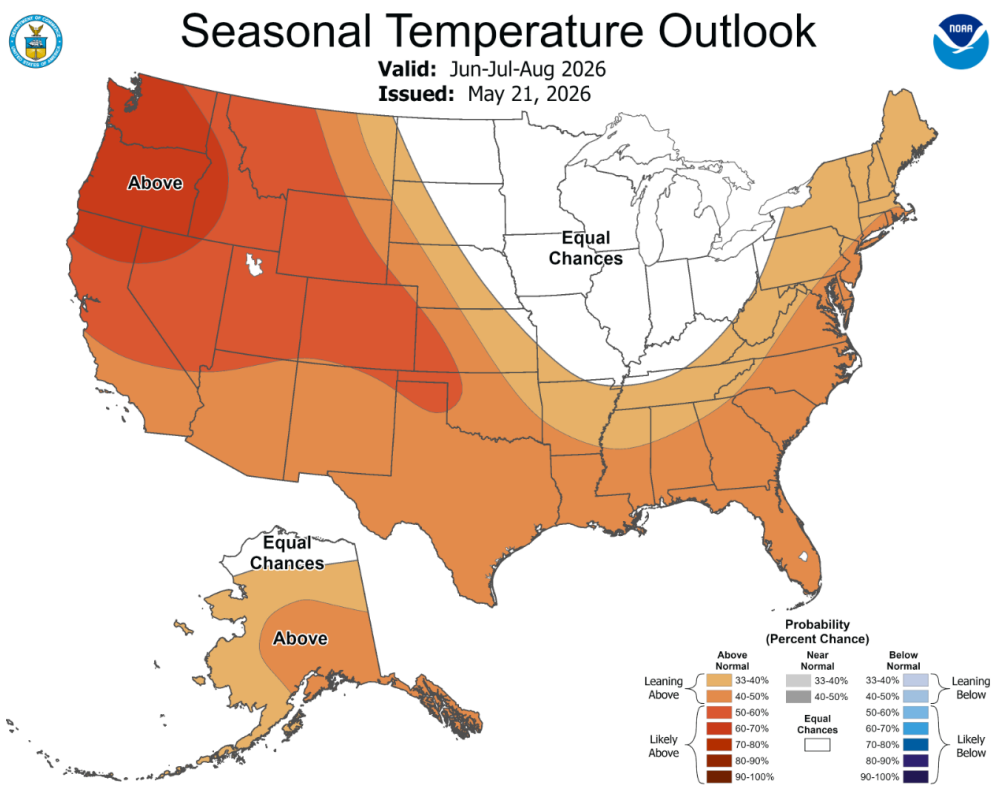
Phil Haines, *Director Energy Supply, Puget Sound Energy*

Kevin Holland, *Director of Energy Supply, Avista*

Benjamin Faulkinberry, *Senior Power Marketer, PacifiCorp*

Pacific Northwest Summer Outlook

- El Niño conditions increase the chances of above normal summer temperatures in the West
  - West-wide heat leading to coincident peak demand can strain the system
- Western snowpack is below normal, but this is partly offset by above average snowpack and reservoir levels in the Upper Columbia basin in British Columbia
  - Hydro projections for the Pacific Northwest are above last year
- Key western interconnect transmission paths are significant drivers of summer reliability
  - These paths are susceptible to derates and outages



Summer 2026 Wholesale Planning

Summer Planning Principles

- Planned generation outages are scheduled and completed prior to peak summer demand
- Coordinate with transmission providers on outages during heat events

Capacity Outlook

- PSE has resources to meet our WRAP capacity targets
  - Diverse mix of generation, including hydro, gas fired generation, and renewables
  - Pipeline transportation from multiple supply hubs and storage
- PSE added ~250 MW of capacity year over year for summer 2026
- PSE's demand response programs increased to 61 MW

Early Risk Identification (Situational Awareness)

- Proactive daily monitoring of WECC wide system conditions including:
  - Routine meetings between PSE's meteorologist, wholesale merchant, and load office operations to review short- and long-term weather outlooks
  - Continuous monitoring of short-term demand forecasts, generation availability, transmission capability, and regional price signals

Hot Weather Management and Coordination

Energy Supply Protocols

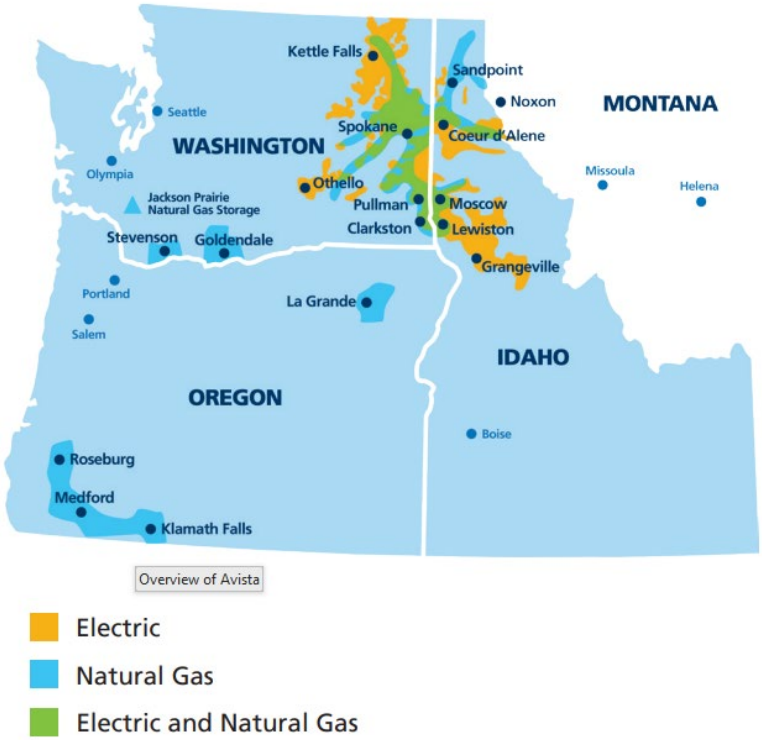
- Enhanced demand response modeling, improving dispatch to reduce PSE's peak demand
- Use of conservative short-term wind assumptions to reduce reliability risk
- Hold additional dispatchable resource capacity to account for risk to higher load and generator under performance

Enhanced Internal Communication and Coordination

- Two daily coordination calls on system conditions between real-time merchant and PSE's load office operations
  - Review system load, market conditions, and reliability requirements
- Supply conditions during elevated summer heat reported daily to senior management, load office operations, and generation
- Restricted maintenance protocols on generation assets during extreme weather events initiated by load office operations
  - Critical maintenance only

Overview of Avista

- Population of Service Area = 1.7M
- Miles of Transmission Lines = 2,800
- Miles of Distribution Lines = 19,700
- Miles of Natural Gas Distribution Main = 8,200



Resource Adequacy

- Currently resource adequate for summer 2026 plus PRM
- Broadened Transmission Portfolio
- Importance of Natural Gas

Concerns

- Unplanned outages to generation or transmission in region
- Wildfire risks to system
- Natural gas transmission/supply issues

Overview

Since Last Summer

- 920MW New Battery Storage
  - Currently in operation
  - 150MW more by 9/1
- EDAM is live (as of 5/1)
  - Full breadth of market to support operations
- Naughton 1 & 2 gas conversions complete (357MW)

Summer 2026 Outlook

- Forecasted peak: 11,492MW
  - All-time peak 11,453MW (2025)
- Extreme weather process in effect
- No fuel constraints for thermal resources
- Continuous monitoring for coincident heat / wildfire events

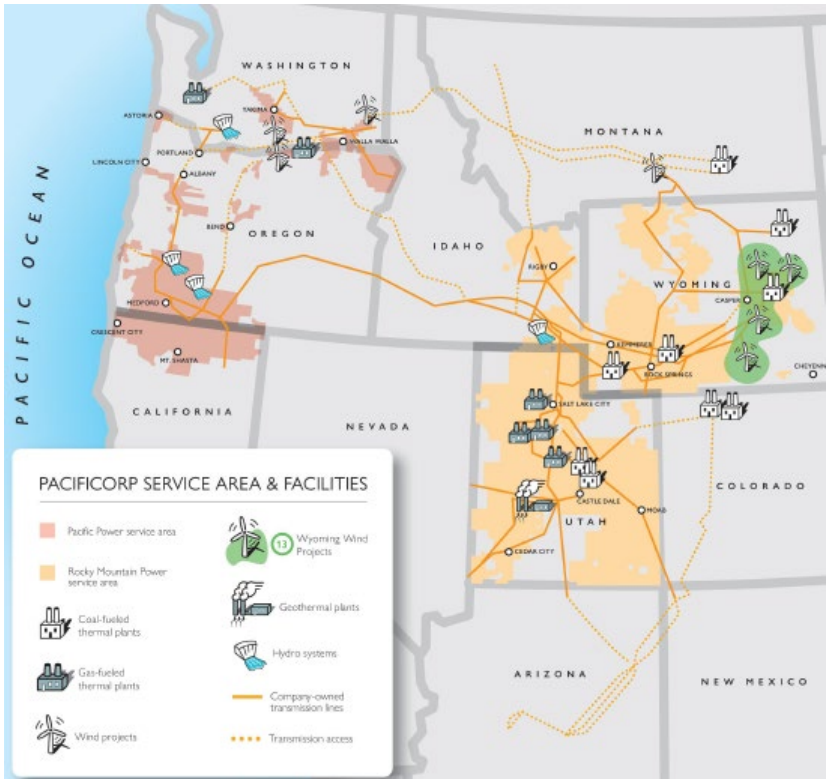


EXHIBIT 131-3

The Brattle Group

ASTRAPE CONSULTING

Resource Adequacy Requirements:
Reliability and Economic Implications

September 2013

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EXECUTIVE SUMMARY

This report, prepared for the Federal Energy Regulatory Commission (FERC), assesses the economic and reliability implications of different resource adequacy standards. We examine the widely-used one-day-in-ten-years (1-in-10) loss of load standard, compare it to alternative approaches to defining resource adequacy, and evaluate the implications of different resource adequacy standards from a customer cost, societal cost, risk mitigation, market structure, and market design perspective.

The 1-in-10 Resource Adequacy Standard

Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications. In most U.S. power systems, this standard is interpreted to mean that planning reserve margins need to be high enough that involuntary load shedding due to inadequate supply would occur only once in ten years. *One event* in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, *one day* in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard.

We survey the resource adequacy standards used in North American power markets. This survey shows that most North American systems set planning reserve margins using some variation of the 1-in-10 standard, although some set planning reserve margins based on economic considerations. Of the regions relying on the 1-in-10 standard, the majority interpret it as 0.1 LOLE. However, despite attempts to create a more uniform approach to interpreting and estimating LOLE, large differences remain in how the standard is interpreted across systems. In calculating LOLE, some systems define a reliability event as the involuntary curtailment of firm load. Other systems also consider other, less severe reliability events as contributing to LOLE, including voltage reductions or operating reserve depletions. We show that changing event definitions alone can translate to a four percentage point range in planning reserve margins. Due to these differences and its other limitations, the 0.1 LOLE standard does not represent a uniform level of reliability but instead can represent very different expected customer outage levels.

Additional differences exist in how planning reserve margins are calculated. For example, some system operators calculate reserve margins using the nameplate capacity of intermittent generation such as wind and solar, while others use a derated capacity value. Other differences exist in how voltage reductions or demand response are considered in reserve margin calculations. As we show, this means that *reported* planning reserve margins can differ by five percentage points based solely on supply and demand accounting conventions. Overall, these differences make it very challenging to meaningfully compare reported reserve margins across regions.

Simulating the Reliability and Economic Implications of Planning Reserve Margins

To examine the economic implications of the 1-in-10 resource adequacy standard, we conduct a series of reliability simulations using the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrape Consulting. We simulate a hypothetical Study Regional Transmission Organization (RTO) system with a peak load of 50,000 MW that is interconnected through 11,000 MW of transmission interties to three neighboring regions with a combined peak load of 130,000 MW and planning reserve margins of 15%. The hypothetical Study RTO and neighboring regions do not exactly reflect any particular real-world system, but have realistic characteristics based on actual systems' hourly load shapes, load diversity, resource mix, generation performance statistics, weather conditions, demand response penetrations, and other characteristics derived from actual U.S. power system data.

We probabilistically evaluate resource adequacy conditions by simulating hourly generation availability, load profiles, load uncertainty, transmission availability, and other factors to estimate standard reliability metrics including LOLE and LOLH, as well as the economic implications of different planning reserve margins. We use 9,600 annual simulations for each case and Study RTO planning reserve margin level to evaluate: (1) reliability outcomes considering hourly generation and transmission intertie outages, uncertainties in weather, hydro, wind, and solar conditions, and economic load growth uncertainty; and (2) economic outcomes including hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins.

Through these probabilistic multi-area simulations, we evaluate the physical reliability, economic, and risk mitigation implications of different planning reserve margins under varying study assumptions related to: RTO size, intertie size, renewable penetration, emergency and demand response (DR) penetration, the cost of new generating plants, multi-year forward planning periods and the size of load forecast error, varying energy market price caps, and energy-only or capacity market designs. We did not evaluate some factors such as fuel availability or common mode failures of generators, pipelines, and transmission components. While SERVM is capable of modeling the economic and reliability impacts of each of these drivers, the scope of this study is limited to variables most commonly analyzed in other reliability studies.

Planning Reserve Margin Results Based on Economics and Physical Reliability

In our Base Case simulation, the Study RTO requires a planning reserve margin of 15.2% to meet the 0.1 LOLE resource adequacy standard, or a planning reserve margin of 8.2% to meet the 2.4 LOLH standard. Figure ES-1 summarizes the economic implications of the planning reserve margin, showing the tradeoff between reliability event costs (that decrease with higher planning reserve margins) and system capital costs (that increase with planning reserve margins). A planning reserve margin of 10.3% yields the lowest total annual system cost from a risk-neutral, cost-of-service perspective. From a societal cost perspective, the risk-neutral economically-optimal planning reserve margin would be only 7.9% above the Study RTO's non-coincident peak load, if each Neighbor continues to maintain a 15% reserve margin above their own non-coincident peak load. A 7.9% Study RTO reserve margin combined with 15% Neighbor reserve margins is equivalent to an overall four-system reserve margin of: (a) 13.0% if

measured against the sum of the RTOs' non-coincident peak loads, and (b) 16.5% if measured against the coincident peak load of the combined system.[1]

Figure ES-1 also shows that the total average annual cost curve is relatively flat near the minimum cost point, indicating that expected total costs do not vary substantially between reserve margins of 8% and 14%. However, the lower end of that reserve margin range is associated with substantially more uncertainty in realized annual reliability costs and a much larger number of severe, high-cost reliability events.

Figure ES-1
Study RTO Reliability Costs as a Function of Study RTO Reserve Margin
(Risk-Neutral, Cost-of-Service Perspective)

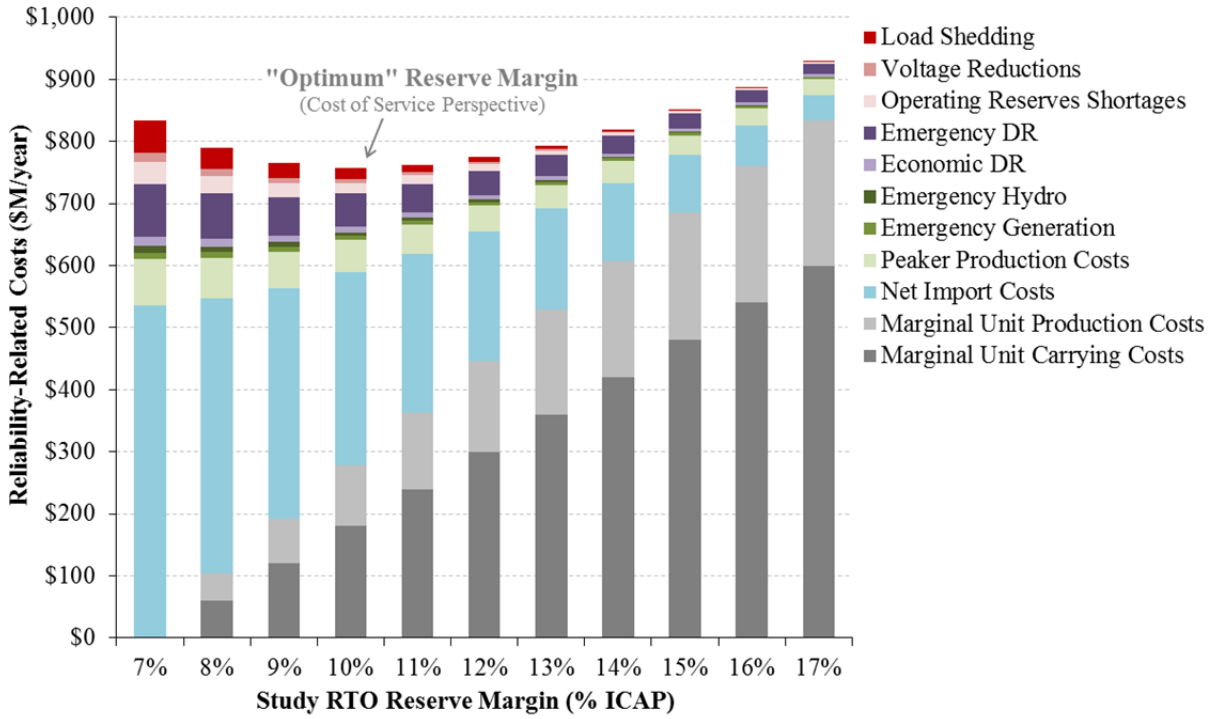


Table ES-1 summarizes the reliability-based and economically-based reserve margin targets for the Base Case simulation and for each of the alternative simulation cases we examined. These results show that varying assumptions regarding system size, topology, price cap, and other factors can substantially impact planning reserve margin targets. For example, the 0.1 LOLE reliability standard could require a reserve margin anywhere from 13.0% to 18.5% depending on the assumed system size, intertie level, and other characteristics. Similarly, economically-optimal reserve margins could vary anywhere from less than 6% to 16.5% from either a cost-of-service or societal perspective. The most significant factor impacting a region's planning reserve margin is the size of transmission interties, which resulted in Study RTO planning reserve margins ranging from 15.2% to 18.5% to maintain 0.1 LOLE or from 7.9% to 16.5% in terms of

[1] See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting convention.

economically-optimal reserve margins. Despite these differences, system characteristics have similar directional impacts on reserve margin targets for all resource adequacy criteria, both in terms of physical reliability and economics.

In addition to the simulation cases summarized in Table ES-1, we also analyze the implications of different levels of "emergency" and "economic" DR and different levels of intermittent renewable generation. With respect to dispatch-limited emergency demand response, we find that as emergency DR penetration increases, total costs initially decrease because these resources have lower capital costs than the conventional generation resources they replace. Even though emergency DR resources have a much higher dispatch cost than the displaced generating plants, the number of dispatch hours is low enough that it is advantageous to continue adding more DR initially. At higher penetration levels, however, limits on annual dispatch hours create a constraint after which it is no longer cost-effective to add emergency DR. Increasing the penetration of economic DR resources with unlimited call hours is more valuable in reducing system costs, with economically-optimal penetrations ranging from 8% to 14% depending on the fixed and variable costs of the assumed DR resources.

Table ES-1
Reliability-Based and Economically-Based Planning Reserve Margin Targets

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
Lower Price Caps					
$1,000 Price Cap Case	15.2%	8.2%	9.6%	8.7%	7.9%
$3,000 Price Cap Case	15.2%	8.2%	9.6%	9.5%	7.9%
Smaller System Size					
40% Size Case	14.8%	<6%	7.5%	<6%	<6%
40% Size and Transmission	15.1%	6.9%	8.1%	<6%	<6%
Neighbor Assistance					
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

Note:
Normalized Expected Unserved Energy (EUE) represents the percent of total energy not delivered (see Seciton I.B.1).

Market Design Implications

We also evaluate the implications of our simulation results within restructured wholesale power markets in which investments can only be attracted if prices are high enough on average for suppliers to earn the necessary return on their investments. Within energy-only markets, which do not rely on mandated planning reserve margins, investments must be attracted by net revenues earned from the energy market alone. Because supplier energy margins decline with increasing reserve margins, energy-only markets achieve an equilibrium reserve margin where net revenues

are equal to investment costs. Our simulations show that energy-only markets can attract the optimal level of generation investments from a societal-cost perspective. However, we also demonstrate that if energy prices are suppressed below true marginal system costs during load shedding or other scarcity events, an energy-only market design will not be able to maintain an optimal level of investments. This highlights the importance of efficient price formation during scarcity events through well-designed scarcity pricing mechanisms that reflect the marginal system costs of emergency interventions and deploying demand-side resources.

Because the reserve margin in an energy-only market is the result of economic incentives, there is no guarantee that such a market will achieve any particular reserve margin or reliability level. Energy-only markets can suffer from a "missing money problem" with insufficient economic incentives to invest in new resources. This missing money problem may result from two different types of challenges: (1) missing money arising from energy prices that are artificially suppressed, for example, by low price caps or inefficiently low market prices during scarcity conditions; and (2) missing money relative to what is needed to achieve the reserve margin that policy makers desire, which may be higher than what an economically efficient energy-only market would support.

Resource adequacy requirements can be imposed to address the missing money problem and attain desired planning reserve margin targets. Imposing such a requirement will make capacity a valuable product in addition to the energy and ancillary services that are compensated in an energy-only market. Maintaining a higher reserve margin requirement will yield higher capacity prices to compensate for declining energy margins. If energy and ancillary service market prices are suppressed by price caps or other factors, this will also translate into higher capacity prices. To date, capacity markets have been designed to achieve planning reserve margins based on physical reliability standards rather than economic objectives such as minimizing system costs.

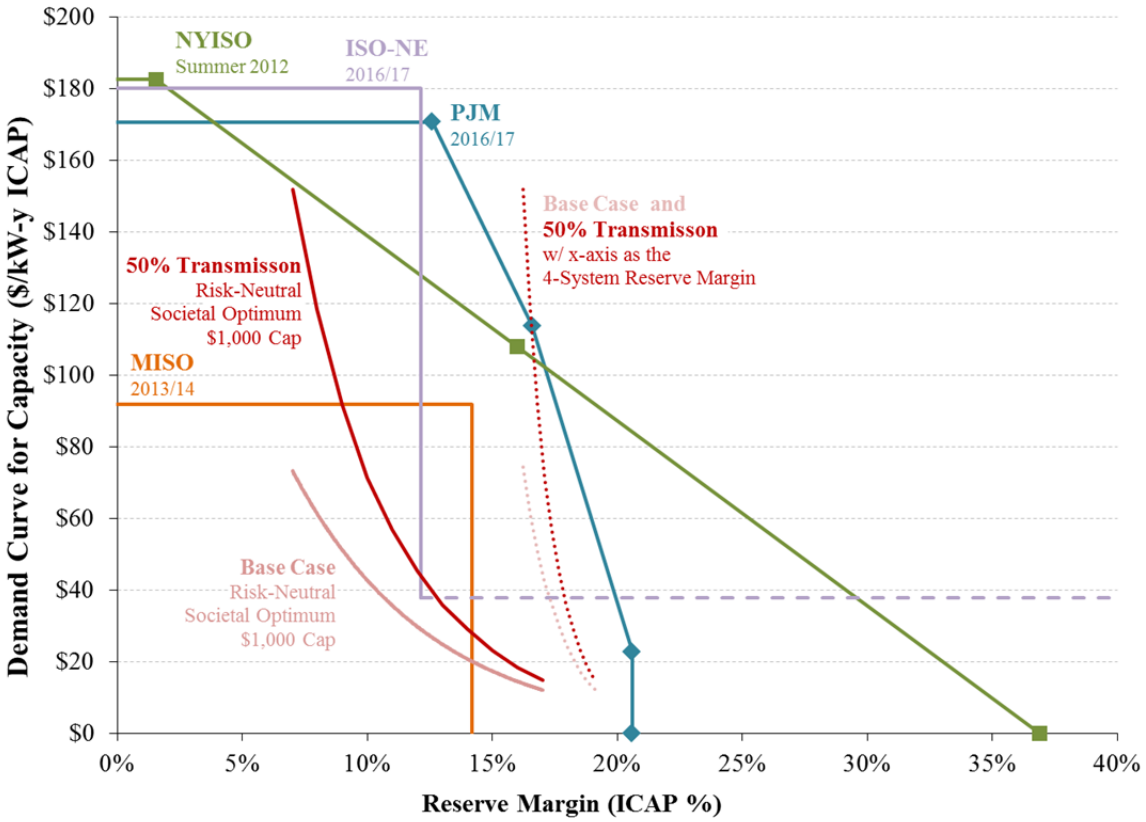
Our simulations demonstrate that a capacity market could be designed to achieve economically-optimal reserve margins through either: (a) imposing economically-based rather than physical reliability-based planning reserve margin requirements; or (b) implementing a demand curve for capacity that is designed to procure the cost-minimizing quantity of capacity. We show how such a cost-minimizing demand curve could be determined and compare the result to current RTO capacity demand curves as illustrated in Figure ES-2. The two red curves shown in the figures represent economically-optimal demand curves from a risk-neutral, societal perspective, assuming neighboring regions will maintain a 15% planning reserve margin. The risk-neutral cost-minimizing demand curves are plotted against: (1) the Study-RTO-internal reserve margin above Study-RTO non-coincident peak load (solid lines), as well as (2) the combined four-system reserve margin above the combined systems' coincident peak load (dotted lines).

We also examine the energy and capacity market outcomes at increased levels of DR penetration, assuming that DR will displace traditional generation. We show that increasing DR levels will result in increasing average energy prices, increasing energy price volatility, but decreasing capacity prices. Generally, economic DR that participates in the energy market has more favorable impacts on the market than dispatch-limited emergency DR. Currently, most DR assets have little incentive to participate in energy markets because energy market prices remain below their curtailment costs except under rare circumstances. However, at higher price caps

and higher DR penetration levels, we anticipate that more DR resources will migrate from emergency to economic programs.

Overall, we find that the choice of an energy-only or energy-plus-capacity market design does not by itself have great implications for average supplier net revenues or average customer cost. Because supplier's net revenues must on average be sufficient to recover investment costs in equilibrium, changing market design or reserve margins does not change the annual average of anticipated net revenues. Rather, it only changes the proportion of revenues that on average would be earned from the energy market versus the capacity market. For customers, average annual costs do increase as reserve margins rise above the risk-neutral cost-minimizing level, but this impact represents only a very small portion of customers' bills. In fact, increasing the planning reserve margin from the risk-neutral, societal optimum of 7.9% to the 15.2% reserve margin needed to maintain 0.1 LOLE increases average annual customer costs by only 1.5%, but substantially reduces the variance of annual cost outcomes, including the potentially very high costs of extreme events. Other features of the regional power market, such as the amount of intertie capacity to neighboring regions, have a much larger impact on total customer costs.

Figure ES-2
Cost-Minimizing Capacity Demand Curve vs. Current RTO Demand Curves



Notes:

All curves converted from source units into ICAP terms for both reserve margin and price.

Cost-minimizing demand curves plotted with x-axis as: (1) the Study RTO reserve margin against Study-RTO non-coincident peak load (solid lines); and (2) against the combined four-system reserve margin against the combined coincident peak load (dotted lines). See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting.

I. INTRODUCTION AND BACKGROUND

The Brattle Group and *Astrape Consulting* have been asked by the Federal Energy Regulatory Commission (FERC) to assess the economic implications of resource adequacy standards. In particular, we examine the widely-used one-day-in-ten-years (1-in-10) loss of load standard and compare it to alternative approaches to defining resource adequacy. In this Section we: (1) describe study scope and approach; (2) explain how 1-in-10 and alternative resource adequacy standards are determined; and (3) provide a summary that compares how various standards are implemented in practice.

A. STUDY PURPOSE AND APPROACH

The 1-in-10 loss of load event (LOLE) standard requires that an electric system maintain sufficient generation and demand response resources such that system peak load is likely to exceed available supply only once in any ten-year period. Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without an evaluation of its economic implications.[2] However, because the economic implications of different resource adequacy levels can be quite large, we and other industry observers have highlighted the need to examine the 1-in-10 standard from an economic perspective. To the extent that the economic value of resource adequacy standards is discussed in the industry today, there is no uniform approach to measuring the value of resource adequacy, such as the ability of incremental resources to reduce the frequency of customer outages and other emergency events, moderate energy price spikes, and increase wholesale competition. This lack of clarity makes it difficult for policymakers and industry participants to evaluate fundamental questions such as: (a) whether 1-in-10 criterion is still the right standard; (b) how higher planning reserve margins benefit customers; and (c) at what price capacity should be compensated.[3]

With this study, we seek to contribute to the understanding of these questions by developing a framework for assessing the economic value of resource adequacy and examining the implications of the 1-in-10 standard. We provide a brief summary of resource adequacy concepts in Section I.B, followed by a survey of how 1-in-10 and alternative resource adequacy standards are defined and implemented across North America in Section I.C.

In the remainder of the report we evaluate the economics of resource adequacy for a hypothetical interconnected power system that resembles existing regional transmission organization (RTO) and independent system operator (ISO) footprints. We use probabilistic simulation modeling to examine how reliability metrics, customer costs, and system costs vary with reserve margin. We also test the sensitivity of our results to input assumptions and underlying system conditions and compare the economics of the 1-in-10 standard to alternative reliability-based standards and standards based on economic objectives such as cost reduction and risk mitigation. We describe

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[2] Exceptions exist, particularly in the Southeastern U.S., where the utility and regulators explicitly consider the economic implications of planning reserve margins when setting the reserve margin target as summarized in Section I.C.1.

[3] For example, see Wilson (2010a-b).

our simulation approach and assumptions in Section II, report economic and reliability results in Section III, and summarize the implications for wholesale electricity market design in Section IV.

B. Approaches to Setting Resource Adequacy Standards

Resource adequacy can be assessed either in terms of physical reliability criteria or economic objectives. This section of our report defines the range of physical reliability criteria used in setting resource adequacy standards and explains how these standards are translated into target planning reserve margins. We then describe economic approaches to determining target planning reserve margins.

1. Interpreting 1-in-10 and Other Reliability Criteria

Although the 1-in-10 standard is widely used across North America, substantial variations in how it is implemented mean that it does not represent a uniform level of reliability. As recognized in recent work by the North American Electric Reliability Corporation (NERC) and Reliability*First* Corporation (RFC), the 1-in-10 standard may be interpreted as either *one event* in ten years or *one day* in ten years. *One event* in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. *One day* in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages.[4] These two interpretations can represent very different levels of physical reliability, although there is no direct translation between them unless one assumes a typical outage duration. For example, if one assumes a 4-hour outage, then the events-based definition represents a reliability standard with outage durations that are one-sixth the outage duration achieved by the LOLH-based definition.[5]

The 1-in-10 standard can also represent different levels of reliability for different systems. This is the case because neither the LOLE nor the LOLH metric considers the MW size of the outage endured. For example, a one-hour, 100 MWh outage event and a one-hour, 10,000 MWh outage event would be counted identically under the LOLE and LOLH metrics, even though the load shed amount under the second outage event is one hundred times greater in magnitude. Further, the 1-in-10 standard represents a higher level of reliability in a large system than in a small system because neither the LOLE nor the LOLH metric is normalized to system size.[6] This means that a 100 MWh, one-hour outage will have the same LOLE and LOLH values in a 10,000 MW and 100,000 MW power system, even though individual customers in the smaller system are ten times more likely to endure an outage. We further illustrate the differences among these various interpretations in Section I.C for actual power systems and in Section III for a hypothetical system with realistic assumed characteristics.

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[4] We also clarify that while we use these definitions of LOLE and LOLH throughout this report, others may use somewhat different definitions as we explain further in Section I.C.

[5] In other words, 0.1 LOLE times a 4-hour outage results in 0.4 LOLH per year, or only one sixth of the 2.4 LOLH assumed in the hours-based interpretation. However, the comparison depends entirely upon the assumed outage duration.

[6] This is true as long as the one event represents a smaller proportion of total load in a large system than in a small system.

Recognizing these limitations of the 1-in-10 standard, a recent NERC task force recommended using Normalized Expected Unserved Energy (EUE) as a new physical reliability metric.[7] Normalized EUE is the total expected firm load shed due to supply shortages, divided by the total system net energy for load, and therefore represents an overall percentage of system load that cannot be served. We agree with that report's conclusion that Normalized EUE is the most meaningful reliability metric that can be compared across systems of many sizes, load shapes, and other uncertainty factors. In fact, Normalized EUE is already used in some international markets to set minimum reliability thresholds or trigger administrative interventions, although the metric may be referred to as Loss of Load Probability (LOLP) or Unserved Energy (USE). Examples of metrics equivalent to Normalized EUE that are used in international markets include: (a) a 0.001% LOLP standard in Scandinavia; and (b) a 0.002% USE standard in Australia's National Energy Market (NEM) and South West Interconnected System (SWIS).[8]

Unfortunately, these and similar terms such as the Probability of Lost Load (POLL) are also not used and defined uniformly. For our purposes and for the remainder of this report we will refer only to: (1) LOLE measured in events per year; (2) LOLH measured in hours per year; and (3) Normalized EUE measured in percent of system-wide load unserved. While there is not a direct translation among these three physical reliability metrics (unless one assumes an average outage size and duration), they can be estimated and compared for an individual system that has a particular distribution of expected load and other uncertainty factors. Section III presents such comparisons.

Also note that, historically, the 1-in-10 standard as applied by system operators in North America translates to expected annual outages for end-use customers that average less than a few minutes per year on a system-wide basis. This compares to total customer outages averaging several hundred minutes per year on a system-wide basis, most of which are caused by distribution system outages.[9] Nevertheless, despite the fact resource adequacy-related reliability events account for only a very small fraction customer outages, such "rolling blackouts" attract disproportionate media and political attention whenever they happen.[10]

2. Determining System Reliability as a Function of Planning Reserve Margin

The 1-in-10 resource adequacy standard is not a readily observable metric. For example, one cannot simply review a region's integrated resource plan (IRP) or reserve margin outlook to determine whether the 1-in10 standard will be achieved. This is because such supply-related

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7 See the NERC (2010).

8 See Nordel (2009), p. 5; AEMC (2007), pp. 29-30, (2010), p. viii.

9 See Newell, *et al.* (2012), pp. 101-2.

10 For example, during the summer of 2012, the Alberta Electric System Operator (AESO) instituted load shedding due to heatwave-related peak loads and unexpected generation outages. This required rolling 30-minute curtailments of 200 MW of firm system load over a two-hour period. Despite attracting substantial media and political attention (see, for example, Sellin (2012) and Henton (2012)), this 200 MW curtailment affected only approximately 2% of almost 10,000 MW of total system load, which means an average customer outage duration of only approximately 2.4 minutes (2% of 120 minutes) on a system-wide basis. Only 3 such events occurred in Alberta in the last decade, one on July 2, 2013 (but triggered by a transformer outage, not resource adequacy constraints).

reliability outcomes depend on a host of complex factors such as anticipated resource mix and weather uncertainty. For this reason, most system operators use reliability modeling to translate the 1-in-10 standard into a planning reserve margin.[11] Such reliability modeling is used regularly even in markets without explicit resource adequacy requirements, including Texas, Alberta, Australia's NEM, and Scandinavia, to monitor reliability levels and determine whether administrative interventions are warranted to maintain adequate system resources.[12]

For markets with explicit planning reserve margin requirements, the requirement is typically calculated based on probabilistic reliability modeling that simulates LOLE as a function of the level of installed generating capacity. Such a simulation exercise requires statistically characterizing the uncertainty in forecasted load, the reliability of the generation fleet including intermittent resources, the likely availability of imports, and a number of other factors as explained further in Section II. The simulations are used to estimate reliability levels over a range of reserve margins, showing that the number or duration of expected load shed events decreases as capacity is added and the planning reserve margin increases.

Figure 1 illustrates how LOLE may decrease with reserve margin, showing an example where a planning reserve margin of 15% would be needed to achieve the 0.1 LOLE standard. We implement this type of reliability modeling for a realistic but hypothetical RTO in this study, as discussed in Sections II through IV.

To understand the economic value of different resource adequacy levels, one must also estimate the value of reliability to customers. One component of this reliability value is the ability to avoid costly load shedding events, the value of which can be estimated by: (1) determining the approximate value of lost load (VOLL), which is the cost of an outage to customers or the price that an average customer would be willing to pay to avoid an involuntary interruption of their electricity supply; and (2) multiplying VOLL by the amount of load shed. This estimate of the

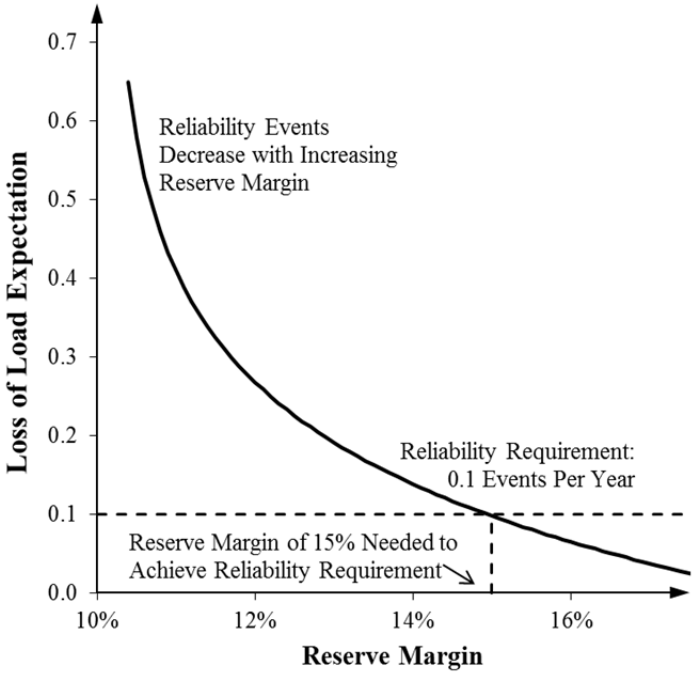
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[11] In addition to planning reserve margins based on installed generating capacity and anticipated (50/50) peak load during normal weather conditions, power markets also require various types of "operating reserves" such as regulating reserves, spinning reserves, non-spinning reserves, and replacement reserves. Operating reserves are needed to balance load and supply reliably on a moment-by-moment basis and enable the system operator to quickly and reliably react to contingency events. In contrast to operating reserve requirements, which apply during real-time system operations irrespective of load levels or plant availability, planning reserve margins are meant to ensure that sufficient supply is available to address reliability challenges due to differences between: (1) near-term or medium-term peak load forecasts (which reflect average weather) and typical generation outages; and (2) actual peak loads (which can exceed reflected weather-related spikes in load) and spikes in generation outages. Because of the differences between forecast and actual peak loads, the year-to-year realized reserve margin will fluctuate considerably around the average. In this section, as well as throughout this report, we refer to "planning reserve margin," "target reserve margin," or simply "reserve margin" to refer to this forward-looking estimate of installed capacity (ICAP) relative to the forecast normalized peak load. We refer to "operating reserves requirements" or "operating reserves" when referring to the quantity of regulating and contingency reserves that are needed to maintain real-time grid stability in every hour.

[12] AESO developed its long-term adequacy (LTA) metrics to determine a forecast level of reliability at which point AESO may need to intervene in the market, see AESO (2008), Section 1. For additional discussion on similar regulatory methods in other countries, see Pfeifenberger, Spees, and Schumacher (2009), pp. 28-29.

economic cost of load shed events will be a decreasing function of the reserve margin with a shape similar to that in Figure 1.[13] However, as we discuss further below, the system-wide expected VOLL is only one component of total reliability-related system and customer costs that must be considered when evaluating the economic implications of different resource adequacy levels.

Figure 1
Reliability vs. Reserve Margin



Notes:
Illustrative figure does not represent any actual or simulated system.
Similar charts for real systems are available in various reliability studies, for example see Electric Reliability Council of Texas (ERCOT) results in ECCO (2013), pp. 8-9.

3. Determining Economically "Optimal" Reserve Margins

To understand economic tradeoffs over a range of planning reserve margins, one must also estimate the incremental value and costs associated with additional capacity resources. In this study we implement such economic reliability simulations to assess these tradeoffs, building upon previous studies conducted for regulated entities and in academia.[14] In particular, *Astrape Consulting* has conducted a number of such studies using the Strategic Energy Risk Valuation Model (SERVM) reliability simulation tool, which we also use to analyze the case studies

[13] See Wilson (2010a) and Centolella (2010).

[14] For example, a 1992 study for Pacific Gas and Electric compared the traditional 1-in-10 standard against a value-of-service approach, showing that the traditional standard required a reserve margin of 22.5% while the value-of-service approach indicated an efficient reserve margin of 16.2%. See Keane, *et al.* (1992), pp. 824, 826. For similar analyses, see also Poland (1988), p.21; Munasinghe (1988), pp. 5-7, 12-13; and Carden, Pfeifenberger, and Wintermantel (2011).

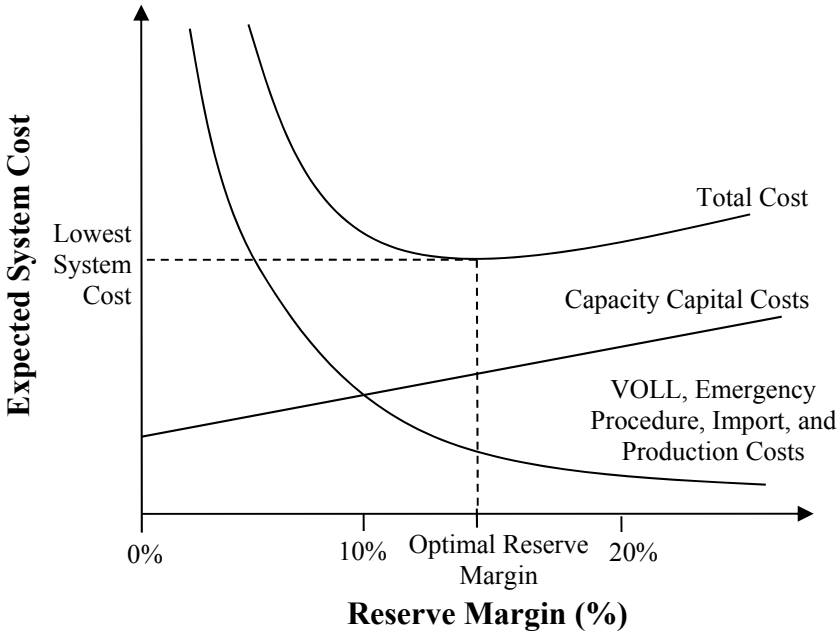
presented in this report. The objective of such an economic reliability study is to determine an "optimal" reserve margin that minimizes total system or customer costs, including the capital cost of adding resources, production costs, off-system and emergency purchase costs, and the cost of load shed events.

The objective of minimizing total system costs is demonstrated schematically in Figure 2. The figure shows that increasing the planning reserve margin will increase capital costs as more resources are added to the system. However, increasing the reserve margin also reduces outage costs by reducing the frequency, duration, and magnitude of load shed events, may reduce production costs by reducing the need to dispatch higher-cost peaking resources, and may reduce power purchase costs by reducing the need to call on higher-cost imports during reliability events.[15] The "optimal" reserve margin is that which minimizes expected system or customer costs by weighing the tradeoff between the incremental costs and the benefits of increasing the reserve margin.

However, this cost-minimizing reserve margin only represents the point at which costs are minimized on an expected value basis, and therefore represents the "optimum" reserve margin from a risk-neutral perspective. As we discuss further in Sections III.A.2–4 below, the point of the lowest system cost represents the probability-weighted average cost over many possible system conditions. This probability-weighted average cost is influenced greatly by low-probability, very-high-cost shortage events, such as an extreme heat wave that happens to coincide with substantial generation outages. Because customers and policy makers are risk averse, avoiding such high-impact events will be valuable. Customers and policy makers may therefore prefer to pay more to maintain a somewhat higher reserve margin that can mitigate the risks and impacts of extreme shortage events.

[15] The magnitude of avoided load shed costs will not typically depend on what type of capacity resource is added because many types of resources have similar likelihoods of being available for dispatch during load shed events. However, the magnitude of net reductions in production costs, avoided import costs, and increases in capital costs are highly dependent on the type of capacity added. For example, adding combustion turbines (CTs) will incur lower capital costs than adding combined cycles (CCs), but will also provide fewer benefits from avoided production and import costs. For this reason, the "optimal" reserve margin depends on the type of marginal technology assumed when varying the reserve margin as discussed further in Section III.B.3.

Figure 2
"Optimal" Reserve Margin at Lowest System Cost



Notes:
Illustrative figure does not represent any actual or simulated system.
See Sections III.A.2–4 for a more thorough discussion and estimate of the economic optimum within a hypothetical simulated system.

C. SURVEY OF RESOURCE ADEQUACY CRITERIA IN NORTH AMERICA

This section documents variations in how the 1-in-10 and alternative resource adequacy standards are used and interpreted in existing power markets across the U.S. and Canada. This discussion is based on our interpretation of RTO and utility planning and reserve margin studies as summarized in Appendix A. However, we caution that, to completely understand the nuances and complexities of these studies, one would need to discuss implementation details with the individuals responsible for conducting the studies. The public documentation of these studies is often insufficiently detailed or can easily be misinterpreted. Because we have not conducted such interviews to be able to document the assumptions and the complexities of each study, our discussion should be interpreted as a preliminary summary of general industry practices, not a fully-verified documentation of any one region's approach.

As we explain, most of these regions rely on a 1-in-10 reliability standard, but substantial variations in interpretation, conventions used in calculating reserve margins, modeling approaches, and underlying system conditions make it very difficult to meaningfully compare different systems' reliability levels and reported reserve margins.[16]

[16] The markets we survey here include PJM Interconnection (PJM), New York ISO (NYISO), ISO New England (ISO-NE), California ISO (CAISO), Northwest Power Pool (NWPP), Florida Reliability Coordinating Council (FRCC), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool
Continued on next page

1. Differing Resource Adequacy Standards

Appendix A.1 summarizes the resource adequacy criteria established by system operators and reliability coordinators across the U.S. and Canada. As shown, the majority, but not all, of these regions use the 1-in-10 resource adequacy standard. Most of these regions define 1-in-10 as 1 event in 10 years, or 0.1 LOLE per year. However, SPP differs in that it interprets 1-in-10 as 24 hours of curtailments in 10 years, or 2.4 LOLH per year.

Several reliability operators in the Southeast establish resource adequacy targets based on economic analysis with the objectives of minimizing customer costs and mitigating the risk of high-cost events. Other entities use alternative physical reliability criteria tailored to their own needs, such as the BC Hydro system that must also consider the potential for energy-constrained low-hydro conditions leading to overall energy limitations. Finally, Texas and Alberta both have reliability targets but do not impose these targets as mandatory standards for resource adequacy.

2. Differing Conventions for Calculating Reserve Margins

One important reason that it is difficult to compare the level of resource adequacy across systems is that each region adheres to a different set of conventions when calculating their reserve margins. In other words, even if two regions had identical peak load and expected resource mix, they may calculate different reserve margins using different conventions. In fact, even within a single market, there may be different approaches used when calculating reserve margins for the purposes of publishing summer or long-term resource adequacy assessments, conducting transmission planning exercises, conducting a reliability studies, or implementing a capacity market.

a. Accounting for Demand-Side Resources

All regions have some demand response (DR), load curtailment, retail price response, or other load-side resources that contribute to resource adequacy. Aside from the fact that it is sometimes difficult to estimate the total resource adequacy value of a particular type of DR program, there is also no standard approach regarding how these resources are included in the reserve margin calculation. Some entities include demand response as a reduction in load while other regions include it as a supply-side resource.

Example: DR counting as a supply-side resource versus a reduction in load changes calculated reserve margin (RM) by 5% from 20% to 25%.

Assume:

Load = 100,000 MW
Gen = 100,000 MW
DR = 20,000 MW

Reserve margin if treating DR as supply resource:

Continued from previous page

(SPP), and various SERC Reliability Corporation (SERC) and Western Electricity Coordinating Council (WECC) entities. We draw upon previous NERC surveys as well as individual entities' planning and reliability modeling documentation. For example, see NERC (2010a).

RM = (Gen + DR) / Load – 100%
20% = (100,000 + 20,000) / 100,000 – 100%

Reserve margin if treating DR as a reduction in peak load:
RM = Gen / (Load – DR) – 100%
25% = (100,000) / (100,000 – 20,000) – 100%

Further, there are different conventions used for adjusting nominal DR capability by: (a) derating that capability by an expected availability rate; or (b) if treating DR on the supply side, possibly grossing up the nominal capacity value for avoided line losses and reserve margin requirements. These differences in DR accounting change the numeric value of the planning reserve margin, but not the system's underlying resource adequacy situation.

b. Accounting for Emergency Operations

Similarly, while all regions implement various types of emergency procedures before shedding load, there is no standard approach as to how these procedures are accounted for when calculating reserve margins. For example, PJM will implement voltage reductions and may achieve approximately 2.5% reduction in peak load before firm load shedding is required. In the Southern Company (SoCo) region, approximately 2% of peak load is available from voltage reduction and other emergency procedures.[17]

However, the regions differ in terms of how these procedures are accounted for in their reserve margins, with PJM not considering the capacity benefit of emergency procedures and SoCo treating emergency procedures as supply resources. Overall, as summarized in Table 1, the convention of whether to count emergency procedures as a supply resource, load reduction, or neither would result in calculated reserve margins ranging from 15.6% to 18.6% in PJM and from 13.0% to 15.3% in SoCo.

Table 1
Emergency Procedure Accounting Impact on PJM and SoCo Reserve Margins

	Load Reduction from Emergency Procedures	ICAP Reserve Margin			
		As Reported	Emergency Procedures Counted as Supply Resources	Emergency Procedures Counted as Load Reduction	Emergency Procedures Not Counted
	(%)	*(%)*	*(%)*	*(%)*	*(%)*
PJM	2.5%	15.6%	18.1%	18.6%	15.6%
SoCo	2.0%	15.0%	15.0%	15.3%	13.0%

Sources and Notes:
As-reported reserve margin requirements from PJM (2012c), and Georgia Power (2010).
Alternative reserve margin calculations assume no change other than how voltage reductions are included or not.

[17] PJM voltage reduction value approximately calculated from PJM (2012a), p. 63.

c. Derating Capacity from Different Resource Types

When calculating the reserve margin, some planning regions include all resources at their nameplate capacities, while others include only a derated capacity value for intermittent or dispatch-limited resources, such as wind, solar, hydro, or storage. These derated capacity values are calculated using a variety of different approaches.[18] The decision of whether to derate certain resource types and, if so, how to calculate the derate magnitude, is partly a matter of convention and partly a reflection of the importance of various resource types in the overall resource adequacy picture in a particular region. For example, a region with few hydro resources may not place particular emphasis on developing a detailed assessment of those assets' reliability value; while a hydro-dominated region such as British Columbia must conduct detailed evaluations of its hydro resource base and probabilistic availability under a number of weather and hydrology scenarios.

To illustrate the importance of derate accounting conventions, we compare the conventions PJM and NYISO used in their reliability assessments. PJM adopted a 15.6% installed capacity (ICAP) planning reserve margin target in its most recent reliability study.[19] Under PJM's resource accounting methodology, demand response is derated to 95% of nameplate capacity, wind to 13%, and solar to 38% of nameplate capacity.[20] In comparison, NYISO calculates an ICAP reserve margin requirement of 16.1%, but uses the full nameplate capacity of all its resources in that calculation.[21] As explained in the NYISO study, this difference in accounting conventions has a substantial impact on the calculated ICAP reserve margin, particularly under very different levels of wind penetration.

Taking NYISO's resources and using PJM's derate methodology, NYISO's 16.1% ICAP reserve margin target would decrease to 10.7% as shown in Table 2 below. PJM's target reserve margin using the NYISO's resource accounting methodology would increase to 16.8% from 15.6%.

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[18] For example, for wind, PJM uses a unit-specific availability calculation over a three-year history during summer peak hours, while the Midcontinent ISO (MISO) conducts a fleet-wide Effective Load Carrying Capability (ELCC) study each year. See PJM (2010), MISO (2012a).

[19] Note that PJM conducts a new reliability study each year, and in each study may recommend a different reliability requirement for each delivery year. In this subsection we refer to the year 2012 reliability study as effective for the 2016/17 delivery year, see PJM (2012c).

[20] To add an even further layer of complexity, the capacity market through which the reserve margin requirement is procured is conducted on an unforced capacity (UCAP) rather than ICAP basis as discussed further in the following subsection I.C.2.f. The deratings reported here apply to the calculation of the ICAP reserve margin. However, a different, additional adjustment is also applied to each resource type when calculating its UCAP value. For the purposes of calculating UCAP from ICAP, DR resources' capacity value is grossed up to account for avoided reserve margin needs, most generators' capacity value is reduced according to unit-specific outage rates, and wind and solar units' derated capacity value is the same on either an ICAP or UCAP basis. See PJM (2012c, 2010, 2013a).

[21] For the 2012/13 delivery year, as estimated in the 2011 study. As in PJM, there is also a separate translation for determining the UCAP capacity value of each resource as would be used in the capacity market. See NYSRC (2011).

Table 2
Illustration of Differences in PJM and NYISO Target Reserve Margin Calculations

	Peak Load	Nameplate Capacity			Derated Value			ICAP Reserve Margin		
	Summer 2012	Wind	Solar	DR	Wind	Solar	DR	As Reported	Using Nameplate Capacity	Using Derated Capacity
	(MW)	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*
PJM	151,394	1,305	564	7,263	13%	38%	95%	15.6%	16.8%	15.6%
NYISO	33,335	1,648	39	2,192	11%	65%	85%	16.1%	16.1%	10.7%

Sources and Notes:
See PJM (2012c), NYSRC (2011).
We do not attempt to document the entirety of differences in reserve margin accounting, but only illustrate the impact of these specific derating conventions applied over this reported quantity of resources. A number of other factors related to how these resources are modeled will also influence the reserve margin calculation, which we do not attempt to discuss here.
NYISO DR value refers only to special case resources (SCRs), see NYSRC (2011), p. 51.

This shows that, while NYISO's reported ICAP reserve margin target exceeds that of PJM, it is lower than PJM's when calculated on a comparable basis. But note that, because the technical details of resource adequacy studies and the regions themselves can vary considerably, even if PJM's and NYISO's reserve margins were calculated consistently with respect to the treatment of the resources' nameplate capacity, a lower reported planning reserve margin would not necessarily mean lower reliability.

d. Uncommitted Resources, Planned Retirements, and Planned Additions

Another difficulty in comparing reserve margins across regions or even within a particular region is that one must determine whether and how to account for resources that may or may not be available in a future delivery period. In particular, there are different approaches to accounting for:

Uncommitted Resources that exist within the footprint and so are likely to provide resource adequacy value, but that do not have any firm commitment to be available through either a contractual agreement or a capacity market obligation. Without a firm commitment to provide internal capacity, these resources are free to retire or export their capacity and so may not be available when needed.[22]

Planned Retirements are sometimes known with substantial lead time and so can be properly accounted for. But in many cases plant owners do not have to report retirements to the system operator until shortly prior to the delivery period. This uncertainty is currently of substantial concern in MISO, where a large number of coal plants are at risk for retirement under the Mercury and Air Toxics Standard (MATS). However, the RTO has a limited

[22] This is one reason that some RTOs including PJM separately report committed and uncommitted "reserve margins" when conducting summer resource assessments, see PJM (2013e).

forward view regarding the quantity and location of these retirements, which introduces substantial uncertainty for both transmission and resource planning.[23]

Planned Additions are similarly uncertain on a forward basis. The majority of announced generation projects are never brought into commercial operation, but may be partly developed before being postponed or cancelled depending on market and site conditions. For this reason one must carefully evaluate the commercial probability of various proposed resources when calculating a future reserve margin, for example, by assigning different probabilities that each resource will come online depending on how far along it is in the development process.[24]

Again, the conventions used to account for these resources change the reported reserve margins despite the fact that they do not change the underlying resource adequacy position. Unfortunately, attempting to standardize the treatment of these uncertainties may be counter-productive, since the most appropriate convention to use is highly dependent on the purpose for which the reserve margin is calculated. For example, a transmission planning study that looks five to twenty years into the future must include some reasonable assumptions about speculative additions and retirements, while a near-term summer assessment may most appropriately consider only committed resources that can definitely be relied upon.

The large range in different reserve margins that can be calculated using different conventions is illustrated each year in the annual NERC *Long Term Reliability Assessment* (LTRA) that documents the reserve margin outlook for all regions. To help with some standardization across regions, NERC provides guidance regarding how to account for uncertain resource types for a range of optimistic or pessimistic outlooks. This improves the ability to compare outlooks across regions, but does not solve the problem entirely due to differences in interpretation, even on a very near-term basis where uncertainty is lowest. For example, the 2012 LTRA outlook reports the summer 2013 anticipated reserve margins for 26 different regions, of which: (a) 12 reported no difference between the most pessimistic and optimistic reserve margin outlooks for the summer of 2013; (b) another 8 reported up to 1% uncertainty range; (c) another 3 reported up to 10% uncertainty range; and (d) another 3 reported higher uncertainty ranges of up to 18% difference between the most optimistic and pessimistic cases.[25] The ranges diverge even further when looking further into the future.

e. Accounting for Tie Benefits

Being interconnected to neighboring regions can improve resource adequacy in two ways. First, by enabling a region to procure *firm commitments* from external resources to supply and deliver power during emergency events. And second, by creating *tie benefits* that enable the region to request neighbor assistance, if available, through non-firm imports during emergency events. The latter type of assistance is neither guaranteed nor contractually obligated to materialize, but

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[23] For example, see a discussion of these uncertainties and MISO's concerns about these uncertainties in MISO (2013b).

[24] PJM uses this approach for a number of purposes, see PJM (2012c).

[25] See NERC (2012), p. 68.

the likely availability of these tie benefits can be probabilistically evaluated as discussed in Section I.C.3.d below.

It is standard practice to include firm imports on the supply side of a reserve margin calculation, but there is no standard practice for how to include tie benefits. For example: (a) the most common approach, such as used in PJM and MISO, is to exclude tie benefits from the calculated reserve margin, which means the target reserve margin is lower than it would be if tie benefits were included as a resource; (b) some regions, such as ERCOT, treat all or part of their interties as a supply resource that increases the calculated reserve margin; (c) other regions, such as Alberta, sidestep the problem of evaluating the reliability value of the interties by simply reporting the reserve margin with the interties contributing at zero or 100% of their path rating; (d) some regions, such as SPP, do not account for tie benefits at all; and (e) yet other regions have special circumstances, such as ISO-NE's separate treatment of two portions of the tie benefits, one part that is specifically allocated to entities that own the rights to an intertie with Québec, and another part that is allocated equally to all loads.[26]

f. Accounting for Installed and Unforced Capacity

A final source of discrepancy is the differing conventions for expressing resource adequacy targets either in terms of: (1) "installed" capacity ratings that account for thermal generators at their maximum output capability; or (2) "unforced" capacity ratings that discount resources' capacity rating by an expected forced outage rate (EFORd). All regions use ICAP reserve margins for most reporting purposes, including summer and long-term resource assessments. However, even under ICAP accounting there are varying degrees of uncertainty. For example, it is relatively easy to find the same plant listed at different ICAP values since the RTO may be reporting a nameplate, summer, winter, emergency maximum, committed, or an annual capacity test value. It is not unusual for an individual thermal generation resource to have reported capacity values that vary by many percentage points.

The consequences of such accounting discrepancies can have high financial implications in regions with bilateral or centralized capacity markets, with individual suppliers' capacity payments potentially materially impacted by such differences. For this reason, MISO, PJM, and NYISO have all opted to conduct their capacity auctions on a UCAP basis, which more systematically accounts for individual resources' summer availability after accounting for unit-specific historical availability ratings.[27] Under UCAP accounting, all resource types are derated to their expected "unforced" availability during summer peak conditions so that resources have a more similar contribution to resource adequacy. While the approach to calculating UCAP is different for each resource type and also varies by region, the UCAP-based reliability requirement is more meaningful and comparable under different resource mixes and across regions. Despite the advantages of UCAP accounting, however, RTOs generally continue their

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[26] See PJM (2012c); MISO (2012c); ERCOT (2013b); SPP (2012b), p. 20; ISO-NE (2012); and AESO (2013).

[27] However, both California's Resource Adequacy Requirements and ISO-NE's Forward Capacity Market are implemented using ICAP accounting.

historical approach of reporting ICAP-based planning reserve margins for nearly all purposes other than capacity auctions.

3. Differing Approaches to Conducting Reliability Modeling

Even though most of the planning entities surveyed define the 1-in-10 standard as 0.1 LOLE, the resource adequacy levels of these regions nevertheless may not be comparable. Each system operator conducts its own LOLE study using a range of different modeling assumptions. As a consequence 0.1 LOLE does not represent the same level of reliability in each system. These differences result from using different reliability modeling tools and a wide range of different study assumptions.

In this section, we highlight a number of important factors that create these discrepancies. In Appendix A.2 we further illustrate the wide range of approaches by summarizing those used for ISO-NE, NYISO, PJM, MISO, SPP, and SoCo.[28] To fully understand reliability differences across different systems, all studies and reserve margin calculations would need to be undertaken using consistent assumptions, methodologies, and definitions. A recent initiative by NERC resulted in recommended modeling assumptions that attempt to reconcile at least some of these existing discrepancies.[29] We also note that this list of differences among modeling approaches represents only a small subset of all potential differences, and that we have not attempted to document other important factors such as hydro resource modeling, wind resource modeling, approaches to characterizing correlations among load, wind, hydro, and generator outages, or approaches to calculating sub-regional resource adequacy requirements.

a. Different Reliability Modeling Packages

Different system operators use different models to conduct their reliability studies, including GE-MARS, SERVM, ABB Gridview, Genesys, and other non-commercially available models such as PJM's Prism Model and Florida Reliability Coordinating Council's (FRCC's) TIGER Model.[30] The models differ considerably, including in the range of uncertainties considered and how these uncertainties are captured in simulations. These differences can translate to very different study results.

b. Definition of Reliability "Events"

Regions that use the 0.1 LOLE standard hope to achieve a resource adequacy level of only one "event" in ten years. However, as noted previously, there is no standard approach for determining what constitutes a reliability "event." Some LOLE studies and system operators define a reliability event as any event requiring emergency operating procedures, such as calling

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[28] Tennessee Valley Authority (TVA), Duke, Progress Energy, Louisville Gas and Electric Company (LG&E), and Kentucky Utilities Company (KU) use assumptions similar (though not identical) to SoCo. For example, TVA does not include DR as a resource. Duke, Progress, LG&E, KU, and TVA define a reliability event as an event that requires the depletion of spinning reserves, whereas SoCo defines a reliability event as an event that requires depletion of any type of operating reserve.

[29] NERC (2010b).

[30] See Appendix A.1 for a summary of the reliability modeling packages used in various systems.

demand response, implementing voltage control, or depleting operating reserves. In other systems, the studies consider reliability events as contributing to the tabulated LOLE only if operating reserves are depleted *and* firm load must be shed. Finally, many reliability studies do not explicitly account for the nature, order, and impact of various emergency intervention events. These factors can have a substantial impact on study results as illustrated in Section III.A.1 below.

c. Treatment of Load Uncertainty

One of the most important factors driving resource adequacy is uncertainty in peak load, which is driven by both weather uncertainty and economic forecast uncertainty.[31] For example, the combination of the number of weather years studied, the process used to derive peak and hourly loads under normal weather conditions, and the probabilities assigned to extreme weather patterns can change planning reserve margin targets by several percentage points. For example, a recent LOLE study by ERCOT found differences in weighting the 2011 weather year, which some refer to as a 1-in-100 year heat wave. Depending on how likely such extreme weather is to recur, the resulting target reserve margins would range from a low of 13.7% (with zero probability) to a high of 18.9% (with a 5% probability).[32] Even differences in how the projected load growth is applied to a base-year profile yielded target reserve margins ranging from 15.3% to 16.1%.[33] As another example, some regions such as PJM consider uncertainty due to economic load forecast error over the planning horizon when calculating the reserve margin needed to meet 0.1 LOLE, while other regions such as ISO-NE exclude this portion of load forecast uncertainty and instead consider only weather-related load uncertainty.[34]

d. Estimating Tie Benefits

As explained in subsection I.C.2.e above, regions differ in how they account for tie benefits in their reserve margin calculations. In this subsection, we further explain how regions differ in their approaches to estimating tie benefits. Some studies assume a maximum import capability or tie benefit, simply counting that quantity as a firm resource. Other studies explicitly model surrounding regions' load and resources to probabilistically estimate the availability of imports during reliability events. Among the regions that do probabilistically assess tie benefits, differences in modeling approaches include assumptions regarding:

Maximum Intertie Ratings – Determining the total quantity of intertie capability to use in resource adequacy studies is not as simple as calculating the line ratings for every import point in a region. Instead, this is a complex engineering estimate that must consider simultaneous import capability from multiple directions under the expected peak season power flows. Further, the maximum intertie portion used for the purposes of calculating non-firm tie benefits is the total path rating minus any portion of the interties already used to support firm import commitments as discussed further in Section III.B.2 below. Most

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31 As discussed further in Sections II.D and III.A.5 below.

32 ERCOT (2013a), pp. 24-26.

33 ERCOT (2013b), Section 2.2.3 (p. 4) and pp. 7-8.

34 See PJM (2012c) and ISO-NE (2012).

systems use simplified assumptions about maximum intertie ratings that may not be updated regularly to reflect changing system conditions.[35]

Probabilistically Available Intertie Capability – Many reliability studies assume a fixed path rating and assume that the transmission will be entirely available at all times. However, this is not strictly true since every path may have variable availability, for example due to simultaneity, line outages, or temperature deratings. Some studies probabilistically account for these uncertainties in path ratings, as we do in the hypothetical RTO simulations presented in this report.[36]

Load Diversity – One of the important drivers of tie benefits is the extent of load diversity across regions. For example, if one region experiences a peak load emergency while the neighboring region does not, then assistance should be available over the interties. However, the scale and variability of load diversity can be characterized in many different ways. For example, NYISO's planning models simulate neighboring regions, but assume that all neighboring regions have the same highest peak-load hours, all based on a single historical year. As explained in their study, this is a conservative assumption that reduces the amount of capacity that would be available from neighboring regions during NYISO reliability events.[37] In contrast, PJM's planning study assumes different levels of peak load diversity with each of its neighbors, meaning that PJM assumes other regions' peak loads are a certain percentage below their respective non-coincident peak loads when PJM is peaking.[38] This will yield a higher resource adequacy value of interties with neighboring regions, thereby reducing the likelihood of load-shed events and the corresponding target planning reserve margins. Other studies, including the simulations presented below, rely on a large number of historical weather years for the study region and neighboring regions to more accurately capture the benefits of tielines and load diversity. For example, the simulations in this report are based on 32 different synthetic annual load shapes for the Study RTO and neighboring regions based on 32 years of actual historical load data in each region.[39]

Supply in External Regions – To calculate tie benefits, it is also necessary to assume the level of supply in each neighboring region and the extent to which such resources will be made available for neighbor assistance during reliability events. This requires assuming reserve margins for each neighboring region, including whether to model the external market at their planning reserve margin target or at their most likely actual level of installed capacity. Further, studies differ in the extent to which each region is assumed to dispatch demand response or other energy-limited resources to provide assistance to its neighbors.

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[35] For example, PJM uses a total assumed simultaneous intertie capability or Capacity Benefit Margin (CBM) of 3,500 MW to be used for the purposes of calculating tie benefits. This rating has not been updated since at least 2007, even though the RTO's footprint has expanded several times since then and intertie topology and capability would necessarily have changed at least somewhat. See PJM (2007, 2012c).

[36] See Section II.B.

[37] See NYSRC (2011), p. 47.

[38] See PJM (2012c), p. 75.

[39] See Section II.D and Appendix B.5 for additional discussion.

Overall, these differences in study assumptions can substantially affect the planning reserve margins necessary to achieve the chosen reliability targets, as we illustrate further in Section III.B.2 below.

II. APPROACH TO MODELING THE ECONOMICS OF RESOURCE ADEQUACY

To examine the economic implications of the 1-in-10 resource adequacy standard, we conduct a series of reliability simulations using the SERVM model developed by *Astrape Consulting*.[40] In this section, we provide an overview of our simulation approach, including a description of the SERVM model, the characteristics of the hypothetical system we examine, and our key modeling assumptions.

We simulate a hypothetical RTO system that is interconnected to three neighboring systems. This hypothetical RTO is not intended to represent any actual system, but has characteristics similar to those of many U.S. markets. For example, we assume that the Study RTO's resource mix is similar to that of NYISO, while the weather and wind profiles are similar to those in the TVA region. The resource mix, weather, and wind profiles of Neighbors 1, 2, and 3 are similar to those of MISO, PJM, and SoCo. We model both reliability and economic outcomes for the Study RTO in 2016 as the assumed delivery year, as forecasted from a 2013 resource planning year. We describe our modeling approach and assumptions in this section and provide additional detail in Appendix B.

A. STRATEGIC ENERGY RISK VALUATION MODEL OVERVIEW

We use the Strategic Energy Risk Valuation Model (SERVM) to study the reliability and economic implications of the 1-in-10 standard and alternative resource adequacy standards. Like other reliability modeling tools, SERVM probabilistically evaluates resource adequacy conditions by simulating generation availability, load profiles, load uncertainty, transmission availability, and other factors. Based on these reliability simulations, SERVM estimates standard reliability metrics including LOLE, LOLH, and EUE. Unlike other reliability modeling packages, however, SERVM also simulates economic outcomes including hourly generation dispatch, import-export dynamics, ancillary services, emergency procedures, and investment costs. SERVM estimates hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins as a function of planning reserve

[40] The SERVM package was originally developed by SoCo in the 1980s to support resource adequacy decisions and significant resources have been devoted to develop the model since then in a number of applications by various companies. Today, SERVM is managed by *Astrape Consulting*, who provides consulting services and licenses of SERVM to inform resource adequacy decisions to a number of clients, including LG&E, KU, SoCo, TVA, CleCo, SCANA, Duke Energy, Progress Energy, and Terna (the Italian system operator).

margins. These results allow us to compare these variable costs against the incremental capital costs required to achieve the higher planning reserve margins.[41]

The multi-area economic and reliability simulations in SERVM include an hourly chronological economic dispatch that is subject to inter-regional transmission constraints. Each generation unit is modeled individually, characterized by its own economic and physical characteristics. Planned outages are scheduled in off-peak seasons to minimize the impact on reliability, while unplanned outages and derates occur stochastically using historical distributions of time between failures and time to repair. Load, hydro, wind, and solar conditions are modeled based on profiles consistent with individual historical weather years. Dispatch limitations and limitations on annual energy output are also imposed on certain types of resources such as demand response, hydro generation, pumped storage, and environmentally-limited combustion turbines (CTs).

The model implements a weekly commitment algorithm in each study region that considers the outlook for weather and planned generation outages. The model then conducts an hourly economic dispatch of baseload, intermediate, and peaking resources, including an optimization of transmission-constrained inter-regional power flows to minimize total cost. Pumped storage resources are dispatched economically to capture differences in pricing between peak and off-peak periods. During most hours, hourly prices in each region reflect marginal production costs, with importing regions realizing higher prices when import constraints are binding. During emergency and other peaking conditions, SERVM simulates scarcity prices that exceed generators' marginal production costs as explained further below.

To examine a full range of potential economic and reliability outcomes, SERVM conducts a Monte Carlo analysis over a large number of scenarios varying with both demand and supply conditions. Because reliability events occur only when system conditions that reflect unusually high loads or limited supply, these simulations must capture wide distributions of possible weather, load growth, and generation performance scenarios. In this study, we incorporate 32 weather years, 6 economic load forecast error points, and 50 draws of generating unit performance for a total of 9,600 scenarios for each simulated reserve margin case, with each scenario simulating all 8,760 hours of the year.[42] This large number of simulations is necessary for accurately characterizing the reliability and economic implications of different planning reserve margins because the vast majority of reliability-related costs are incurred within a small

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[41] Note that SERVM as a modeling tool does not endogenously estimate capital costs, which are reflected as a fixed annual cost (in $/kW-year). Total capacity costs simply increase as a function of the planning reserve margin being evaluated. The question of whether a particular reserve margin is actually achievable or realistic under various market designs, including in regions with capacity markets, energy-only markets, or cost-of-service regulation, depends on whether those markets have been constructed such that investors are able to recover their fixed costs at that reserve margin. We examine these and other market design implications of our modeling exercise in Section IV below.

[42] Note that SERVM results incorporate this set of scenarios for each reserve margin level simulated for the base case and each alternative case we present in this report. Depending on data availability and study needs, SERVM can incorporate any number of weather, hydro, wind, solar, economic forecast, and other scenarios. For the purpose of this study and to facilitate exploration of a larger number of alternative cases, we streamlined the simulation effort by modeling only 50 draws of generation outage conditions. In other studies, *Astrape* typically models several hundred generation outage draws.

number of simulation runs (or, in real-world systems, in a small number of infrequent emergency events). Such reliability events are typically triggered by rare circumstances that reflect a combination of extreme weather-related loads, high load-growth forecast error, and unusual combinations of generation outages.

To properly capture the magnitude and impact of reliability conditions during extreme events, a critical aspect of this modeling exercise the economic and operational characterization of emergency procedures. For this reason, SERVM simulates a range of detailed emergency procedures, accounting for energy and call-hour limitations, dispatch prices, voltage reductions, operating reserve depletion, dispatch of economic and emergency demand-response resources, and administrative scarcity pricing.

B. System Topology and Transmission Assumptions

We evaluate the economic reliability implications of resource adequacy by analyzing a hypothetical RTO interconnected to three adjacent systems. This hypothetical RTO has system characteristics similar to those of many U.S. markets, but does not exactly reflect any one region in particular. By constructing such a generic system as a Base Case and comparing those results to a series of Change Cases, we are able to examine our results under a variety of realistic resource mixes, load profiles, market structures, and economic assumptions. This allows us to draw conclusions that are relevant to a number of real-world systems without narrowing our focus to any individual real-world system. As summarized in Figure 3, the Study RTO is a 50,000 MW system interconnected with three similarly-sized regions.

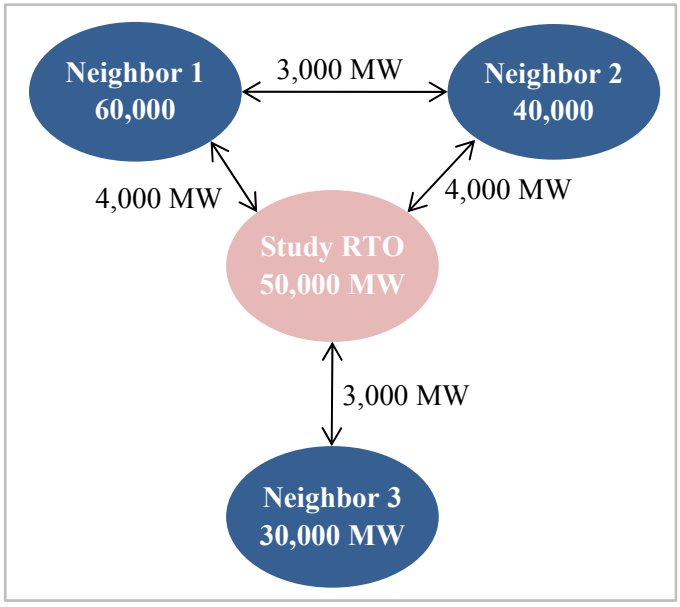
The transmission capabilities shown in the figure represent the maximum import and export capabilities of the interties, which vary stochastically over a distribution between 60% and 100% of the maximum. As we explain further in Appendix B.1, the maximum simultaneous import capability to the study region is 11,000 MW but drops to below 8,000 MW in 50% of all hours.[43] We assume that no portion of the interties' transfer capability is dedicated to the firm import of external resources committed towards resource adequacy of the Study RTO.[44]

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[43] We statistically represent the variable availability of inter-regional transmission capability, but do not explicitly model the various reasons that interties may be partly unavailable at different times. However, we note that some of these factors include line outages, path ratings that may vary with temperature or operating procedures that sometimes limit imports to avoid great exposure to single large contingencies.

[44] In real-world systems, it is important to distinguish the portion of each intertie that is dedicated to firm capacity imports under firm Point-to-Point (PtP) transmission from the remaining portion of the interties that can assist internal resource adequacy on a non-firm basis as long as the neighboring system's resources exceed the needs of their native load. For our purposes we treat all external resources as being available to the Study RTO on a non-firm basis driven by economics, but assume that in emergency events each system will have first call on their internal generating resources. We discuss these topics further in Section III.B.2 below.

Figure 3
Transmission Topology and Non-Coincident Peak Loads



Notes:
Stated intertie ratings represent the path maximum.
See Appendix B.1 for additional detail on intertie availability.

C. Resource Assumptions

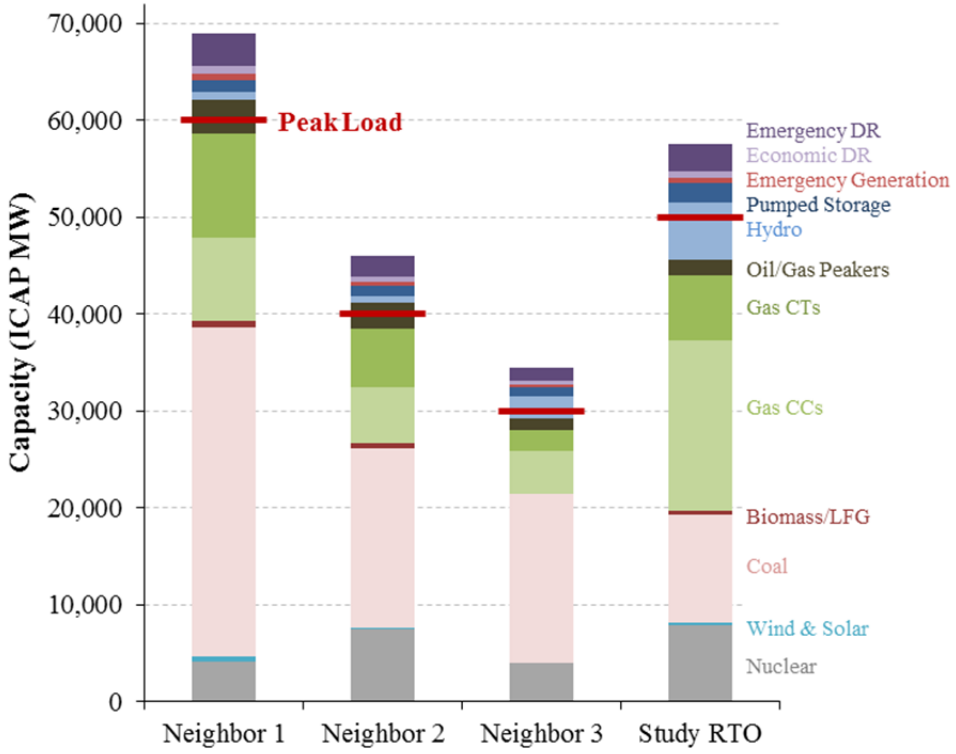
To characterize the generation and demand response resources available to meet load the simulated Study RTO and the neighboring regions, we assume resource characteristics consistent with many real-world systems. We present here a description of our assumptions and approach to modeling system supply, including each region's resource mix, supply curves, generation resource availability, and demand response resources.

1. Resource Mix

Figure 4 summarizes the supply resource mix in the Study RTO and the neighboring systems, with the Study RTO represented at the 15% reserve margin. We model each system with a reasonable proportion of baseload, intermediate, and peaking resources. Each region also has some energy-limited and intermittent resources such as hydro, pumped storage, wind, solar, and emergency demand response. Some characteristics of the Study RTO that materially impact study results include that: (1) the Study RTO depends more heavily on natural-gas-fired plants while the neighboring regions have more coal, meaning that the Study RTO will tend to be a net importer at the assumed natural gas and coal prices; (2) the 10% hydro penetration in the Study Region is higher than in neighboring regions, adding some additional uncertainty into the Study RTO's resource availability; and (3) assumed DR penetration is 6-7% of peak load depending on

the region, which is consistent with many current markets but below the penetration levels expected in coming years in some of the eastern RTOs, such as PJM and ISO-NE.[45]

Figure 4
Installed Capacity and Resource Mix



Notes:
All regions shown at 15% planning reserve margin, although simulated reserve margins vary by model scenario.
Wind and solar shown at capacity credits of 15% and 25% respectively, which is the same as their contribution to the reserve margin (other resources are represented at nameplate)

We assume a planning reserve margin of 15% is maintained in all neighboring regions, similar to the current reserve margin targets in a number of actual North American markets. We calculate reserve margins based on nameplate capacity for all resource types except for wind and solar, to which we assign capacity value at 15% and 25% of nameplate, respectively. Economic and emergency demand response capacity are included on the supply side in the reserve margin calculation.[46] The load impact of voltage reduction is not considered in the reserve margin

[45] For example an ISO/RTO Council Study estimated a 6.6% overall DR penetration level across all North American RTOs as of 2008, while PJM and ISO-NE's capacity auctions for 2015/16 and 2016/17 cleared DR commitments equal to 9.9% and 9.3% of peak load respectively. See IRC (2009), p. 26; PJM (2013a); and ISO-NE (2013).

[46] Section II.C.4 explains our approach to modeling economic and emergency DR, including a description of how we distinguish these two resource types from a modeling perspective.

calculation, but we do implement voltage reductions to avoid shedding load in our simulations as discussed in Section II.E.

2. Energy Market Supply Curve

In modeling production costs for each supply resource, we assume plant costs and efficiencies that are typical for each resource type and that vary among individual units. The aggregate system supply curves for each region are shown in Figure 5 and account for fuel costs and variable operations and maintenance (VOM) costs. [47] We assume delivered fuel costs as projected for the year 2016 in the *Annual Energy Outlook*, with coal at $2.50/MMbtu, natural gas at $5/MMbtu, and fuel oil at $25/MMbtu.[48]

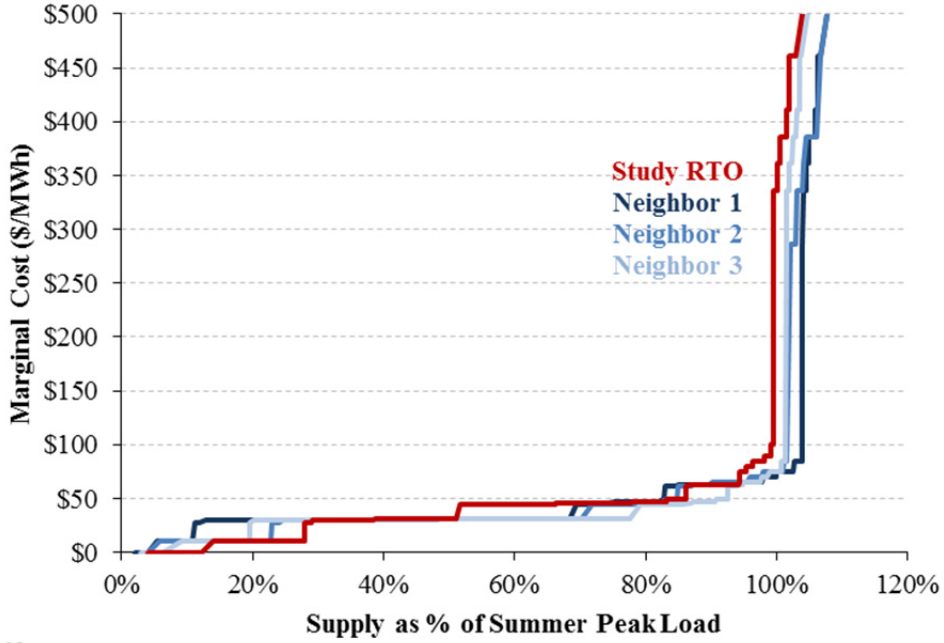
As Figure 5 shows, the Study RTO's supply stack is similar to, but not identical to, those of its neighbors. Over most of the relevant dispatch ranges from 50% to 100% of peak load, the Study Region's available supply from natural gas combined cycles (CCs) is slightly more expensive than supply from the neighboring regions that have a higher share of lower-cost coal resources. At the very top of the supply stack shown in Figure 5, the Study RTO supply curve is also higher because it depends somewhat more heavily on high-dispatch-cost demand response resources and emergency hydro for super-peaking periods, while the neighboring regions have more peaking gas and oil units. The highest-price portion of the supply curve at dispatch costs above $500/MWh is not shown in this figure, but causes the Study RTO supply curve to rise sooner because it is shown as a percentage of peak load. We more fully describe the emergency procedures, economic costs, and energy pricing mechanisms assumed during high-price events in Section II.E below.

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[47] While SERVM also has the capability to model a host of other unit parameters including startup and shutdown costs, minimum up and down times, emissions costs, and heatrate curves, we exclude these parameters from our study for simplicity.

[48] Specifically, we use average national prices as-delivered to the electric power sector from the High Economic Growth case in the 2012 *Annual Energy Outlook*. Fuel prices reported in nominal dollars, see EIA (2012).

Figure 5
Energy Market Supply Curve by Region



Notes:
Wind and solar capacity derated to 15% and 25% of nameplate.
Pumped storage represented at a $0/MWh, although dispatched only at daily peak.
$2,000/MWh emergency DR and $3,000/MWh emergency hydro not shown due to scale.

3. Generation Outage and Availability Modeling

A major component of reliability analyses is modeling the availability of supply resources after considering planned outages, forced outages, intermittency, and energy limitations. We use SERVM to simulate generation resource availability on a unit-specific basis, but characterize resource utilization and availability differently depending on resource type:

Thermal Resource Outages – We assume planned and forced outage rates for thermal generation resources based on unit type and size, consistent with recent NERC data from the Generation Availability Data System (GADS).[49] SERVM schedules planned outages during low-demand periods in the spring and fall, but models maintenance and forced outages stochastically. Partial and full forced outages occur stochastically for each individual unit based on probability distributions accounting for time-to-fail, time-to-repair, and partial outage derate percentages. Similarly, SERVM models the need for maintenance outages stochastically, but implements these outages with some scheduling flexibility during off-peak hours to the extent feasible. This outage modeling approach allows SERVM to capture the potential for severe shortages caused by a number of coincident outages.[50] Appendix B.2 contains additional detail describing forced and maintenance outage modeling.

[49] See NERC (2011b).

[50] Capturing the possibility of such low-probability, high-impact events is an advantage of the unit-specific Monte Carlo outage modeling used in SERVM. Other production cost and reliability models typically use

Continued on next page

Hydroelectric Availability – We model 30 years of hydro resource availability using monthly hydro generation data for the respective regions and historical years used in our load modeling described in Section II.D.1 below.[51] These hydro resources have varying levels of flexibility as either run-of-river plants with a fixed schedule, peak shaving plants that are dispatched based on the difference between peak and off peak prices, or emergency hydro capacity dispatchable at $3,000/MWh. See Appendix B.3 for additional detail on hydro resource modeling.

Pumped Storage – We characterize pumped storage resources according to reservoir size, pumping efficiency, and capacity and dispatch these resources to maximize their economic value assuming imperfect foresight of hourly energy prices.[52] The units pump during off-peak hours and generate during on-peak hours, but only when the anticipated price differential is large enough to overcome pumping efficiency losses.

Intermittent Resources – We model intermittent wind and photovoltaic solar resources assuming non-dispatchable hourly generation profiles for the Study RTO's modest penetration levels of 3.8% and 0.09% for wind and solar respectively in the Base Case.[53] For wind generation, the hourly profiles reflect three years of data from the *Eastern Wind Integration Transmission Study* (EWITS); for solar they reflect one year of data from *PV Watts*.[54] In both cases, the hourly profiles are consistent with the weather data for the four regions used in our load modeling. To capture intermittent resource availability as well as inter-regional weather correlations, SERVM randomly draws a particular day within the month being simulated and uses hourly profiles from that same date for each modeled region. See Appendix B.4 for additional detail on our intermittent resource assumptions.

After SERVM accounts for all of these factors, the model determines the aggregate quantity of resources available for economic dispatch as described in Section II.A above.

4. Economic and Emergency Demand Response Resources

Most regions have a variety of DR programs that can be dispatched whenever a certain price or reliability event occurs.[55] While the nuances of each variety of DR program could be modeled in SERVM consistent with a region's actual DR portfolio, we focus on simulating two broad categories of DR programs:

Continued from previous page

a simpler convolution method, resulting in a distribution of outages that may under-estimate the potential for extreme events, especially in small systems.

51 Monthly hydro data for each region obtained from EIA (2013a).

52 Specifically, to reflect the scheduling activity of a pumped hydro resource with slightly imperfect foresight of actual market prices in each hour, we implement this hourly scheduling using a price profile from the same date from a different run of SERVM with the same load profile but with different outages.

53 These penetration levels are calculated as nameplate as percent of summer peak load.

54 ETWITS and PV Watts are both developed by the National Renewable Energy Laboratory, see NREL (2013a-b).

55 For a survey of various types of demand response programs, see the summary and referenced supporting documentation in IRC (2009), Section IV and IRC (2010).

Emergency DR – The majority of existing RTO-dispatchable DR programs would be most accurately described as "emergency" or "capacity-only" resources. Emergency DR programs contribute to resource adequacy and increase planning reserve margins because they can be dispatched during reliability events. These resources will not dispatched on an economic basis, but will be triggered during emergency conditions according to the system operator's emergency procedures as explained in Section II.E below. We assume that these DR resources have a curtailment cost of $2,000/MWh and a 100 hour-per-year maximum dispatch limit.[56]

Economic DR – A minority of existing RTO-dispatchable DR programs are what we classify as "economic" DR resources. These resources bid into the energy market at a resource-specific strike price that reflects the customer's willingness to pay for energy. Whenever wholesale energy market prices exceed this strike price, the resources would be dispatched just like a generator that offered into the market at the same offer price. Economic DR resources also contribute to planning reserve margins, but we assume they do not have any limit on the annual call hours. We simulate a supply curve of economic DR resources with strike prices ranging from $100 to $1,000/MWh in the Base Case and over a wider range of strike prices up to the price cap of $7,500/MWh in a high economic DR penetration case as explained further below.[57]

Our Base Case simulations assume DR penetration levels of 6-7% of peak load across the different regions as shown in Table 3, consistent with the penetrations in many actual systems today.[58] We further assume for all regions that 80% of the DR resources are emergency DR while 20% are economic DR programs.[59]

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[56] It is standard practice among many systems to have "emergency" or "capacity" DR programs that are triggered by emergency conditions rather than based on energy market prices. Many of these programs also have call-hour or other types of restrictions that limit their total annual use, but there is no standard call-hour limitation and so our 100 hour limit is somewhat arbitrary. For example, PJM's limited DR product can be called only in summer peak periods for up to 10 calls and up to 6 hours per call. The per-call cost of these programs is also relatively arbitrary, and so we assume an interruption cost that is consistent with the price cap applicable in some markets that implement these programs as well as the order in which these emergency resources are called as discussed further in Section II.E. See IRC (2010).

[57] Economic DR suppliers may offer at any strike price of their own choosing, but at a price that reflects the underlying customer's willingness to pay for energy. We assume an offer price range of $100-$1000/MWh in the Base Case, reflecting the assumption that economic DR would typically bid only at prices above the average retail price for energy. We also evaluate an alternative scenario with substantially more economic DR, as explained further below and illustrated in Figure 6.

[58] For example, see IRC (2009), p. 26.

[59] This ratio of emergency DR to economic DR is based on the current proportion in PJM, see PJM (2013c), p. 5.

Table 3
Base Case Demand Response Penetration

Region	Demand Response Capacity		Total DR
	Emergency *(MW)*	Economic *(MW)*	Penetration *(% of Peak Load)*
Study RTO	2,778	694	6.9%
Neighbor 1	3,380	845	7.0%
Neighbor 2	2,132	533	6.7%
Neighbor 3	1,424	356	5.9%

Notes:
Base Case DR penetration levels are consistent with levels currently achieved in many real-world RTOs, see IRC (2009), p. 26,

We simulate a series of alternative DR cases to evaluate the implications of growing levels of DR penetration. The consequences of relying more heavily on DR for resource adequacy purposes will be particularly important over the coming years in PJM, which has attracted large quantities of DR commitments through its forward capacity market, amounting to 9.9% of normalized peak load by 2015/16.[60]

At PJM's high historical reserve margins, increasing quantities of DR would not be expected to substantially impact PJM's energy market pricing or reliability outcomes. This is because the "generation-only" reserve margin was high enough to meet the reliability target even without any DR commitments. This will change in the coming years, however, because the large increase in DR penetration is also enabling the retirement of a large quantity of uneconomic generation resources.[61] Displacing generation with DR resources has substantial implications, because the "generation-only" reserve margin will soon be far below the reliability target. This means that DR resources will have to be dispatched more frequently. It appears likely that this combination of factors will: (a) cause dispatch-limited DR to have a somewhat lower reliability value, a concern that PJM has already addressed by introducing multiple DR products; (b) require DR suppliers to reevaluate their willingness to sell capacity at a particular price; (c) result in higher energy market prices during scarcity events; and (d) motivate more DR resources to participate as "economic" rather than "emergency" resources.[62]

We evaluate the consequences of high levels of DR penetration in two alternative scenarios. We begin with a no-DR case in which all DR is removed from the Study RTO, and with total generation resources sufficient to maintain a 15% reserve margin. We then evaluate the consequences of displacing generation with DR by removing gas CTs and replacing them with

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60 See PJM (2013a).

61 For additional documentation of these displacement quantities, see PJM (2013a); Newell and Spees (2013); and Spees, *et al.* (2013).

62 See additional discussion of these topics in Sections III.C and IV.C below as well as Newell and Spees (2013) and Spees, *et al.* (2013). For an explanation and discussion of PJM's multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

either: (1) Emergency DR in one scenario; or (2) Economic DR in a second scenario. In both the Emergency and Economic DR cases, we model DR penetration levels of 0%, 5%, 10%, and 20% of peak load while maintaining a 15% reserve margin across all runs.

We assume that Emergency DR has the same characteristics as in the Base Case, with a $2,000/MWh dispatch cost and a 100 hour dispatch limit (although we also test the impact of varying the dispatch limit). We model Economic DR differently, however, with Economic DR resources offering over a wide range of prices up to the price cap of $7,500/MWh, as shown in Figure 6. This Economic DR supply curve is based on available evidence of how responsive customers could be to high energy market prices, but required us to make additional assumptions about how customers would behave at penetration levels that are far above historical experience.[63] To create this economic DR supply curve, we assume that the aggregate customer base has a constant elasticity of demand, and adjust this elasticity to achieve the 5% to 20% total economic DR quantity up to the energy market maximum price of $7,500/MWh.[64] The shape of this economic DR supply curve is generally consistent with the results of various real-time and critical-peak-period pricing experiments, although those experiments are more often centered on estimating peak load reductions or on-peak versus off-peak elasticities of substitution.[65]

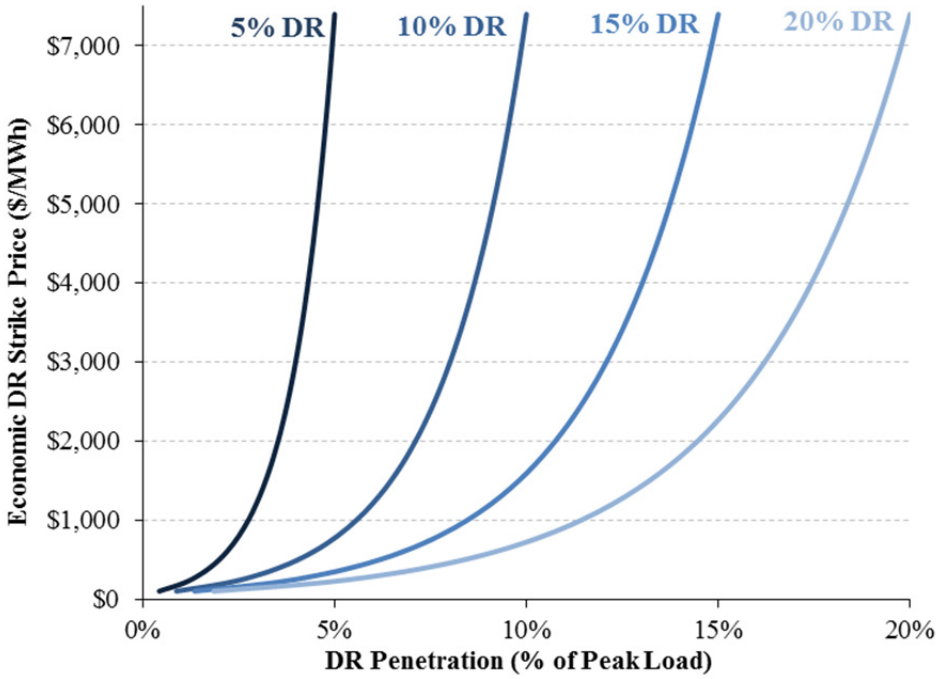
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[63] For example, in PJM, economic DR offers in the energy market are only approximately 1.4% of summer peak load, see PJM (2013c), p. 5.

[64] More specifically, we assume that customers are represented by the formula $Q = a \cdot P^E$, where: Q is weather-normalized peak load; a is a constant; and P is the customer-realized electricity price including energy (at $57/MWh on average at the 15% reserve margin as calculated in the Base Case), capacity (at $9/MWh at the 15% reserve margin as calculated in the Base Case), and transmission and distribution (T&D) charges (at $34/MWh), consistent with the national average. We calculate the parameters a and E, assuming that peak load would be at the normalized (50/50) forecast (consistent with the annual average energy price), reduced by the total DR penetration percentage at the maximum energy market price of $7,500/MWh. Average T&D charges are based on 2011 annual average charges of delivery-only electric providers averaged across all customer classes, see EIA (2013b).

[65] These economic DR supply curves are consistent with constant demand elasticities of -0.012, -0.024, -0.038, and -0.052 for the simulated 5%, 10%, 15%, and 20% DR penetration cases. These elasticities are generally consistent with estimates from various pilot studies of customer price-responsiveness to real-time and critical peak pricing programs, although those studies often estimate elasticities of substitution or simple peak reductions as a function of price or price ratio. See, for example, Faruqui and Sergici (2010, 2011, 2013).

Figure 6
Energy Market Supply Curve for Economic DR Penetration Case



Notes:
Calculated assuming constant demand elasticities of -0.012 to -0.052, see also Footnotes 64 and 65.

D. LOAD MODELING

Load uncertainty is a key factor driving reliability events. We separately account for the two primary drivers of load uncertainty: (1) weather, which varies from year to year over a wide range of hourly profiles; and (2) economic load forecasting uncertainty, which characterizes the uncertainty in load growth independently of weather.

1. Weather Uncertainty

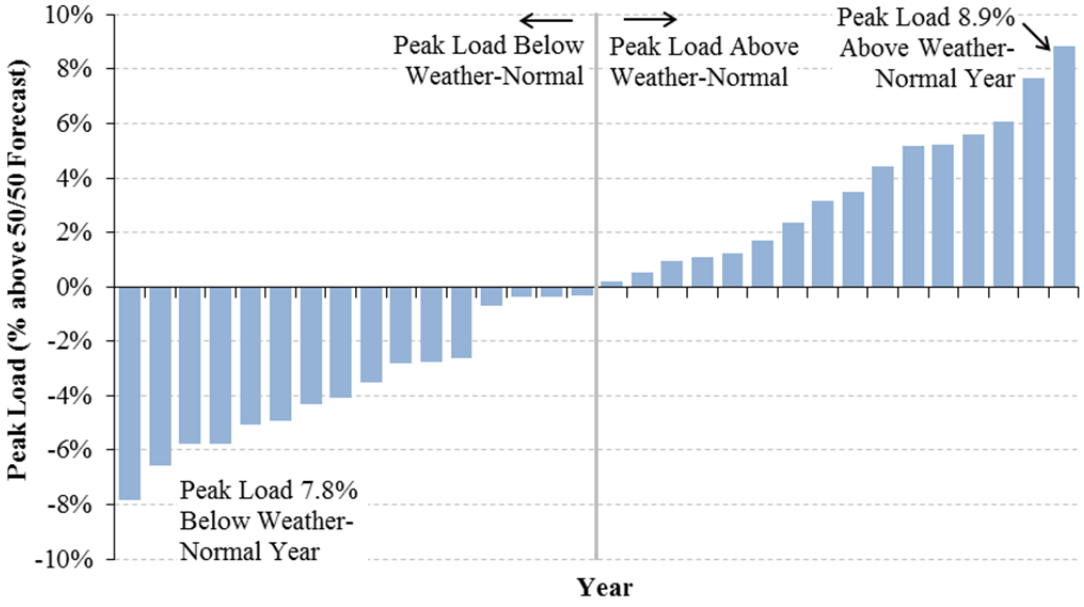
To characterize load uncertainty caused by weather, we use 32 years of historical hourly temperature and rainfall data and five years of historical hourly load data for each study region. Weather and load profiles in the Study RTO are based on data for TVA, while Neighbors 1 through 3 are based on central MISO, western PJM, and SoCo respectively.[66] We use the most recent five years of hourly weather and loads to develop a statistical relationship between load and weather, accounting for a number of variables including month of year, time of day, and day of week. We use this relationship to create 32 synthetic load profiles that are consistent with each of the 32 historical weather years. Figure 7 shows that the resulting peak loads range from -

[66] Hourly Historical Load Data for the Study RTO (based on TVA) and Neighbor 3 (based on SoCo) are derived from FERC 714 Forms. Load data for Neighbor 1 (based on central MISO) and Neighbor 2 (based on western PJM) are derived from RTO data. All hourly weather data are from the National Oceanic and Atmospheric Administration (NOAA). See FERC (2013); PJM (2013b); MISO (2013a); and NOAA (2013).

7.84% below to 8.85% above the weather-normalized peak load in the Study RTO. Each weather year also has a different overall load duration curve, with some years having sustained heat waves that cause a much larger number of high-demand hours.

By using weather profiles from the same historical years for each of the modeled regions, we are able to capture the inter-regional correlation in loads and level of load diversity on high-demand days. Since weather patterns can differ substantially across the four regions on summer days, the timing of each region's highest peak loads will be different as well. If one region is at its system peak load but a neighboring region is not, the load diversity between the two systems will reduce their combined resource needs. Overall, the load diversity across the four regions yields a coincident peak load of 174,668 MW compared to the sum of regional non-coincident peaks of 180,000 MW, or a 3% reduction due to load diversity. Appendix B.5 contains additional detail on weather uncertainty in load modeling.

Figure 7
Study RTO Summer Peak Load under Different Weather Profiles



Notes:
Range in peak load shown is due to weather uncertainty alone, without economic load growth forecasting error.

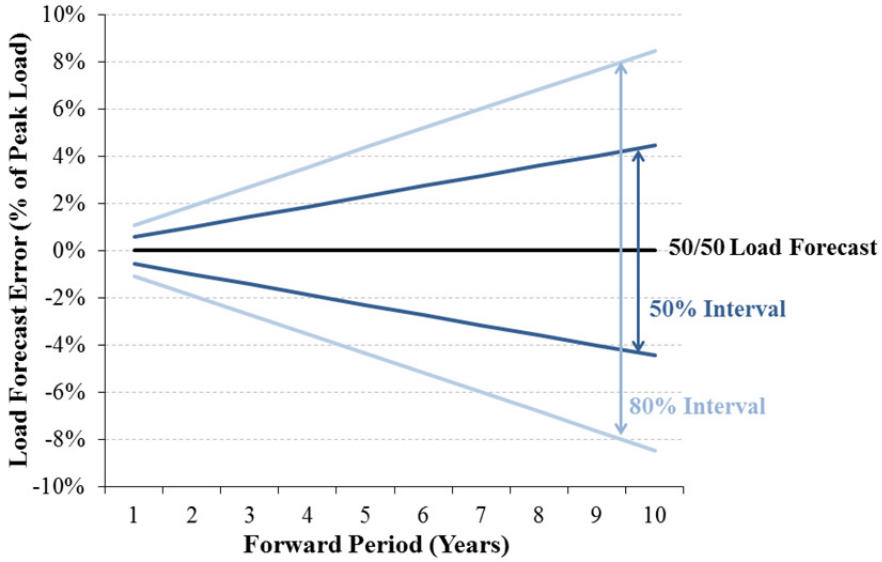
2. Economic Load Growth Forecasting Uncertainty

Load uncertainty is driven not only by year-to-year volatility in weather patterns, but also by an underlying load growth forecasting error over the forward study period. This is the level of uncertainty in 2016 peak load as would be forecast in 2013, even if the modeler were certain that 2016 would be a "weather normal" year. An important driver of that uncertainty for resource planning purposes is the uncertain outlook for economic growth. Unanticipated economic growth or downturns can result in peak loads that are substantially higher or lower than the forecast. Further, economic uncertainty increases with the forward planning period; this is unlike weather-based uncertainty, which is constant across all forward periods.

Figure 8 shows how the assumed level of the economic load growth forecasting error increases with the forward planning period. This assumed economic forecast error is based on the last 20 years of Congressional Budget Office (CBO) four-year forward forecasts of U.S. national real gross domestic product (GDP) growth compared to actual GDP growth.[67] We translate this economic growth uncertainty into load forecast uncertainty by assuming that electricity load will grow at 40% of the GDP growth rate, reflecting the approximate relationship between electric energy consumption and GDP growth over the period 1980 to 2010.[68]

Note that Figure 8 shows only the peak load forecasting error related to underlying economic uncertainties and excludes the portion of load uncertainty related to weather. The chart shows that, although peak load forecast error is zero on average, the spread in possible outcomes increases over time so that the 80% confidence interval for economic load growth forecasting errors increases from a spread of only 2.2% at one year forward, to 5.4% three years forward, and to 17% ten years forward. Note that increasing the forward planning period in a reliability analysis such as ours will translate into a higher likelihood of reliability events at any given reserve margin, and will therefore result in setting a higher reserve margin requirement.

Figure 8
Economic Load Forecast Error vs. Forward Planning Period



Notes:
Load forecast error is normally distributed around zero with a 0.8% standard deviation at one year forward, with standard deviation increasing 0.6% for each additional year.

In our Base Case simulation, we assume an economic load forecast error consistent with a four-year forward planning exercise. This assumption is consistent with many system operators' planning studies and is approximately consistent with the lead time for developing a new

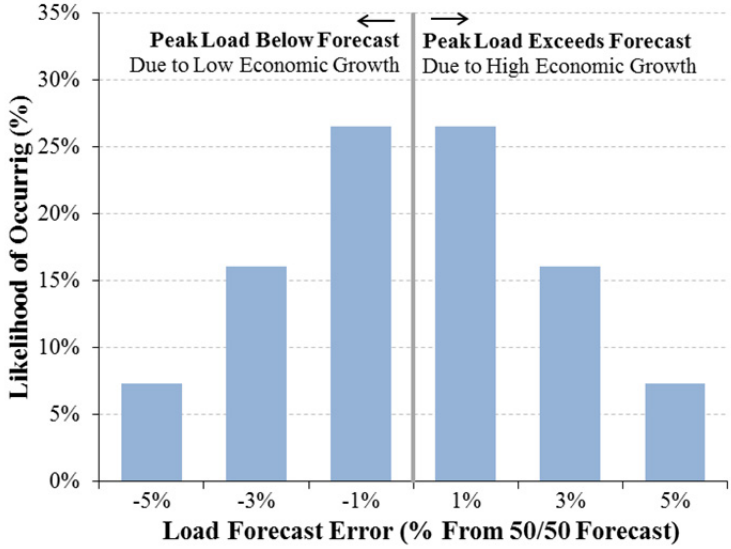
[67] See CBO (2012).

[68] During this 30-year period, electric energy consumption rose by 2% per year on average while GDP grew by approximately 5% per year, suggesting the relationship is approximately 0.4% load growth for every 1% of nominal GDP growth. See CRS (2012); Data360 (2013).

combustion turbine plant.[69] The choice of this forward period for our simulations implicitly assumes that all resource planning decisions are locked in on a four-year forward basis with no shorter-term flexibility from uprates, DR procurement, delayed retirements, or off-system power purchase agreements (PPAs). However, if there is some flexibility to procure a portion of supply on a shorter-term basis, then total system costs could be reduced by: (1) maintaining a lower reserve margin while meeting the same reliability requirement; and (2) capturing the option value of waiting to procure a portion of resources until after some of the economic forecast uncertainty has resolved. We more fully explain and examine the economic and reliability implications of the forward planning period in Section III.A.5 below.

We represent this four-year forward distribution using six discrete levels of economic load forecast error with each assigned a specific probability level as summarized in Figure 9. We apply this economic forecast error equally to the Study RTO and the four neighboring regions, assuming economic load growth uncertainty is perfectly correlated across the study regions.[70]

Figure 9
Probability of Various Levels of Economic Load Forecast Error



Notes:
Economic forecast error consistent with a four-year forward period.

E. SCARCITY CONDITIONS

To calculate production costs and market prices during most hours, SERVM uses hourly supply curves of available resources in each region. The higher the generation outages and load in a particular hour, the higher the marginal dispatch cost and market price as explained in

[69] Note that total lead times including development, siting, and permitting may be substantially longer, but these phases of development represent a relatively small component of total plant costs.

[70] While there will likely be at least some diversity of load forecasting error across the five regions, the use of U.S.-wide GDP growth forecast already captures at least some such diversity because forecast error for economic growth within a particular region generally exceeds that of the nation as a whole.

Section II.A above. However during scarcity conditions, when system demand plus operating reserves requirements approach or exceed available supply, system operators must implement a series of emergency procedures to maintain system stability. One critical aspect of our modeling exercise is simulating: (a) what emergency procedures are implemented at each level of scarcity including the most extreme cases when load must be shed as well as somewhat less severe scarcity events; (b) what system costs are imposed under each type of emergency event; and (c) what market prices would prevail during these events.

For the purposes of our simulations, we assume that prices will always be set at marginal system cost, including during scarcity events when emergency procedures must be implemented. We also assume that non-emergency dispatch and emergency procedures will be implemented in order of ascending marginal system costs, as described in Table 4. This series of emergency procedures is generally consistent with the emergency actions implemented by many system operators, but is not intended to exactly reflect any particular system.[71]

Generally, the marginal system costs and resulting market prices represented in Table 4 increase with the severity of a shortage event up to the maximum energy price at the average customer value of lost load.[72] In our Base Case, we assume that the value of lost load is $7,500/MWh, representing the approximate value that the average customer places on service interruptions during load shed events. Customers' VOLL is a highly uncertain parameter that has been estimated over a wide range. Most academic and industry studies estimate residential customers' VOLL at below $5,000/MWh, while industrial and commercial customers' VOLL can exceed $15,000/MWh on average. To demonstrate the impact of this assumption, we analyze the sensitivity of our modeling results to this parameter in Section III.D.

We assume that each system is also willing to implement some (but not all) of these procedures to benefit neighbors when those systems are experiencing higher-cost emergency events. Calling Emergency DR is the most costly emergency procedure that each system will implement to maintain exports, but exports will be curtailed if any costlier emergency procedures would be required. In other words, we assume that system operators will not be willing to dispatch emergency hydro, endure operating reserves shortages, implement voltage control, or shed internal load for the benefit of neighboring systems.

[71] For example see AESO (2012) or PJM (2013d).

[72] A rich literature exists demonstrating that VOLL is the efficient energy market price to impose in extreme shortage events during which load must be shed. For additional discussion, see Section IV.A.2 below.

Table 4
Marginal Costs and Prices by Resource Type and Emergency Procedure

Marginal Resource or Emergency Procedure	Description
Generation $0 to $460/MWh	During most hours, marginal system cost is the marginal dispatch cost of generation, ranging from $0/MWh (for wind and solar) to approximately $460 (for inefficient oil peakers), see Section II.C.2.
Economic DR $100 to $1,000/MWh	Economic DR has a marginal cost of $100-$1,000/MWh in the Base Case, or up to the price cap in a high DR case, see Section II.C.4.
Emergency Generation $500/MWh	We assume that all resources have an "economic maximum" capacity rating used under normal conditions, and an "emergency maximum" rating that is 1% higher.[73] Achieving this higher emergency output level imposes substantial maintenance costs, assumed at $500/MWh.
Emergency DR $2,000/MWh	Emergency DR is available for dispatch through the supply stack similarly to generation resources at a $2,000/MWh price, although these resources are limited to a total of 100 call hours per year as explained in Section II.C.4.
Emergency Hydro $3,000/MWh	Emergency hydro is peaking resource that is costly and use-limited, with the costs being driven by the opportunity cost of not saving these resources for another time as well as environmental and societal costs imposed if reservoir levels are depleted.
Operating Reserves Shortages $3,000 to $7,000/MWh	Depleting operating reserves imposes marginal system costs by exposing the market to greater contingency risks. We model marginal system cost consistent with the administrative scarcity pricing curve shown in Figure 10 below.
Voltage Reduction $7,000/MWh	We assume that load can be reduced by 1% if implementing a system-wide voltage reduction at a marginal cost of $7,000/MWh.[74]
Firm Load Shedding $7,500/MWh	The maximum price and marginal system cost is at the assumed VOLL of $7,500/MWh, based on a mid-range estimate of customer-specific VOLL, assuming that load-shed events are more focused on locations with non-critical loads and more residential (rather than commercial-industrial) areas of the system .

[73] Distinguishing between generators' economic and emergency maximum ratings is common, with the emergency maximum output being dispatched only during scarcity conditions. For example see AESO (2012), p. 6; PJM (2013d), p. 23.

[74] The costs imposed by this type of voltage curtailment have not been widely studied, although the costs of different types of voltage sag or power quality events have been evaluated in some studies. We assume a cost slightly below the VOLL, consistent with the economics implied by the fact that voltage reductions, if implemented at all, are typically invoked only after all other procedures as a last resort to avoiding firm load shed, for example see PJM (2013d), p. 14; Sullivan, *et al.* (2009); CEER (2010).

As explained in Table 4, most resources are functionally modeled as part of the supply stack, including resources such as economic DR, emergency generation, emergency DR, and emergency hydro. These resources are always available for dispatch, but they are available only at high strike prices and so are dispatched only under scarcity conditions. However, for the most extreme scarcity events when other emergency procedures must be implemented, prices are set according to the administrative scarcity pricing function described in Figure 10. The figure shows that the administrative price would be set as a function of the hourly supply cushion, equal to the total quantity of non-emergency and emergency resources available in the supply stack minus the hourly load.

Any time the hourly supply cushion (hourly supply stack minus load) drops below a 5% operating reserves target, the system operator will have to implement an emergency measure to maintain supply-demand balance. First, the system will endure an operating reserves shortage relative to the 5% target maintained under normal system conditions. Simulated prices increase as the size of the operating reserves shortage increases, according to the specified administrative scarcity function. However, under no circumstances can operating reserves be allowed to drop below the 2% minimum level that must be maintained for system security even during load shed events. This downward-sloping portion of the administrative scarcity pricing function operates similarly to the "operating reserves demand curves" and equivalent mechanisms implemented by several RTOs over recent years.[75] We assume that this administrative scarcity pricing curve reflects the marginal system cost imposed by operating reserve shortages. These marginal system costs can be quite high because depleting operating reserves increases the risk of load shed events and even cascading outages that could be triggered by generation or transmission contingencies or sudden changes in load or wind generation.[76]

Once operating reserves are at the minimum level of 2%, the system operator will implement: (a) a system-wide voltage reduction that is assumed to achieve a 1% reduction in load at a marginal system cost of $7,000/MWh; and finally, as a last resort, (b) curtailments of firm load at a marginal system cost of $7,500/MWh.[77]

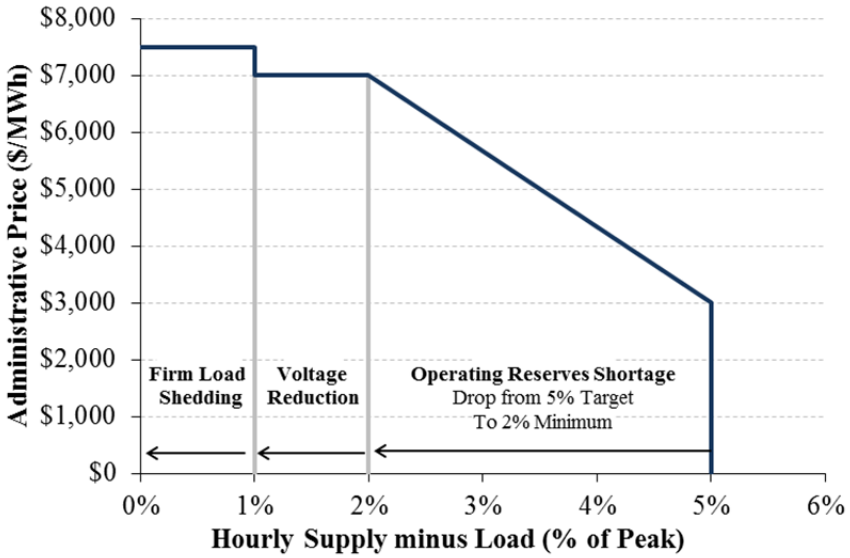
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[75] Examples of RTOs who implemented administrative scarcity pricing include MISO, PJM, and CAISO.

[76] For a more comprehensive discussion of how a system operator could estimate these marginal system costs for setting an operating reserves demand curve, see Newell, *et al.* (2012). Section V.A.3.

[77] Note that load must be shed when the supply cushion drops below 1% above hourly load. This is because: (a) actual load (after voltage reduction) will be hourly load minus 1%; and (b) the 2% operating reserves requirement must still be maintained.

Figure 10
Administrative Scarcity Pricing Function



Notes:
Horizontal axis of the administrative pricing curve is calculated as a percent of peak load and does not vary with system conditions.

F. MARGINAL RESOURCE COST AND PERFORMANCE

To examine economic and reliability outcomes over a range of reserve margins, we must increase or decrease installed capacity of a certain resource type. In our Base Case, we assume that the marginal technology is a natural-gas-fired combustion turbine (CT). We also examine an alternative case in which the marginal technology is a gas combined-cycle (CC) plant.[78] The incremental capital and fixed costs required to build and maintain an additional resource is measured as the levelized cost of new entry (CONE), and includes both: (a) annual fixed operations and maintenance (FOM) costs; and (b) the annual levelized capital costs of constructing a new plant. Table 5 summarizes our assumed CONE and heatrates for CT and CC plants, which are approximately consistent with current PJM parameters.[79] We examine the sensitivity of our results to our assumed CONE value in Section IV.B.3.

[78] See Section III.B.3.

[79] Actual plant costs could be anywhere over a substantial range. These reported costs are within the range of CONE values we estimated for different locations within PJM on a level-nominal basis for CT and CC plants with a 2015 online date. For a more precise report of construction costs and plant performance for a specific technology, see Spees, *et al.* (2011), pp. 2–3, 18.

Table 5
Assumed Cost and Performance of New Gas CT and CC Plants

	CONE *($/kW-yr)*	**Heatrate** *(btu/kWh)*
Combustion Turbine	$120	10,500
Combined Cycle	$150	7,000

Notes:
Approximately consistent with current PJM parameters, see Spees, *et al*. (2011), pp. 2-3, 18.

G. BASE CASE AND ALTERNATIVE SIMULATION CASES

To explore the reliability and economic implications of varying reserve margins, system configuration, and other study assumptions, we simulate the interconnected illustrative power system for a Base Case and test the sensitivity of our results to various assumptions. We also implement a number of Change Case simulations designed to evaluate the impact of system characteristics as summarized in Table 6 below. As shown, the alternative simulations test the impacts of: (1) lowering the energy market price cap; (2) assuming a smaller system size (with or without decreasing intertie capability); (3) increasing or decreasing the availability of neighbor assistance; (4) assuming that a CC rather than a CT is the marginal technology; (5) increasing wind penetration; and (6) increasing DR penetration.

Table 6
Summary of Simulation Cases

Simulation Case	Simulation Description
Base Case	- System assumptions as defined in Section II. - Vary Study RTO margin from 7% to 17% by adding gas CTs
Lower Price Caps	
$1,000 Price Cap Case	- Impose $1,000/MWh energy price cap in Study RTO and Neighbors
$3,000 Price Cap Case	- Impose $3,000/MWh energy price cap in Study RTO and Neighbors
Smaller System Size	
40% Size Case	- Study RTO size 40% of Base Case (20,000 MW peak load)
40% Size and Transmission	- Reduce Study RTO size to 40% of Base Case (20,000 MW peak load) - Reduce interties to 40% of Base Case (4,000 MW)
Neighbor Assistance	
Long Neighbors Case	- Increase Neighbors' reserve margins from 15% to 20%
50% Transmission Case	- Reduce Study RTO interties to 50% of Base Case (5,500 MW)
Island Case	- Eliminate Study RTO interconnections with neighbors
Marginal CC Case	- Add gas CCs to increase the Study RTO reserve margin from 7% to 17%
Wind Penetration Case	- Increase wind penetration up from 5% of peak load (at a 12% Study RTO reserve margin) up to 30% of peak load
DR Penetration	
Emergency DR Penetration	- Fix Study RTO reserve margin at 15% - Vary DR penetration from 0% to 20% of peak load by displacing CTs with Emergency DR (100 hours, $2,000/MWh strike price)
Economic DR Penetration	- Fix Study RTO reserve margin at 15% - Vary DR penetration from 0% to 20% of peak load by displacing CTs with Economic DR (unlimited call hours, strike prices from $0 to cap)

III. SIMULATED RELIABILITY LEVELS AND SYSTEM COST RESULTS

In this section, we report the results of a series of economic and reliability simulations for a hypothetical RTO with realistic attributes. We do not attempt to exactly replicate any particular real-world power system, but instead evaluate base and sensitivity case simulations that are generally illustrative of the economics of resource adequacy.

We first estimate the planning reserve margin needed to achieve different physical reliability standards such as 0.1 LOLE, 2.4 LOLH, and 0.001% Normalized EUE. We then compare those results to alternative standards based on economic criteria such as cost minimization and risk exposure. Finally, we evaluate the reliability and economic impacts of making different assumptions about system conditions, resource attributes, and transmission interconnection levels.

A. BASE CASE ECONOMIC AND RELIABILITY RESULTS

We present here the primary reliability and economic results from our Base Case analysis by: (a) comparing the reserve margins needed to achieve different reliability-based resource adequacy standards; (b) estimating the planning reserve margins that would minimize total system costs on a risk-neutral basis, defined from either a cost-of-service or a societal perspective; (c) discussing the risk mitigation benefits achieved by increasing the target planning reserve margin; and (d) evaluating the sensitivity of these economic results to study assumptions.

1. Reserve Margins Needed to Achieve Physical Reliability Standards

As explained in Section I.B.2 above, resource adequacy-related system reliability increases with reserve margin.[80] As a result, the frequency of outage events decreases at higher planning reserve margins. Figure 11 shows this on an installed capacity (ICAP) basis for our Study RTO.[81] The chart documents that, for our study RTO, the 1-in-10 standard translates to a 15.2% planning reserve margin target when defined as 0.1 LOLE, using a probability-weighted average of outage events across all scenario runs.[82] The figure also shows that even under identical

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[80] Recall that resource adequacy (*i.e.*, the extent to which physical supply exceeds anticipated load) accounts for only a small portion of end-use customer load-shed events, the majority of which are caused by smaller failures on the distribution system and to a lesser extent on the transmission system.

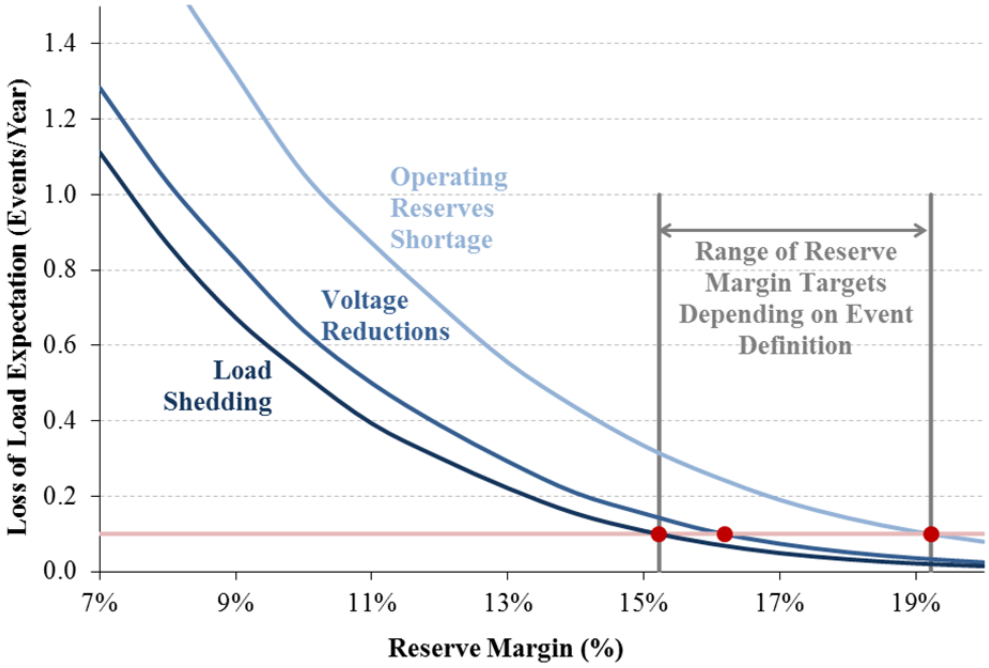
[81] In this figure and the entirety of this study, we calculate the reserve margin on an ICAP basis, assuming a capacity value 100% of nameplate capacity for all resources, including both economic and reliability DR, with the exception of renewable generation, which we assign capacity value of 15% of nameplate for wind and 25% for solar. We do not assign any capacity value to voltage reductions when calculating the reserve margin (to be consistent with most others' definitions), although we do not ignore the availability of voltage reductions for avoiding load shedding.

[82] Note that not all of the 9,600 runs that we simulate under each reserve margin are equally likely. We assume that any one of the 32 weather years and 50 draws on unit performance are equally likely, but the 6 different economic forecast error points are not equally likely with the more extreme over- or under-forecasts being less likely as explained in Section II.D.2 above. We account for these different likelihoods

Continued on next page

modeling and system assumptions, the target planning reserve margin ranges from 15.2% to 19.2%, depending on how "reliability events" are defined. In the remainder of this report, we treat events as contributing to LOLE only if firm load is shed, although some system operators define reliability "events" more broadly as discussed in Section I.C above. For example, the reserve margin requirement for 0.1 LOLE would be 16.2% if voltage reductions were considered reliability events or 19.2% if any depletion of operating reserves constituted an event.

Figure 11
Planning Reserve Margins for 0.1 LOLE with Different "Event" Definitions



Notes:
Study RTO in Base Case simulation results.

The target reserve margin also depends on which type of physical reliability standard we impose, even if one consistently defines reliability events as load-shed events. Figure 12 shows (from left to right) a planning reserve margin requirement of: (a) 15.2% when the 1-in-10 standard is defined as 0.1 LOLE (as it is in most U.S. regions); (b) 8.2% if the 1-in-10 standard is defined as 2.4 LOLH; or (c) 9.6% under the 0.001% Normalized EUE standard that is used in some international markets.[83]

This analysis shows that a 0.1 LOLE standard is a much more stringent reliability standard than 2.4 LOLH for the Study RTO, despite the fact that these two standards are both commonly referred to as "1 day in 10 years." The magnitude of the difference between the two standards

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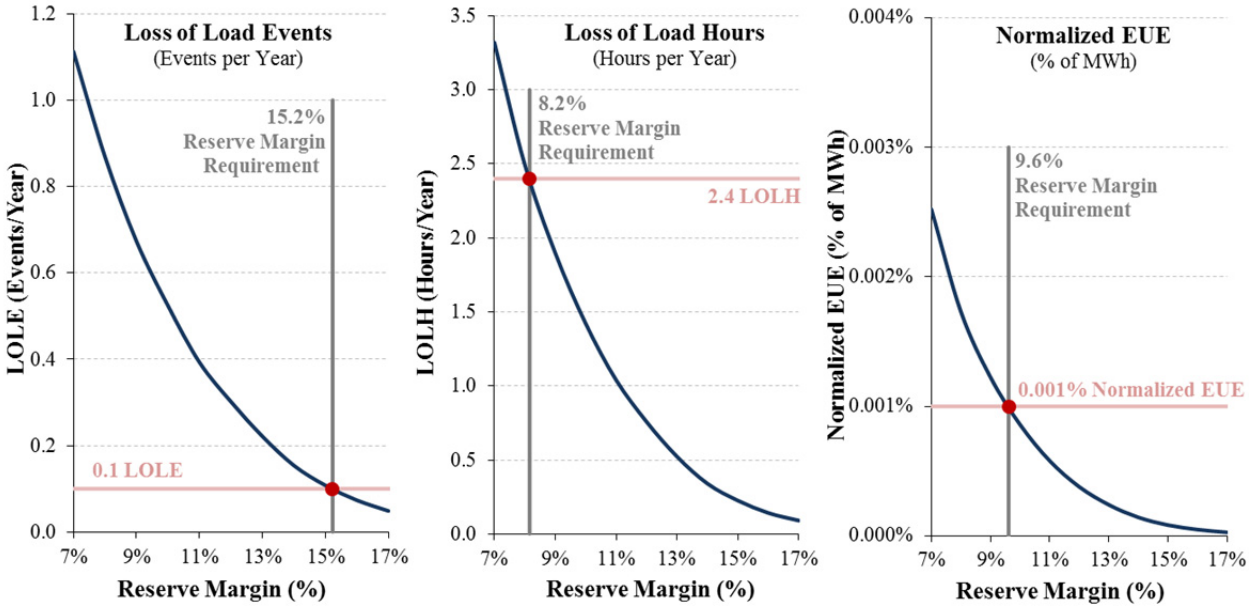
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when reporting average and percentile outcomes, although for simplicity we usually refer only to "average" results rather than "probability-weighted average" results.

[83] See additional discussion of these alternative reliability standards in Sections I.B.1and I.C above.

will not be the same in every system because it is driven by the average duration of the firm load shed event. For the Study RTO, the average duration of a single firm load shed event is typically only a small number of hours, which means accumulating 24 hours over ten years requires a number of individual outage events.

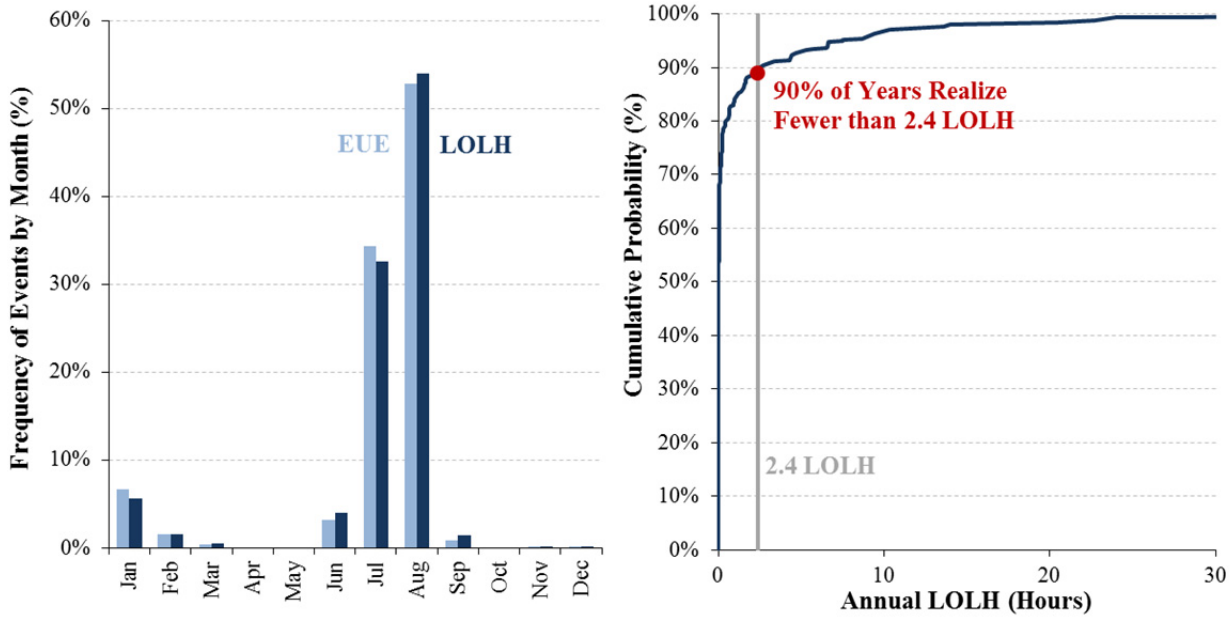
Figure 12
Planning Reserve Margins Required to Meet Different Physical Reliability Standards



Notes:
Study RTO Base Case simulation results.

The smooth and well-behaved appearance of these physical reliability metrics masks the substantial sensitivity to the underlying simulation assumptions and particularly to assumptions affecting extreme events. Although most reliability simulations consider thousands of scenarios, the value of the reliability metrics is usually driven by only a small number of extreme outage, weather, and load forecasting error scenarios, as illustrated in Figure 13. The chart shows the EUE and LOLH observed at a 10% reserve margin by month of year (on the left), and cumulatively for all 9,600 simulated years (on the right). As in all summer-peaking systems, our hypothetical RTO realizes nearly all outage events during the summer peak months. The importance of extreme events is highlighted even more by the right-hand chart, which shows that 45% of all simulated years have no outages, while the single worst simulation shows 68 load shed hours in the year. While only 10% of years exceed the 2.4 LOLH threshold, the probability-weighted average over all cases is 1.4 LOLH.

Figure 13
Distribution of Loss of Load Hours at 12% Planning Reserve Margin
Across Months (Left) and Across Simulation Years (Right)



Notes:
Distribution of realized EUE and LOLH in the Study RTO Base Case at 10% planning reserve margin.

2. Minimizing Cost from a Risk-Neutral, Cost-of-Service Perspective

As discussed in Section I.B.3 above, utilities and regulators in some regions use economic rather than reliability criteria to determine target reserve margins. Broadly speaking, these economic analyses aim to minimize total system costs by determining the "economically optimal" reserve margin. Such an economic analysis weighs the tradeoff between: (a) increasing capital and fixed costs associated with adding capacity to the system; and (b) decreasing reliability-related costs incurred during scarcity events, such as interrupting load, dispatching high-cost resources, procuring high-cost imports, and so on.

Accurately modeling or even defining some of these reliability-related costs is a challenging exercise. The exercise is further complicated by the fact that the cost-minimizing reserve margin is different depending upon the perspective from which costs are to be minimized. Some of the important questions to answer are:

- Is the objective to minimize societal costs, including all fixed and variable costs, regardless of whether those costs will be passed along to customers? Or, alternately, to minimize customer costs after evaluating how various costs will ultimately impact customer in their bills and realized outage rates?
- Should one consider only costs within the study region or also the costs imposed on external regions by relying on imports during scarcity events?

- If minimizing customer costs is the objective, is it from the perspective of a cost-of-service-regulated utility or the cost of serving customers in a competitive retail market?[84] Further, how do the costs of imports and revenues from exports affect customer costs within the Study RTO?
- Are costs to be minimized on a risk-neutral basis, which assumes that customers and regulators only care about the lowest average costs but not the proportion of costs introduced by extreme events? Or is it appropriate to assume some risk aversion and therefore ascribe an insurance value to avoiding high-cost events?

Depending on the perspective applied to a particular economic reliability study, choices implicit in each of these questions would yield a different planning reserve margin. For the purpose of our study, we first evaluate the economics of resource adequacy from a risk-neutral cost-of-service perspective. In this context, the objective is to minimize the expected cost of service within the Study RTO while ignoring any economic or reliability costs imposed on neighboring regions. We then examine the same reliability and economic questions from a societal cost perspective in the following Section III.A.3. Finally, Section III.A.4 explores how risk mitigation objectives could affect the planning reserve margin target, because higher reserve margins will substantially reduce the magnitude and likelihood of extreme events.

To estimate the risk-neutral, "economically optimal" reserve margin, we simulate realized reliability costs over a range of reserve margins as summarized in Figure 14. We vary the Study RTO planning reserve margins by adding or subtracting CTs as the marginal resource.[85] The Study RTO's total reliability-related costs for the Base Case, defined from this cost-of-service perspective, include:

Marginal Unit Carrying Costs – Fixed costs and annualized capital costs incurred by adding incremental capacity, assuming that the marginal resource is a CT with a CONE of $120/kW-year.[86] We do not report fixed costs associated with the existing generation fleet because these costs do not vary with reserve margin.

Marginal Unit Production Costs – Production costs associated with dispatching the added new CTs. These are the incremental production costs incurred to displace higher-cost existing resources, higher-cost imports, and higher-cost emergency procedures.

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[84] In a competitive retail market environment, adopting the objective of minimizing customer costs may be inappropriate in some circumstances, particularly where doing so would tacitly condone suppression of market prices. Note, however, that minimizing customer costs and minimizing societal costs are equivalent under the idealized case in which all internal and external markets are perfectly competitive, efficiently designed, and in a long-term equilibrium.

[85] We make alternative marginal resource assumptions in Section III.B.3 below, where we examine the impacts of adding or subtracting CCs instead of CTs.

[86] As explained in Section II.F above, this capital cost is within the range of level-nominal CONE values estimated for different regions in PJM for a CT with an online date in 2015, see Spees, *et al.* (2011), pp. 2-3 and 18. Section IV.B.3 below shows the sensitivity of the economic reserve margin to a range of CONE assumptions.

Net Import Costs – Total costs of purchasing imports net of any revenues from exporting power.[87] This treatment of imports and exports is consistent with how cost-of-service regulated utilities will typically evaluate net import costs.[88] It is also consistent with the Adjusted Production Costs (APC) metric commonly used within RTO systems for production cost analyses and transmission benefit-cost studies.[89] Note that this approach to tabulating import costs results in incorporating price suppression as a benefit, because displacing imports through new CTs during scarcity conditions will not only reduce the quantity of imports but will also reduce the price paid for all other imports. The price-suppression component of reduced import costs would not be considered a benefit if evaluated from a broader "societal" perspective as discussed further below.

Peaker Production Costs – Production costs associated with dispatching peaking resources that have higher operating costs than the marginal CT plants added to the system. Note that we would arrive at the same study results if we considered total system production costs, but the much larger total costs would make visual representation of the results more difficult.[90]

Emergency Generation – Emergency generation is the incremental cost associated with dispatching generating resources at very high output levels that exceed their typical economic operating range. Pushing units to generate at such high levels can impose additional wear and tear on units, and consequently impose incremental maintenance costs. We assume that all generating units can produce incremental output at their "emergency maximum" rating, which is assumed to exceed their "economic maximum" rating by 1% at a marginal cost of $500/MWh, as explained in Section II.E above.

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87 The realized price of purchasing imports and selling exports also depends on who owns the transmission rights needed to import and export power. Whoever owns the rights to send power across a particular transmission path will likely be able to capture the value of that transmission, buy power in the lower-price market, schedule the power to flow across that path, and sell into the higher-price market. For example, if exporters generally own the transmission rights, then they obtains the market price at the buyer's location (*i.e.*, the higher-cost market). Alternately, if importers generally own the transmission rights, then the importer can buy the power at the seller's location (*i.e.*, the lower-cost market). For the purpose of our simulations, we assume that importers and exporters each own 50% of transmission rights needed for import and export transactions. This means that imports and exports are transacted by the Study RTO utility at market price that reflects the average of the market prices at the source and delivery point. However, as we note further below, changing this assumption can have a substantial impact on total customer reliability costs and, thus, a significant effect on economic planning reserve margins.

88 This approach implies a number of assumptions, including that the net export revenues will be credited against the Study RTO cost of service and, thus, flow back to customers. This would not necessarily be the case if, for example, some export revenues were earned by independent power producers (IPPs) rather than a regulated utility.

89 For a summary of the APC metric and its limitations see SPP (2012a), Section 5.

90 In other words, adding CTs has a negligible impact on the dispatch profile of baseload units and so baseload-related production costs will remain unchanged across different reserve margin levels. However, baseload production costs are orders of magnitude greater than the reliability-related costs we report, making it difficult to report these results graphically. We do summarize total costs, including baseload-related costs, when comparing total customer costs in Section IV.D.2 below.

Emergency Hydro **–** Reliability costs associated with emergency hydro dispatch. The marginal system cost of dispatching these resources is difficult to quantify because it depends on the opportunity cost of not saving the resources for later emergencies as well as any societal costs associated with reduced reservoir levels. We assume emergency hydro has a marginal system cost and dispatch price of $3,000/MWh.[91]

Economic and Emergency DR **–** Load curtailment costs associated with two types of demand response resources: (1) Economic DR, which offers into the energy market in all hours at costs ranging from $100 to $1,000/MWh and which may be dispatched an unlimited number of times; and (2) Emergency DR, which does not offer into the energy market but can be dispatched a limited number of times during emergencies at a cost above $2,000/MWh. We assume that these dispatch costs reflect the payments made to these DR resources and assume that it also reflects the net cost that service interruptions impose on DR suppliers, as explained in Section II.C.4 above.

Operating Reserves Shortages **–** Reliability costs imposed by temporarily operating the system with depleted operating reserves during scarcity events. We do not attempt to calculate these costs explicitly because doing so is a complex exercise in evaluating the incremental contingency risks endured at each reserve level. Instead, we calculate these costs implicitly using the administrative "operating reserves demand curve" covering a $3,000-$7,000/MWh range of prices as discussed in Section II.E above. This administrative pricing curve is similar to the administrative scarcity pricing mechanisms recently implemented by several U.S. RTOs.[92] If such an operating reserves demand curve is designed efficiently, it will reflect the marginal system costs incurred when depleting operating reserves.

Voltage Reductions **–** System costs imposed by implementing a system-wide voltage reduction as the last resort before shedding load. These costs could include both equipment damage caused by the voltage reduction and lost economic value to end users (*e.g.*, due to motors running at a lower speed). We assume voltage reductions incur a system cost of $7,000/MWh, or just below the assumed VOLL as explained in Section II.E above.

Load Shedding **–** Service interruption costs imposed at a VOLL of $7,500/MWh for the average customer typically curtailed as explained in Section II.E above.

Figure 14 summarizes the annual averages of total Study RTO-wide reliability costs over a range of planning reserve margins. For each reserve margin level, we show the weighted-average reliability costs across all 9,600 annual simulations. At the lowest reserve margin shown in the chart, average annual reliability costs are high and are primarily driven by the high cost of imports during scarcity conditions. Other factors such as the value of lost load, DR interruption costs, and peaker dispatch costs impose relatively modest reliability costs even at low reserve margins. As planning reserve margins are increased, total reliability costs drop more quickly than the increases in capital and production cost associated with adding CTs. As a result, total

[91] See additional discussion in Section II.E above.

[92] For additional discussion of how administrative demand curves for operating reserves are used to set prices and reflect marginal system costs during scarcity events, see Newell, *et al.* (2012), Section V.A.2.

costs drop as the reserve margin increases until the (risk-neutral) "optimal" quantity of capacity has been added at a planning reserve margin of 10.3%. After crossing this minimum cost point, the capital costs of adding more capacity exceed the benefits from reduced reliability costs, and so total costs increase.

Note that at the 10.3% reserve margin, the Study RTO has a planning reserve margin that is substantially below the 15% reserve margin we assumed in all of the neighboring regions. This means that the neighbors are providing substantial assistance to the Study RTO, allowing it to reduce both costs and reliability events. This also means that the Study RTO is relying on its neighbors in a way that increases those regions' reliability-related costs. In other words, the Study RTO is able to minimize its costs at the 10.3% reserve margin only as long as the neighbors are indirectly "subsidizing" resource adequacy for the Study RTO. If the neighbors were to reduce their own reserve margins below 15%, then the Study RTO's cost-minimizing reserve margin would increase.[93]

Another prominent feature of the chart is that net import costs represent a large portion of total reliability-related costs and these costs drop more quickly than other costs. This is because adding capacity within the Study RTO not only allows one to displace higher-cost imports with lower-cost internal supply, but also reduces the market price at which all imports must be purchased. In other words, we incorporate price suppression as a "benefit" from this cost-of-service perspective, even though it is not a benefit from a broader societal perspective as discussed further in the following section. Further, this benefit is tied to the assumption that external regions would maintain a 15% planning reserve margin. The benefit consequently would not be sustained if the external regions' generation investment decreased.[94]

Additionally, the size of net import costs is greatly influenced by our assumption about who owns the transmission rights. We assume that customers in the Study RTO own the rights to half of all import and export capability on each of its interties, meaning that they will earn the price differential between the importing and exporting markets in all hours. However, as a general rule any importer, exporter, power marketer, or transmission owner may own some portion of these transmission rights. If we make alternative assumptions about transmission ownership, the optimal cost-of-service reserve margin changes from 10.3% in the base case, down to 8.3% with an importer-owns assumption and up to 12.3% with an exporter-owns assumption.[95]

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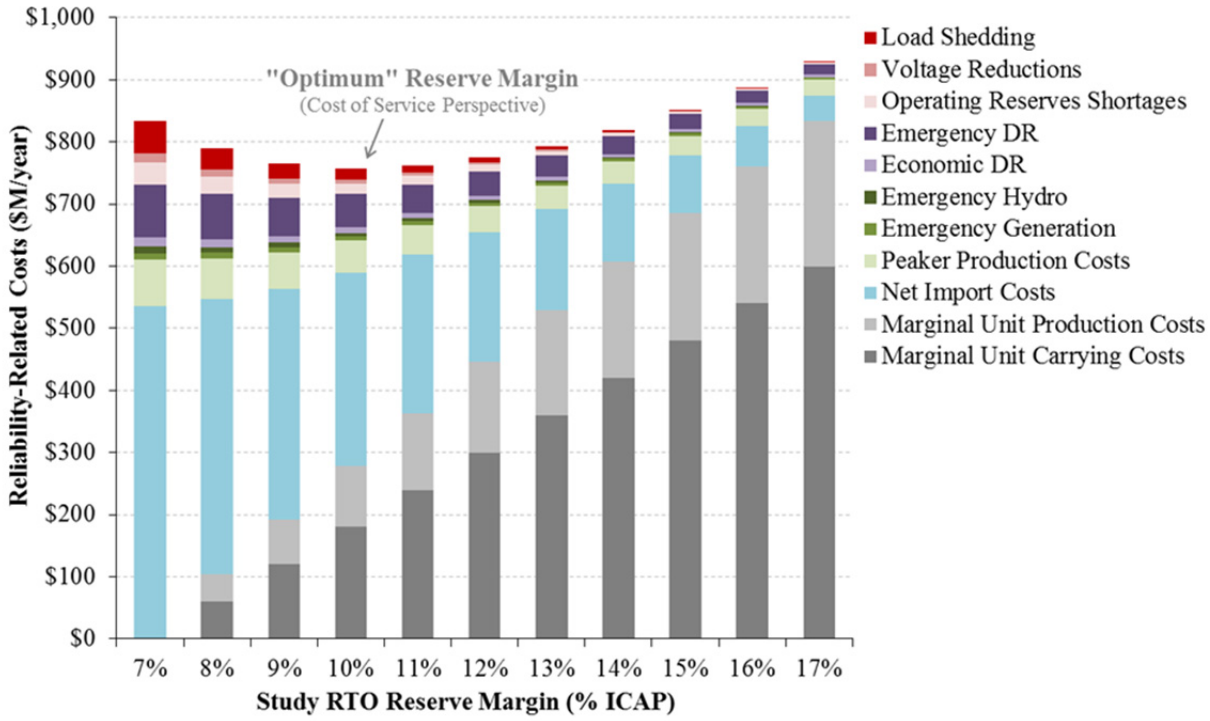
93 See additional discussion of these impacts in Sections III.A.3 and III.B.2.

94 Note that increasing the Study RTO reserve margin will reduce prices and reliability events in neighboring regions, both of which may result in the external region reducing its own reserve margin.

95 Note that as a net importer, the Study RTO achieves greater "price suppression" benefits from building capacity under the exporter-owns assumption than under the importer-owns assumption (because in the importer-owns case the price suppression "benefit" is offset by a similarly-sized offsetting price suppression "cost" imposed by the reduced value of its transmission rights). This is why the importer-owns assumption results in a lower optimal reserve margin while the exporter-owns assumption results in a higher optimal reserve margin.

The total cost curve shown in Figure 14 has a shape similar to what we have observed in many different systems in our own studies as well as in other value of service studies.[96] The curve is relatively flat near the minimum average cost point, indicating that expected total costs do not vary substantially between reserve margins of 8% to 14%. However, as we discuss further below, the lower end of that minimum cost range is associated with much more uncertainty in realized annual reliability costs and a much larger number of severe, high-cost reliability events. While the weighted average of annual costs for the Study RTO is very similar over the 8% to 14% planning reserve margin range, the higher reserve margin would avoid a majority of the high-impact, high-cost events that would be experienced at the 8% planning reserve margin. In other words, at the 14% reserve margin, a greater proportion of total annual costs are associated with added CTs (which have little uncertainty), and a smaller proportion of the average annual costs are from low-probability but high-cost reliability events.

Figure 14
Study RTO Reliability Costs as a Function of Study RTO Reserve Margin
(Risk-Neutral, Cost-of-Service Perspective)



Notes:
Study RTO reliability-related costs for Base Case simulations.
Expected annual costs are minimized from a cost-of-service perspective at a planning reserve margin of 10.3%.

[96] For example, see Keane, *et al.* (1992) pp. 824, 826; Poland (1988), p.21; Munasinghe (1988), pp. 5-7 and 12-13; and Carden, Pfeifenberger, and Wintermantel (2011).

3. Minimizing Cost from a Risk-Neutral, Societal Perspective

In this section, we estimate the risk-neutral, cost-minimizing reserve margin from an overall societal rather than a cost-of-service perspective. Under the cost-of-service perspective, we took a narrow geographic view and evaluated end-user costs for only the Study RTO without considering any reliability-related costs imposed on neighboring regions. In this section, we evaluate total reliability-related costs incurred across all four regions, regardless of whether those costs are incurred within the Study RTO or one of the neighboring regions. While any one individual utility may rationally apply the objective of minimizing customer costs from a single-system perspective, the broader societal perspective is more applicable in many contexts. For example, this broader geographic view of societal costs is more relevant for a large RTO or jurisdictional authority whose responsibility may span many utility service areas or several states.

We simulate reliability costs over the same range of reserve margins examined in the previous section, but estimate total system costs across all four study regions. The following cost components are identical from both the societal and cost-of-service perspectives as discussed above:

- Marginal Unit Carrying Costs
- Marginal Unit Production Costs
- Peaker Production Costs
- Emergency Generation Costs
- Emergency Hydro Dispatch Costs
- Economic and Emergency DR Interruption Costs
- Operating Reserves Shortage Costs
- Voltage Reduction Costs
- Load Shed Costs

However, the remaining components differ from a societal perspective. While the cost-of-service perspective assesses the costs of all imports (exports) at the purchase (or sales) price, this accounting does not apply to a multi-regional societal cost perspective. We thus removed the Net Import Cost category and added two cost categories to account for reliability costs incurred in neighboring regions. Note, however, that in this study marginal generation capital and production costs are only incurred in the Study RTO; no generation is being added in the neighboring regions. The reliability costs incurred in neighboring regions are calculated in the same way that they are calculated for the Study RTO, but are reported separately as:

Neighbors' Emergency Event Costs – Neighbors' emergency event costs include most of the cost categories evaluated, including: emergency generation, emergency hydro, economic DR, emergency DR, operating reserves shortages, voltage reductions, and load shedding. We assume that the neighboring regions have the same reliability procedures and emergency costs as the Study RTO. Note that adding additional capacity within the Study RTO will reduce the frequency of each of these types of emergency events not only internally, but also externally.

Neighbors' CT and Peaker Production Costs – Neighbors' CT and peaker production costs mirror the Peaker Production Cost category of the Study RTO.[97] Adding capacity in the Study RTO will reduce these costs in neighboring regions by allowing the Neighbor to import more during some occasions when high-cost peakers would otherwise need to be dispatched.

Figure 15 summarizes these total system reliability costs from a societal perspective over a range of reserve margins based on all 9,600 annual simulations for each reserve margin level, with reserve margins reported for both the Study RTO as well as the combined four-system region. As in the previous section, these costs represent the weighted average across all simulated scenarios. The total represents the combined total of the four-system societal costs on a risk-neutral basis. All of the colored slices are identical in size and meaning as those reported in the previous cost-of-service section, except for the two blue slices representing cost changes in the neighboring regions. In other words, we have eliminated net import costs (light blue slice) from Figure 14 above, but added the neighboring regions' reliability costs (light and medium blue slices) to Figure 15 below. In addition, we report cost results along the x-axis not only as a function of the planning reserve margin in the Study RTO, but also as a function of the reserve margin for the combined four-system region.[98]

As shown in Figure 15, from a total societal cost perspective, the optimal target reserve margin in the Study RTO (assuming the neighboring regions maintain a 15% reserve margin) is reduced from 10.3% under the cost-of-service perspective to 7.9% under a societal perspective. The primary reason for this difference is that, while customers within the Study RTO can benefit from import price reductions by increasing their own internal reserve margin, such price reductions are not a benefit from a societal-cost perspective. From a study RTO cost-of-service perspective, increasing the Study-RTO reserve margin to 10.3% is cost-effective because it reduces the net cost of imported power, both by reducing the amount of energy imported and by reducing the price paid for imported power. However, additional capacity above the 7.9% reserve margin is not beneficial from a societal-cost perspective because the Study-RTO benefit is outweighed by the combined impact on neighboring RTOs and the additional capital expenditure.[99]

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[97] With the exception that this category for the external regions also includes costs from units that happen to have the exact same price as the marginal CT. Sometimes the marginal unit will displace imports from higher-cost resources, but sometimes it will also displace imports from equally-priced CTs, which is why we include these costs as well for the neighboring regions.

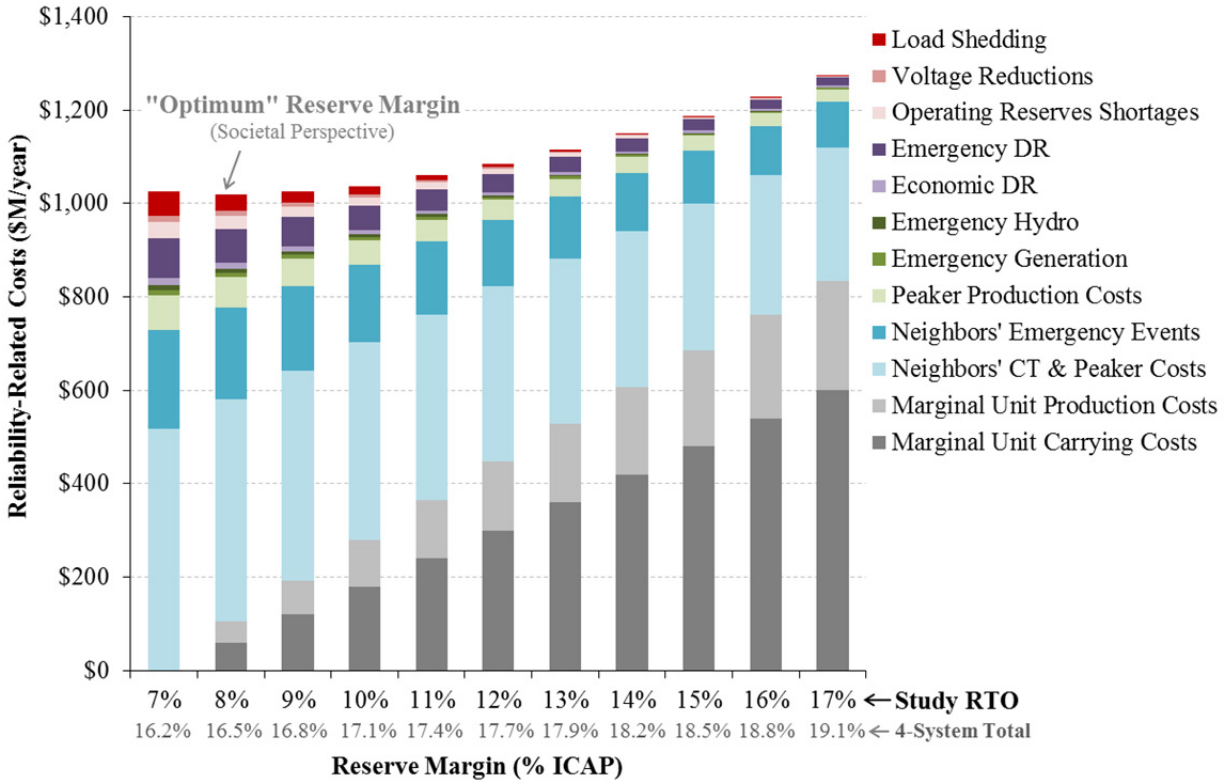
[98] Note that we add capacity only inside the Study RTO and not in any of the Outside Regions. The total reserve margin for the four systems combined changes only because capacity is being added in the Study RTO. The installed capacity in the neighboring regions is held constant at the original 15% reserve margin.

[99] In other words, "optimizing" the system from a Study RTO cost-of-service perspective aims to provide maximum benefit to customers (excluding suppliers impacts) in the Study RTO (excluding impacts on neighboring regions), which would generally introduce some deadweight loss relative to the "optimum" solution that one would achieve if planning across multiple systems from a societal perspective without regard to which supplier, customer, or region benefits most.

Figure 15 and Table 7 also show that the 7.9% Study RTO reserve margin, combined with 15% Neighbor reserve margins, is equivalent to an overall four-system reserve margin of: (a) 13.0% if measured against the non-coincident peak load, and (b) 16.5% if measured against the coincident peak load as reported in the figure. This 16.5% reserve margin is higher than the individual systems' reserve margins because the neighbors' 15% reserve margin and the Study RTO's 7.9% target reserve margin are all reported relative to their individual systems' non-coincident peak loads, the sum of which is higher than the combined four-system coincident peak load.

Because the Study RTO's optimal internal reserve margin is much lower than the neighbors' assumed 15% reserve margins, this means that the Study RTO is relying more heavily on the neighboring regions during scarcity conditions, and that the neighboring regions are "supporting" resource adequacy in the Study RTO through the combination of their 15% reserve margin and intertie capabilities.

Figure 15
Reliability Costs in all Regions as a Function of Study RTO Reserve Margin
(Risk-Neutral, Societal Perspective)



Notes:
Reliability-related costs for all four regions in the Base Case scenario.
Societal costs are minimized at reserve margins of 7.9% in the Study RTO (measured against Study RTO non-coincident peak load) or 16.5% across all four regions (measured against four-system coincident peak).

Table 7
Coincident and Non-Coincident Reserve Margin Accounting
At the Societally Optimal Reserve Margin

	Generation	Peak Load		Reserve Margin	
		Non-Coincident	Coincident	Non-Coincident	Coincident
	(MW)	*(MW)*	*(MW)*	*(%)*	*(%)*
Study RTO	53,950	50,000	48,605	7.9%	n/a
Neighbor 1	69,000	60,000	58,686	15%	n/a
Neighbor 2	46,000	40,000	38,604	15%	n/a
Neighbor 3	34,500	30,000	28,773	15%	n/a
Total	**203,450**	**180,000**	**174,668**	**13.0%**	**16.5%**

A planning effort designed to optimize the location and size of resource additions across all four interconnected regions would likely result in decreasing the neighbors' reserve margins while increasing the Study RTO reserve margin. However, the target reserve margins for the four regions that result in the lowest cost for the entire system will depend on a wide variety of factors. For example, some of the factors determining the cost effectiveness of increasing the reserve margin in a particular region would include: (a) whether a region is an import-constrained area like the Los Angeles Basin, New York City, or Eastern PJM; (b) whether the sub-region is highly dependent on limited-dispatch DR during peak periods, which would make adding CTs more valuable; (c) whether two sub-regions are well-interconnected with large load diversity, allowing both sub-regions to gain substantial resource adequacy benefits from the same capacity resource; and (d) whether adding new CTs in one region would allow for the retirement of aging resources with high fixed costs.

4. Risk Mitigation Benefit of Increasing Reserve Margins

The economic results shown in the previous sections assume risk neutrality with respect to the uncertainty and volatility of reliability-related costs. This allows us to compare total costs at different reserve margins in Figure 14 and Figure 15 simply as the probability-weighted average of annual reliability costs for all 9,600 simulated scenarios. However, there is substantial volatility around the average level of possible reliability cost outcomes. Most simulated years will have only very modest reliability costs, while a small number of years have very high reliability costs. These high-cost outcomes account for the majority of the weighted average annual costs shown as the individual bars in Figure 14 and Figure 15.

Figure 16 summarizes this risk exposure by comparing the weighted average costs for different reserve margins (shown as the individual bars in Figure 14, from a cost-of-service perspective) to annual costs under the most costly possible outcomes, represented by the 85^{th}, 90^{th}, and 95^{th} percentile of annual reliability costs across all 9,600 simulated scenarios. The figure shows that the majority of all reliability-related costs are concentrated in the most expensive 15% of all simulation runs for each planning reserve margin. In other words, for 15% of possible annual outcomes, the annual reliability costs are at or above the 85^{th} percentile line shown in the chart. This means that, while total average costs change by a relatively modest amount over a range of planning reserve margins, differences in planning reserve margins have a much larger impact on

the uncertainty in reliability costs and the likelihood of high-cost outcomes than can be encountered in any particular year.

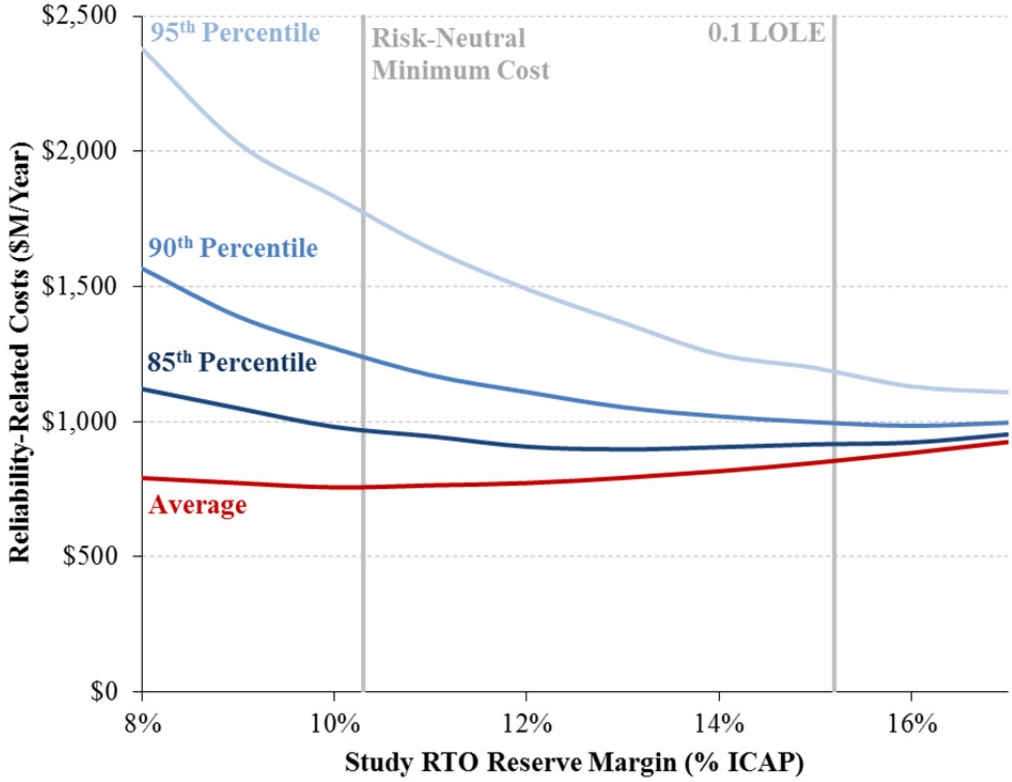
Considering the much higher cost uncertainty exposure at lower reserve margins, many planners and policy makers may wish to set planning reserve margins above the risk-neutral economic optimum. In our sample system, even a several percentage point increase in the target reserve margin would only slightly increase the average annual costs, but substantially reduce the likelihood of experiencing very high-cost events. However, without evaluating the magnitude of the increase in average costs and decrease in extreme event costs, policy makers would not be in a position to determine whether a higher reserve margin is justified by its risk mitigation benefits.

For example, our simulations show that the risk-neutral optimal planning reserve margin is 10.3% for the Study RTO from a cost-of-service perspective. In comparison, the planning reserve margin would need to be 15.2% to achieve the 0.1 LOLE standard. As Figure 14 and Figure 16 show, the increase in average annual costs required to achieve the 15.2% planning reserve margin is relatively modest at approximately $90 million per year. However Figure 16 also shows that this would reduce the annual costs incurred once in a decade (*i.e.*, costs above the 90th percentile) by at least $270 million per year, and the costs incurred once in 20 years (*i.e.*, costs above the 95th percentile) by at least $630 million per year. In other words: (a) a risk-neutral policy maker would not increase reserve margins above the 10.3% risk-neutral optimum because, by definition, the expected costs would exceed expected benefits; (b) a somewhat risk-averse policy maker might increase reserve margins slightly but possibly not enough to meet 0.1 LOLE at 15.2% reserve margin where the costs exceed the benefits by a ratio of approximately three-to-one; and (c) a highly risk-averse policy maker might wish to meet or even exceed the 15.2% reserve margin needed to meet 0.1 LOLE.

In evaluating these cost and risk tradeoffs, policy makers should also consider that suppliers and customers will be able to hedge a significant portion of these risks through forward contracting. As we discuss further in Section IV, a large portion of the risk of encountering the high-cost outcomes illustrated in Figure 16 is related to weather uncertainty. Some of that risk exposure can likely be hedged cost effectively, including through seasonal forward contracts. For example, many suppliers and load serving entities (LSEs) in ERCOT hedge most of their summer price spike exposure through forward contracts on a seasonal basis.[100]

[100] See additional discussion and documentation in Section IV.A.3 below.

Figure 16
Uncertainty Distribution of Annual Reliability-Related Costs
(Cost-of-Service Perspective)



Notes:
Study RTO reliability-related costs for Base Case from a cost-of-service perspective.

5. Sensitivity to Forecast Error and Forward Planning Period

As explained in Section II.D.2 above, uncertainty in economic growth and the consequential economic load forecasting uncertainty are key planning considerations. Uncertainty caused by economic forecasting error increases with the forward period. This is unlike annual weather-related uncertainty, which is generally assumed to be constant over time. Adopting a longer forward planning period therefore will result in higher load forecast uncertainty and, if resource additions cannot be modified on a shorter-term basis, a higher likelihood of reliability and scarcity events. This means that increasing the forward period in resource adequacy studies will also increase the reserve margin necessary to achieve any given reliability standard.

In our Base Case analysis, we adopt a four-year forward planning period based on a conservative estimate of the approximate lead time needed to develop new resources.[101] The lead time for

[101] Note that although the entire development timeline for most new plants is greater than four years, much of that development work, including siting and permitting, can be done without making major irreversible financial commitments. This means that the time needed for actual plant construction is most relevant when the resource investment decision is truly locked in. Developing and constructing a natural gas CC or CT takes approximately 3.25 and 2.8 years respectively, see Spees, *et al.* (2011), Appendices A.3 and B.3.

developing new resources is also the reason that PJM and ISO-NE's capacity markets rely on a three-year forward period. In non-RTO markets and the integrated planning processes subject to state regulation, at least a portion of all planning decisions are often made on a schedule that looks more than three years forward.[102] Note, however, that most systems also have substantial flexibility to adjust their total resource portfolio on a shorter-term basis, including even on a one-year forward basis. For example, there is substantial capability to adjust DR commitments, revise import-export balance, adjust retirement or retrofit decisions, delay or accelerate plant development efforts, and invest in plant upgrades on a shorter-term basis.

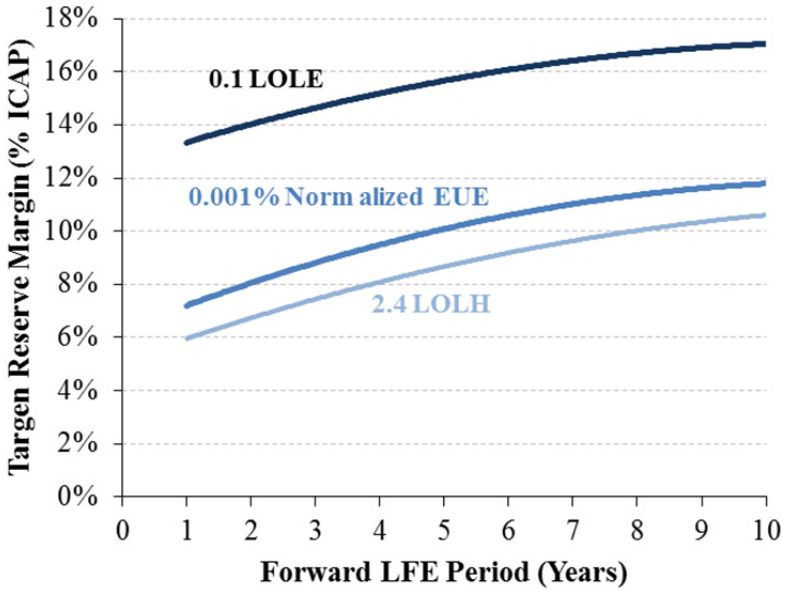
We examine the implications of revising the forward planning period on the reserve margin standard and total system costs by adopting alternative economic forecast error assumptions consistent with different forward periods as documented in Section II.D.2 above. Increasing the forward period increases the economic load forecast error, which consequently increases the planning reserve margin whether the reserve margin is reliability-based as shown in Figure 17, or economically-based as shown in Figure 18.

As Figure 17 shows, reducing the forward planning period from four years to one year would reduce the 0.1 LOLE-based planning reserve margin by 1.7%, from 15.2% to 13.5%. This would, of course, require that sufficient short-term resources exist that could be mobilized on a 12-month basis should economic growth prove greater than anticipated.[103] As noted, such short-term resources might include DR resources (assuming the market is not fully saturated), upgrades to existing plants (or new plants under construction), reactivations of mothballed plants, an increase in net import commitments, or accelerating in-service dates of new plants under development.

[102] For example, see the discussion of the Long-Term Resource Planning processes implemented by California's investor owned utilities under the oversight of the state commission in Pfeifenberger, *et al.* (2012).

[103] For example, assume that most resource investment decisions (*e.g.*, for existing generation) were made on a longer term basis but the final 5% of resources were not procured until one year prior to delivery. However, the actual amount of incremental resources needed on a one-year forward basis may only be 3% or as high as 7% if economic growth were higher or lower than expected in prior planning exercises.

Figure 17
Reliability-Based Resource Adequacy Standard vs. Forward Planning Period

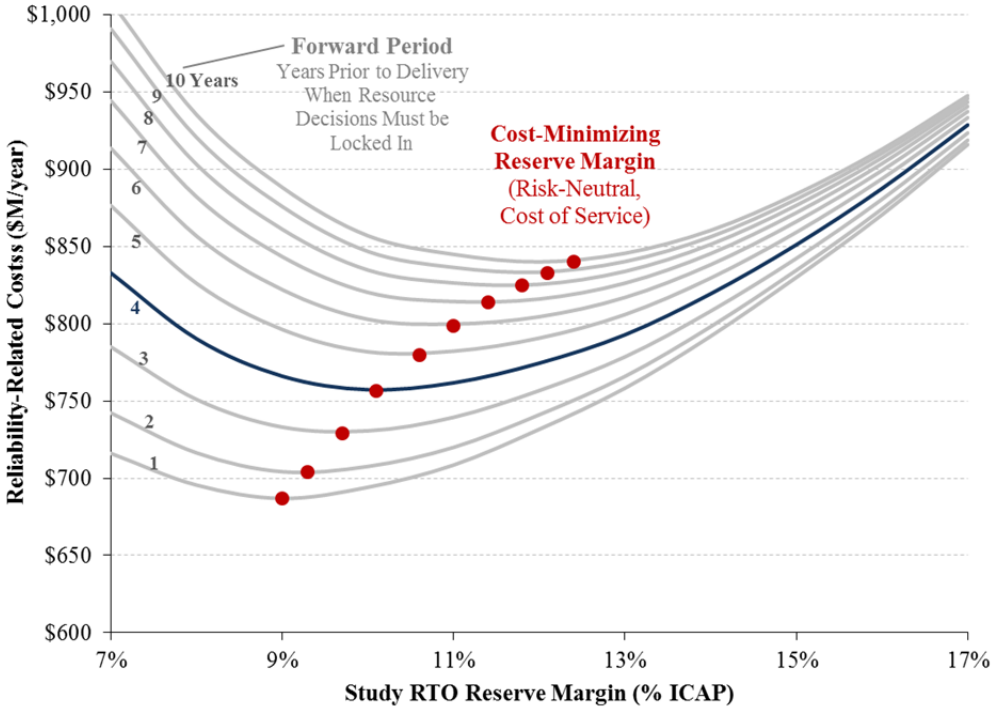


Notes:
Study RTO reliability-based reserve margin vs. forward period.
Load forecast error varies with planning period, see Section II.D.2.

Figure 18 similarly shows that increasing the forward period will increase the economically optimal planning reserve margin. The chart shows total reliability-related costs from a risk-neutral cost-of-service perspective (as in Section III.A.2 above) under different forward periods. The Base Case assumption of a four-year forward period is shown as a blue line while the gray lines show costs ranging from a one-year to a ten-year forward planning period. Total costs increase substantially with a higher forward period because there is a much greater risk of high-impact events associated with under-forecasting economic load growth (and greater capital costs required to build sufficient capacity to avoid such events). However, if sufficient short-term resources exist to allow for a reduction of the forward planning period from four years to one year, then the risk-neutral optimal reserve margin would decrease by 1.3%, from 10.3% to 9.0%.

This suggests that if a region has a reasonably high amount of additional short lead-time DR resources, it may be beneficial to adopt a forward procurement approach similar to that used in PJM, where most resources are procured three years forward but the remaining 2.5% of resources are procured on 2-year, 1-year, and short-term basis. This could reduce total procurement costs by reducing the procured reserve margin more often than not. However, it also increases the risk of under-procurement in a high load growth situation. If substantially more than 2.5% of resources are needed on a short-term basis, there may not be enough supply available to meet the need; or the only available resources may be high-cost DR that is not cost-competitive under ordinary circumstances. We further examine the implications of high DR penetration in Sections III.C and IV.C below.

Figure 18
"Optimal" Reserve Margin as a Function of Forward-Planning Period
(Risk-neutral, Cost-of-Service Perspective)



Notes:
Study RTO reliability-related costs for Base Case from a cost-of-service perspective.
Load forecast error varies with planning period as described in Section II.D.2.

B. Impact of System Characteristics

This section of our report summarizes the extent to which target reserve margins are affected by system characteristics. The specific sensitivities we explore are: (1) system size (40% Size Case and 40% Size and Transmission Case); (2) intertie size and neighbor assistance (Long Neighbors Case, 50% Transmission Case, and Island Case); (3) using CCs rather than CTs as the marginal capacity resource (Marginal CC Case); and (4) higher penetration levels of intermittent renewable resources (High Wind Penetration Case).

1. Impact of System Size

We first examine the implications of system size under two alternative cases, in which: (1) we reduce the RTO Study Region to 40% of its Base Case size (from a peak load of 50,000 MW to 20,000 MW); and (2) we reduce the system to 40% of its Base Case size and also reduce all interconnections with neighboring regions to 40% of their Base Case size. In both of these cases we maintain the same resource mix, unit sizes, and external region characteristics as in the Base Case.

Table 8 summarizes the target reserve margin results for these two change cases compared to the Base Case. The 40% Size Case shows that both the 1-in-10-based and the economic target reserve margins decrease for the Study RTO. The 0.1 LOLE target drops only slightly from

15.2% in the Base Case to 14.8% in the 40% Size Case, while the other reliability-based targets drop more substantially from 8.2% to less than 6% under the 2.4 LOLH standard and from 9.6% to 7.5% under the 0.001% Normalized EUE standard. The risk-neutral, cost-minimizing reserve margin decreases even further, from 10.3% (cost-of-service perspective) and 7.9% (societal perspective) to less than 6% under both perspectives. The reason for the lower planning reserve margin targets is that the smaller Study RTO is able to rely more heavily on neighbor assistance. This is the case because the smaller RTO requires a fewer imports during reliability events. In other words, the neighbors are able to provide proportionally greater assistance to the smaller Study RTO.

If we also proportionally reduce the size of the interconnections with neighboring regions, then some of these neighbor-assistance benefits are lost to the smaller Study RTO as also shown in Table 8. The target reserve margin based on 0.1 LOLE is reduced from 15.2% to only 15.1% (compared to 14.8% when maintaining the Base Case size of the interconnections) while the 0.001% Normalized EUE and 2.4 LOLH standards only increase to 8.1% and 6.9% respectively. The economic target reserve margins still remain at less 6% (outside our study range). The combination of these alternative simulation cases shows that: (a) a small system can rely more readily on neighbor assistance to reduce its planning reserve margin; and (b) the value of neighbor assistance is substantially greater for a well-interconnected small system.

Table 8
Study RTO Reserve Margin Targets with a Smaller System Size

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case (50,000 MW)	15.2%	8.2%	9.6%	10.3%	7.9%
40% RTO Size (20,000 MW)	14.8%	<6%	7.5%	<6%	<6%
40% Size w/ 40% Intertie	15.1%	6.9%	8.1%	<6%	<6%

These lower target reserve margins for the smaller system may initially appear counter-intuitive or inconsistent with general industry experience. Historically, many small utilities maintained reserve margins in excess of 20% and were able to reduce these margins over time by merging, interconnecting with neighbors, developing reserve-sharing agreements, or joining larger RTO systems. This apparent disconnect with our results is primarily driven by the fact that traditional utilities were much smaller and more "islanded" than even the "small" Study RTO (20,000 MW) in our simulations. Traditionally, many utilities may have relied less on interties for reliability because many: (a) were not as well-interconnected with their neighbors; (b) would have faced more difficulty in obtaining neighbor assistance during peak events, particularly prior to the implementation of reserve sharing agreements and liquid wholesale power markets; and (c) may have been conservative in assessing the reliability value of their interties in the absence of firm power purchase commitments.

In addition, the high reserve margin targets of many small utilities are driven by a single-largest-contingency analysis. For example, a small utility's reliability standard may stipulate that the utility is able to meet peak load even if the single largest generator or transmission line were to

fail. In a large system, such a contingency criterion typically does not affect the planning reserve margin. However, for a small utility serving only a few thousand MW of load, contingency considerations can substantially increase planning reserve requirements. We did not conduct any contingency analysis in this study, but even in the "small" 20,000 MW Study RTO Case, such contingencies are unlikely to affect planning reserve margins. Nevertheless, if we had treated the small system as a substantially more islanded region, then it would better reflect the historical experience of smaller utilities and would result a higher reserve margin requirement.

2. Intertie Size and Neighbor Assistance

Strong interties with neighboring regions provide both economic and physical reliability value during peaking conditions. Load and generation diversity mean that the most extreme scarcity conditions are unlikely to occur at the same time in neighboring markets. This inter-regional diversity means that the Study RTO will often be able to rely on emergency imports to avoid load shedding and improve system reliability. Interties create economic benefits as well, for example, by allowing the Study RTO to purchase imports from external CTs rather than dispatching higher-cost internal DR resources.

We examine the value of interties and neighbor assistance for a number of cases, with the planning reserve margin results summarized in Table 9. The results are shown in order of increasing availability of neighbor assistance, including: (1) a "Long Neighbors Case" where the neighbors' reserve margins are increased to 20% compared to 15% in the Base Case (and intertie capability equal to the Base Case); (2) the Base Case, where the neighbors have 15% reserve margins and the Study RTO has 11,000 MW of intertie capacity); (3) a "50% Transmission Case," with interties at 50% relative to the Base Case (and neighbors' reserve margins at 15%); and (4) an "Island Case" with no interties.

The table shows that the interties offer substantial benefits from both a physical reliability and economic perspective. Maintaining the 0.1 LOLE requires increasing the internal reserve margin from 13.0%% in the Long Neighbors Case, to 15.2% in the Base Case, 15.8% in the 50% Transmission Case, and 18.5% in the Island Case. In terms of the economic benefits of neighbor assistance and interties, these cases show that the cost-minimizing reserve margin (from a risk-neutral cost-of-service perspective) increases from 8% in the Long Neighbors Case, to 10.3% in the Base Case, 12.3% in the 50% Transmission Case, and 16% in the Island Case.

Table 9
Study RTO Reserve Margin Targets with Varying Availability of Neighbor Assistance

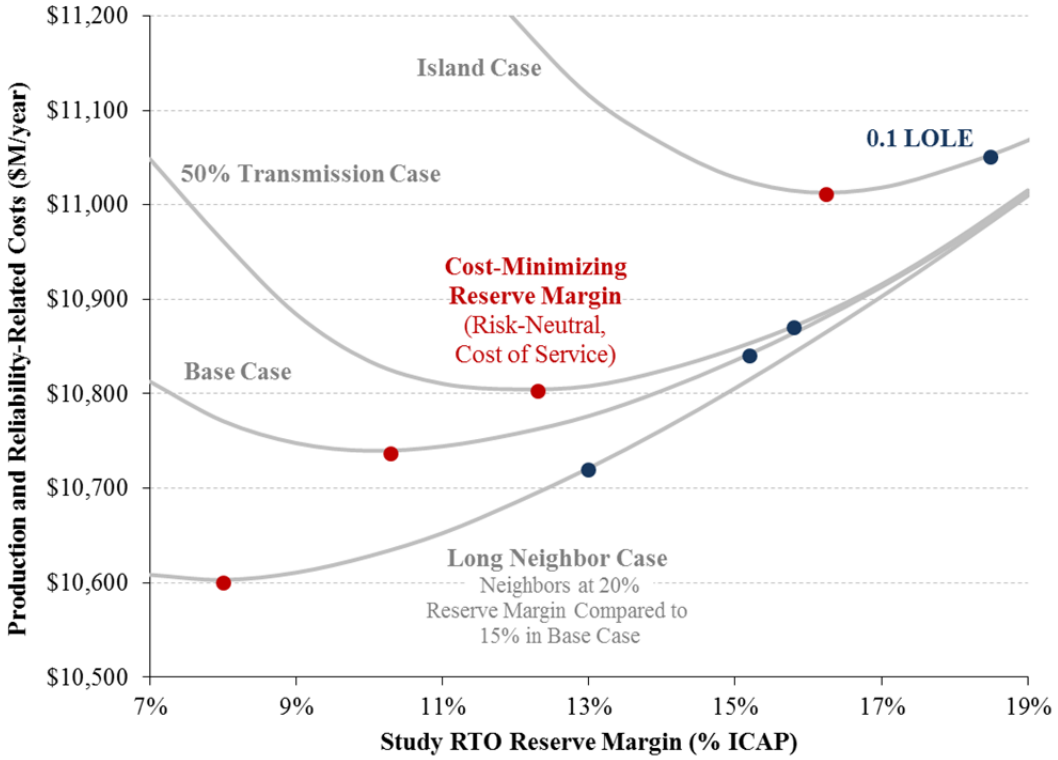
Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%

That interties provide substantial economic value is also shown in Figure 19, which displays total system production and reliability-related costs from a risk-neutral, cost-of-service perspective for different planning reserve margins and interconnection assumption. Not counting the costs of the interconnections themselves, the figure shows that system costs increase as interconnections decrease for a given level of reserve margin. For example, at a 14% planning reserve margin for the Study RTO, reducing interties by 50% increases average annual costs by $21 million per year relative to the Base Case. Totally eliminating the interties increases average annual costs by $262 million per year relative to the Base Case. However, as shown in Figure 19, these economic costs can also be reduced substantially by increasing the planning reserve margin. Reducing interties at a particular reserve margin increases system costs because it reduces the ability of the Study RTO to import lower-cost resources. This generally reduces costs at any time when the system is importing, which is particularly valuable during scarcity and emergency events. The Long Neighbor Case also illustrates that assumptions about reserve margins maintained in external systems has a substantial impact on the Study RTO's target reserve margin.

Maintaining a 0.1 LOLE also imposes greater costs in more isolated systems, because the Study Region not only loses the opportunity of lower-cost imports, but it also incurs the large capital costs associated with having to maintain a higher reserve margin. Maintaining a 0.1 LOLE in the 50% Transmission Case incurs an additional $43 million of average annual costs compared to the Base Case, while the Islanded system incurs $219 million in additional average annual costs. As the differences in reserve margin and total costs for the economic and LOLE-based reserve margin targets shown in Figure 19 demonstrate, the cost savings from increased interconnections and neighbor assistance are more substantial if the reserve margin is determined economically rather than with LOLE targets. A full study of the economic value of a particular intertie upgrade would also consider the cost of the expanded interties relative to these economic benefits, in addition to other reliability and operational benefits that the intertie might provide.

Figure 19 also shows that the value of interties increases when neighboring regions have excess capacity, because the Study RTO can rely more heavily on the neighboring regions for low-cost imports under normal as well as scarcity conditions. For example, increasing external reserve margins from 15% to 20% allows the Study RTO to decrease its internal reserve margin from 15.2% to 13.0% while maintaining 0.1 LOLE. However, it is important to note that adding external capacity is not as valuable as adding internal capacity, from either a cost or reliability perspective. In fact, increasing external capacity by 6,500 MW across the three external regions reduces the Study RTO's internal reliability requirement by only 1,100 MW. This is because external resources can only be imported if: (1) interties are sufficiently sized; (2) the interties are not derated; and (3) external regions are not simultaneously experiencing scarcity or emergency peak load conditions. The capacity value of external resources would increase if they were committed to the Study RTO on a firm basis (with firm import rights), which would mean that the Study RTO would have first rights to call them.

Figure 19
Total System Costs vs. Reserve Margin with Varying Intertie Assumptions



Note:

The vertical scale is much greater than in Figure 14 and Figure 18 above, which plot the same cost data in a different way. The magnitude of the change in system costs in the Base Case is identical for all charts, but this figure adds a baseline of total Study RTO production costs to allow the comparison of total system costs across the different cases.

The reduction in Study RTO reserve margins enabled by the interties relative to the Island case, is sometimes referred to as the "tie benefit" or "capacity benefit of interties."[104] The magnitude of these intertie benefits is estimated probabilistically as the likely quantity of energy that will be available for non-firm import from neighbors during scarcity or emergency conditions. Such non-firm imports that contribute to intertie benefits are different from, and in addition to, firm imports that are committed to the Study RTO.

The most obvious approach for modeling resources in neighboring regions might be to include all projected capacity resources, including surplus capacity. The surplus capacity would increase the estimated tie benefits and reduce the Study RTO's target reserve margin. The problem with this approach is that it will not represent a long-term stable resource adequacy target because Study RTO target reserve margins would fluctuate with changes in the external regions' reserve margins (*e.g.*, as a result of plant retirements that reduce surplus capacity). Further, the study RTO may have insufficient information to accurately project the likely quantity of resources available in the external system. Because of these challenges, ISO-NE recently abandoned this approach, opting instead to model external markets "at criterion," regardless of any actual

[104] For example, see PJM (2011).

excess.[105] This more conservative "at criterion" assumption is standard among most RTOs, primarily because the Study RTO can be fairly certain that external regions will meet their own planning reserve margin targets but cannot be totally certain that an external system's existing surplus would be maintained. The "at criterion" approach also results in a more stable internal reserve margin target. While the Study RTO may still benefit from the external regions' surplus capacity through lower-cost imports and improved reliability, changing amounts of surplus would not affect the Study RTO's planning reserve margin.

A final, more complex question relates to how much of an RTO's intertie capability should be left uncommitted or even set aside as the capacity benefit margin.[106] This is one of the key questions currently being addressed at the MISO-PJM seam in the FERC cross-border capacity deliverability proceeding.[107] Under the Point-to-Point transmission rights model used across most of North America, intertie capability is broken into two components: (1) transmission capability available to support long-term firm transmission rights that are needed for a generator to sell firm capacity across market interties (*e.g.*, from MISO to PJM); and (2) transmission set aside as CBM and awarded only on a short-term basis for non-firm energy sales. Only the uncommitted portion of the interties, including any portion that is specifically set aside as CBM, would contribute to probabilistically estimated tie benefits.[108] Firm import commitments are generally treated similarly to internal resources for determining target reserve margins.[109]

There are also a number of factors to consider in determining what portion of intertie capability to set aside for CBM. As explained by MISO and its market monitor, reducing CBM would increase the transmission that could be awarded for firm exports.[110] This would likely reduce PJM's capacity costs by allowing more MISO resources to sell capacity into PJM. On the other hand, as PJM explains, reducing CBM would reduce the realized intertie benefits and thereby increase PJM's planning reserve margin. Ultimately, determining the optimal quantity of uncommitted transmission (*e.g.*, by setting it aside as CBM) is an economic question that requires balancing the tradeoff between these factors.

3. Combined Cycle Plants as the Marginal Technology

Another study assumption is the type of marginal resource that is added in our simulations to increase the Study RTO planning reserve margin. In the Base Case, we add CTs as the marginal resource. While this is consistent with the use of CTs as the standard peaking resource, a mix of peaking, intermediate, and baseload resources is typically added under real-world conditions and in regulated resource planning efforts. The most economic type of resource to build depends on the composition of the existing fleet, the forecast load profile, projected fuel prices, and other

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105 For a more comprehensive discussion of tie benefits questions within ISO-NE, see FERC (2012), p. 2.

106 For a detailed description of NERC standards relating to CBM, see NERC (2008).

107 Under FERC Docket AD12-16-000.

108 For example, see PJM's calculation of the capacity benefit of ties based on the CBM portion of its interties, PJM (2011).

109 Note that in our modeling we effectively treat all intertie capability as CBM.

110 See MISO (2012b).

factors.[111] We test the sensitivity of our results to the assumed marginal technology under a case in which we add CCs rather than CTs to increase reserve margins.[112]

As shown in Table 10, the physical reliability implications of adding CCs and CTs are essentially identical because these technologies have similar outage characteristics. Using CCs as the marginal resource results in 15.2% and 15.3% reserve margin targets under the 0.1 LOLE standard. The small differences in CT and CC outage characteristics are not large enough to make a substantial impact on physical reliability metrics. This would generally be the expected result from adding different types of thermal generation resources that have similar outage characteristics.[113]

Table 10
Reserve Margin Targets with CC and CTs as the Marginal Resource

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case (Marginal CT)	15.2%	8.2%	9.6%	10.3%	7.9%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

Coincidentally, the economic target reserve margins between the CC and CT cases are also quite similar, but slightly lower in the CC case. This result will not hold true under all circumstances since the economic consequences of adding different types of technologies may be vary considerably. The fact that it is true in our simulations consequently cannot be generalized.

Importantly, comparing the economic reserve margin targets does *not* help to determine whether it would be more beneficial to add CCs or CTs. Comparing the net system benefits achieved by adding two different types of resources requires comparing the total system costs under each case. This is illustrated in Figure 20 below. This figure shows total production and reliability

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[111] See a more comprehensive discussion of optimal resource mix conflicts in Pfeifenberger, *et al.* (2009), Section III.A.

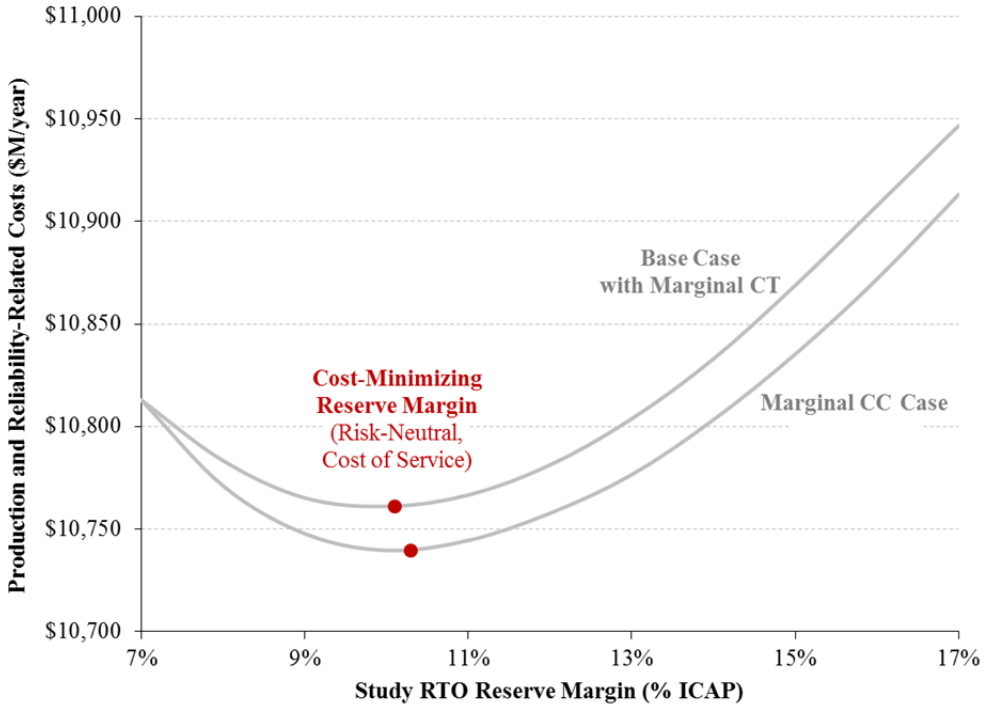
[112] More generally, a thorough system planning effort could evaluate many types of resources to determine which is the most economic. Alternately, in a deregulated market-based environment, merchant suppliers would determine which type of resource to build by forecasting the profitability of each type of potential investment. Under certain, idealized conditions the system planning and market-based approaches would both result in the same type of resource being added as discussed further in Section IV.A.1.

[113] We assume that CCs have a very slightly higher forced outage rate causing the reliability-based reserve margin targets to increase by a small amount of approximately 0.1% in the Marginal CC case. Conducting a modeling exercise at a higher level of granularity would be required to evaluate additional nuances regarding the reliability impacts of different types of thermal generation resources. For example, even though resources may have the same overall forced outage rates, there may be systems in which it would be relevant to examine the reliability implications of: (a) a large number of natural gas plants that are interconnected to the same pipeline that could expose the region to shortages caused by pipeline outages or other fuel supply constraints; (b) resources that do or do not have backup diesel fuel capability that would protect against many fuel-related outages; and (c) systems with high wind penetration or other contingency risks where fast-response CTs would provide additional reliability and operational value.

costs in the Study RTO from a risk-neutral, cost-of-service perspective for both CCs and CTs as the marginal resource. The figure shows that all-in fixed and variable costs drop faster when adding CCs than when adding CTs if starting with the same resource mix at the 7% reserve margin. This is because the greater production cost savings associated with adding CCs outweighs that technology's greater capital costs. In other words, even though the economic reserve margin targets are similar, it is more beneficial to add CCs than CTs because it will achieve greater system costs savings. The vertical difference between the red dots in the chart shows that the lowest average annual cost for CCs is $21 million per year below that of CTs.

However, this incremental cost advantage of CCs declines as more CCs are added, which is why the two cost curves are more parallel at higher reserve margins. At some point, the capital and operating cost tradeoff between the two technologies will equalize, at which point it will be optimal to add a mix of the two resource types.[114]

Figure 20
Study RTO Total Production and Reliability-Related Costs with Marginal CC or CT
(Risk-Neutral, Cost of Service Perspective)



Note:

The vertical scale is much greater than in Figure 14 and Figure 18 above, which plot the same cost data in a different way. The magnitude of the change in system costs in the Base Case is identical for all charts, but this figure adds a baseline of total Study RTO production costs to allow the comparison of total system costs across the different cases.

[114] We have not attempted to identify the optimal quantity of additional CCs before the two types of resources become equally valuable. Identifying this tradeoff point would require a slightly different analysis in which we would: (1) test the incremental cost savings after adding one CC vs. one CT; and then (2) if the CC provides more value, we would keep that asset in the mix and then test the value of adding one more CC vs. one more CT.

4. Intermittent Renewable Resource Penetration

Intermittent renewable resources such as wind and solar have a resource adequacy value significantly below their nameplate capacity because they typically cannot generate at their full capacity during peak load conditions. Because high load conditions also often correspond with low wind speeds, wind turbines' resource adequacy value generally is even below the resource's average annual capacity factor. On the other hand, a solar resource's capacity value is usually higher than its average annual capacity factor because solar output typically is more correlated with peak-load conditions. Recognizing these factors, most RTOs assign intermittent resources a capacity value based on average output during peak load hours.[115] When we calculate planning reserve margins throughout this study, we assign a nominal 15% capacity value to wind generators and 25% to solar resources.

The actual resource adequacy value of intermittent resources will depend on a number of factors and increase with: (1) the degree of correlation between load and the intermittent resource's output profile; and (2) the study region's penetration of dispatch-limited resources and storage because renewable generation during near-peak conditions will allow storage and dispatch-limited resources to generate more during peak conditions.

A more precise estimate of the intermittent resources' resource adequacy value can be calculated based on Effective Load Carrying Capability (ELCC) as currently implemented in MISO.[116] Broadly, the objective of using ELCC is to assign a capacity value to each resource type that makes them interchangeable from a resource adequacy and planning reserve margin perspective.[117] While there are various approaches to calculating ELCC, our approach is to: (a) add a small quantity of gas CTs and determine the resulting reduction in LOLE; and (b) remove the gas CTs to restore the system to its starting configuration, then add intermittent wind resources until the system LOLE is reduced by the same amount as was achieved by adding the CT. Note that this LOLE-based approach is most appropriate for a system with an LOLE-based resource adequacy

---

[115] For example, PJM assigns intermittent resources a capacity value equal to the capacity factor during summer peak periods over the previous three years, or a generic value of 13% or 38% for new wind and solar resources respectively. See PJM (2010). For a wider survey of RTO practices for assigning wind resources' capacity value, see Milligan and Porter (2005).

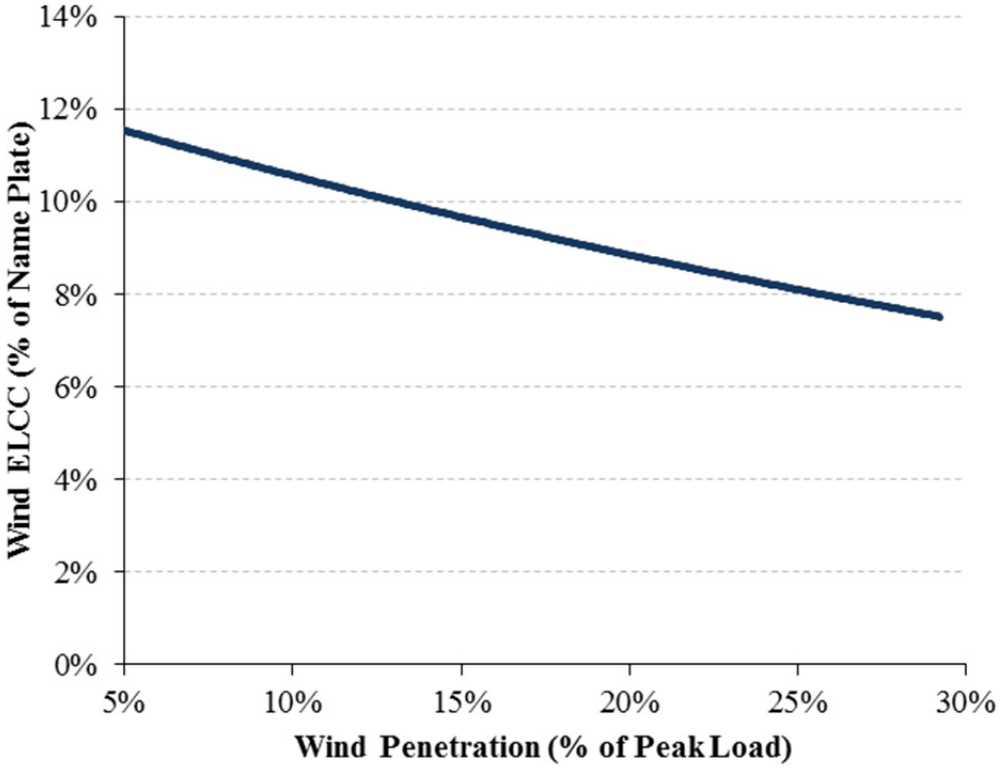
[116] MISO conducts an ELCC study each year to determine the capacity value that will be assigned to all wind resources, currently set to 13.3% of nameplate, see MISO (2012a). For additional discussion of approaches to calculating ELCC, see Milligan (1997); Wiser and Bolinger (2005); Kahn (2004).

[117] To date, ELCC calculations only consider the interchangeability from a physical reliability perspective in terms of reducing LOLE, LOLH, or EUE. It does not, and we do not here, attempt to ensure interchangeability from an economic perspective, which is inherently difficult because much of the economic value of a zero-marginal cost resource (like wind generation) is its energy value during off-peak conditions that do not materially relate to resource adequacy. Developing an economic comparison between wind and thermal resources would require one to either: (a) arbitrarily determine which component of energy value would be compared (*i.e.*, above some peaking cost threshold) to calculate ELCC; or else, (b) would simply compare the total economic value from energy and resource adequacy contributions, which is most relevant comparison for IRP purposes, but is not conceptually similar to ELCC.

standard. Slightly different approaches would be needed in systems with LOLH or EUE-based standards or those that account for resources in UCAP rather than ICAP terms.

We use this approach to calculate the ELCC of wind generation at varying wind penetration levels as shown in Figure 21 for the Study RTO. The figure shows that ELCC drops as wind penetration increases because the system is then more vulnerable to correlated low-wind conditions during peak load events. The figure shows that wind ELCC is only 12% at the 5% penetration level and drops all the way to 8% at the 30% penetration level. This indicates that the 15% capacity value that we assign to wind is high relative to its reliability contribution.[118] Note, however, that our relatively low ELCC results are driven by relatively poor wind profiles that correspond to the weather and load profiles of the study region. The average annual capacity factor for wind generators in the Study RTO is approximately 31%, but the output during peak load conditions is much lower.

Figure 21
Wind Generator's Effective Load Carrying Capability vs. Penetration



Notes:
Wind ELCC calculated as for the Base Case simulation, with 0.1% solar penetration.
Wind penetration expressed as wind nameplate capacity as percent of summer peak load.
Study RTO reserve margin is 12% at 5% wind penetration and increases as wind increases.

[118] Note that the Base Case and all the other simulation cases incorporate 3.9% renewable penetration, expressed as a percent of peak load (3.8% wind, 0.1% solar).

C. DISPLACING GENERATION WITH DEMAND RESPONSE

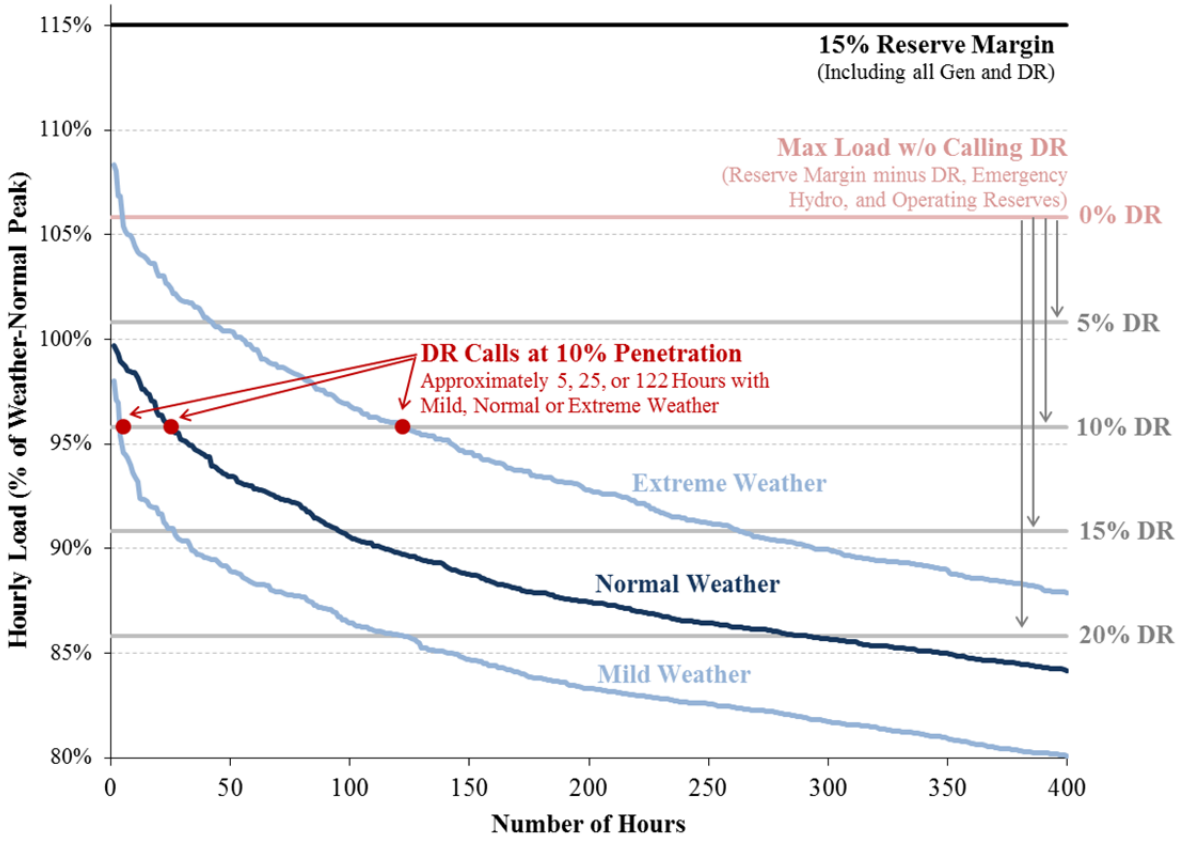
As explained in Section II.C.4 above, an important set of questions for resource adequacy in the coming years relates to the reliability and economic implications of increasing quantities of demand response. Evaluating the implications of increased DR penetration requires an approach that differs from that of using CTs or CCs as a marginal resource. When evaluating high demand response penetration, the most important questions are less related to the implications of choosing a different reserve margin but, rather, related to the implications of relying more heavily on DR as a substitute for traditional generation at a given planning reserve margin.

For this reason, we evaluate the consequences of higher demand response penetration at a fixed 15% planning reserve margin, but substitute CTs with DR resources at higher penetration levels. We evaluate this in two series of scenarios: (a) substituting CTs with emergency DR that is call-limited, at DR penetration levels of 0%, 5%, 10%, 15%, and 20%; and (b) substituting CTs with economic DR that is not call-limited but rather dispatched based on bid price at the same range of DR penetration levels. For emergency DR, we also test the impacts of varying the dispatch limit. In the following sections we discuss: (1) the reliability implications of relying more heavily on emergency DR; (2) the economic implications of higher emergency DR penetration; and (3) the economic implications of higher economic DR penetration.

1. Reliability Value of Emergency Demand Response

In this section we evaluate how the assumed 100-hour dispatch limit reduces the resource adequacy value of Emergency DR resources, particularly at higher penetration rates. The impact of a particular call-hour limit can be understood by considering the load duration curve for the top 10% to 15% of hours as shown in Figure 22. The chart shows the 400 highest-load hours in the weather-normalized year, a mild-weather year, and a high-load year. The horizontal lines show the maximum load that can be supported solely with traditional generation resources at various levels of DR penetration. As the DR level increases from 0% up to 20% of peak load, the quantity of installed generation decreases and the maximum load that can be supported without DR calls decreases.

Figure 22
Approximate Emergency DR Dispatch Hours at Varying DR Penetration Levels



Notes:

The chart is indicative of the expected quantity of DR calls but is imprecise because it does not account for the (generally offsetting) effects of generation outages, import availability, or load forecast error. See also Figure 23, which accounts for all of these factors.

The chart shows that, even without considering the impact of economic uncertainty, at a 10% DR penetration level the 100-hour dispatch limit of Emergency DR resources would be exceeded in extreme weather years. As the red dots on the chart show at 10% penetration, Emergency DR resources would be need to be dispatched approximately 5, 50, or 122 hours under mild, normal, or extreme weather respectively. At 15% DR penetration, the 100-hour dispatch limit would be exceeded even under normal weather, and with 20% DR penetration the 100-hour limit would be exceeded even with mild weather. In other words, at DR penetration levels of more than 5%, the resource adequacy value of adding more dispatch-limited DR will deteriorate rapidly unless the call limits are increased substantially.

Most regions have historically been able to rely on Emergency DR with similar or lower call-hour limitations because: (a) DR penetration levels have not exceeded approximately 5–7% in most regions; and (b) many regions across North America have enjoyed surplus generation conditions with reserve margins greater than 20%, or well above their reserve margin targets.[119] We simulate regions at their target planning reserve margins and with higher DR penetration

[119] See IRC (2009), p. 26, and NERC (2011a).

levels, which consequently requires DR to be dispatched more frequently than has been the industry experience in recent years.

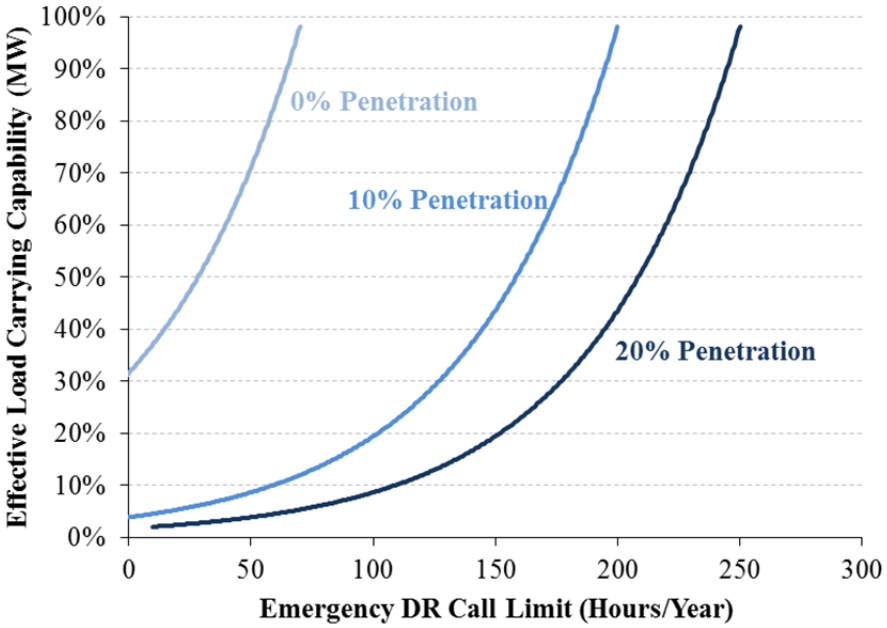
Figure 23 shows the effective load carrying capability (ELCC) of Emergency DR resources. The ELCC of Emergency DR increases with the dispatch price and decreases at higher DR penetration levels. We calculate ELCC as in Section III.B.4 above by determining the quantity of Emergency DR that would have to be added to achieve the same reduction in LOLE as adding a fully-dispatchable traditional CT. The chart shows that even at a 0% penetration level, DR with a dispatch limit of only 10 hours per year has a capacity value only approximately 30% of an equally-sized CT. This is because, even with very low penetration levels, the 10-hour dispatch limit would be exceeded significantly under outcomes with high economic growth or very hot weather.

Under the Base Case assumption with a 100-hour call limit, Emergency DR has an ELCC of approximately 100% at the 0% penetration level, 18% at 10% penetration, and only 8% at 20% penetration. The figure also shows that to maintain 100% ELCC, the call limit would have to be increased to 190 hours at 10% penetration and 250 hours at 20% penetration.

These results also show that, as long as DR penetration levels are low, a system operator does not necessarily need to consider the risk of exceeding dispatch hour limits. However, at higher penetration levels, reliability can only be maintained at criterion if: (1) Emergency DR resources are awarded a lower capacity value for the purposes of calculating their contribution to the reserve margin; or (2) Emergency DR resources are required to increase their call-hour limit. Some regions may implement a combination of these options as DR penetration increases in order to accommodate different types of DR that have more or less callability, as has been done in PJM. PJM now allows DR resources to participate either as dispatch-limited DR that may earn lower capacity payments or unlimited DR that can earn full capacity payments.[120]

[120] For a discussion of these multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

Figure 23
Emergency DR's Effective Load Carrying Capability
(Varying DR Penetration and Call Hours)



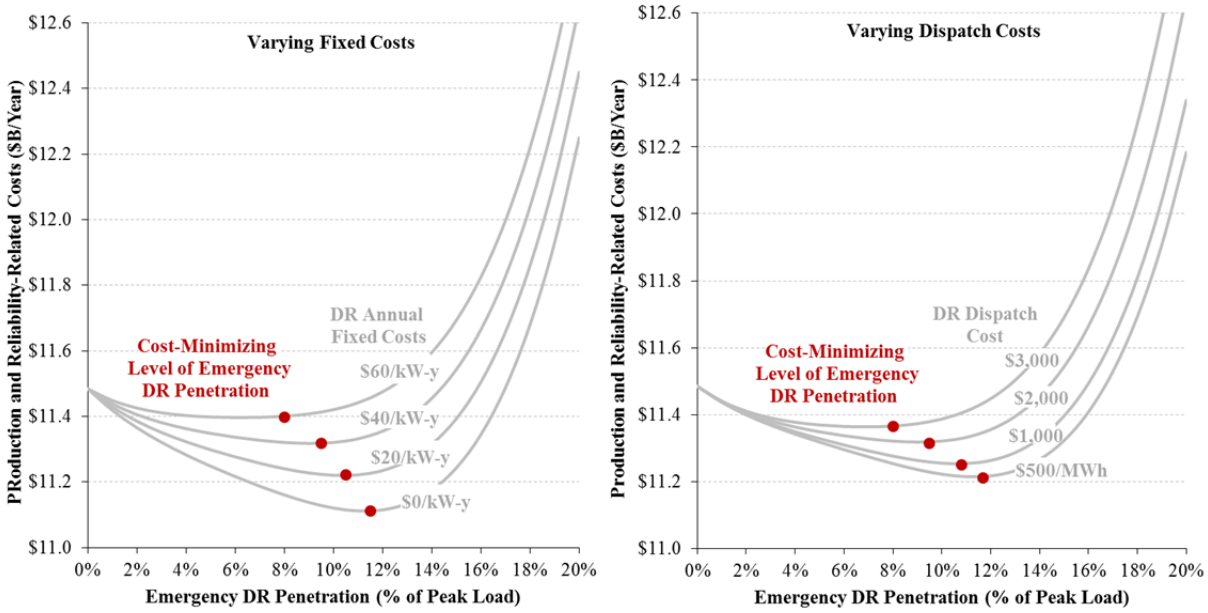
Notes:
Study RTO reserve margin fixed at 15% with CTs displaced by increasing DR.
ELCC of 25% indicates that 4 MW of DR would be needed to achieve the same reduction in LOLE as adding 1 MW of CTs.

2. Cost-Minimizing Level of Emergency Demand Response Penetration

At higher penetration levels, the incremental value of adding Emergency DR drops from a cost perspective, as well as from a reliability perspective. We illustrate this in Figure 24, which shows Study RTO production and reliability-related costs as the Emergency DR penetration level increases (and installed generation levels consequently decrease). The chart shows total costs under: (a) varying *fixed-cost* assumptions for DR ranging from $0/kW-year to $60/kW-year (on the left); and (b) DR *dispatch-cost* assumptions ranging from $500/MWh to $3,000/MWh (on the right).

As shown in Figure 24, beginning at 0% DR penetration total costs initially decrease when adding more DR because these resources have lower capital costs than the CTs that they replace. Even though Emergency DR has a much higher dispatch cost than the displaced CTs, the number of dispatch hours is low enough that it is advantageous to continue adding more DR. However, at higher penetration levels the number of dispatch hours becomes a limiting factor and it is no longer cost-effective to continue replacing CTs with more DR. Overall, and depending on the assumed capital costs and dispatch hours, the cost-minimizing level of Emergency DR ranges from approximately 8% to 12% of peak load as indicated by the red dots.

Figure 24
Production and Reliability Costs vs. Emergency DR Penetration
(Risk-Neutral, Cost of Service)



Notes:
Study RTO reserve margin fixed at 15% with increasing DR offset by reductions in CTs.
Left chart assumes DR dispatch cost of $2,000/MWh; right chart assumes DR fixed costs of $15/kW-yr.

Note that the optimal level of DR penetration is also dependent on the planning reserve margin, which we assumed to be 15%. If the target reserve margin were higher, then higher DR penetrations could be achieved without incurring as many dispatch hours. As a result, the optimal penetration level would be higher. Higher dispatch limits would also increase the optimal penetration levels because Emergency DR, while still a high-dispatch-cost resource, would be able to displace even higher-cost emergency procedures during more hours.

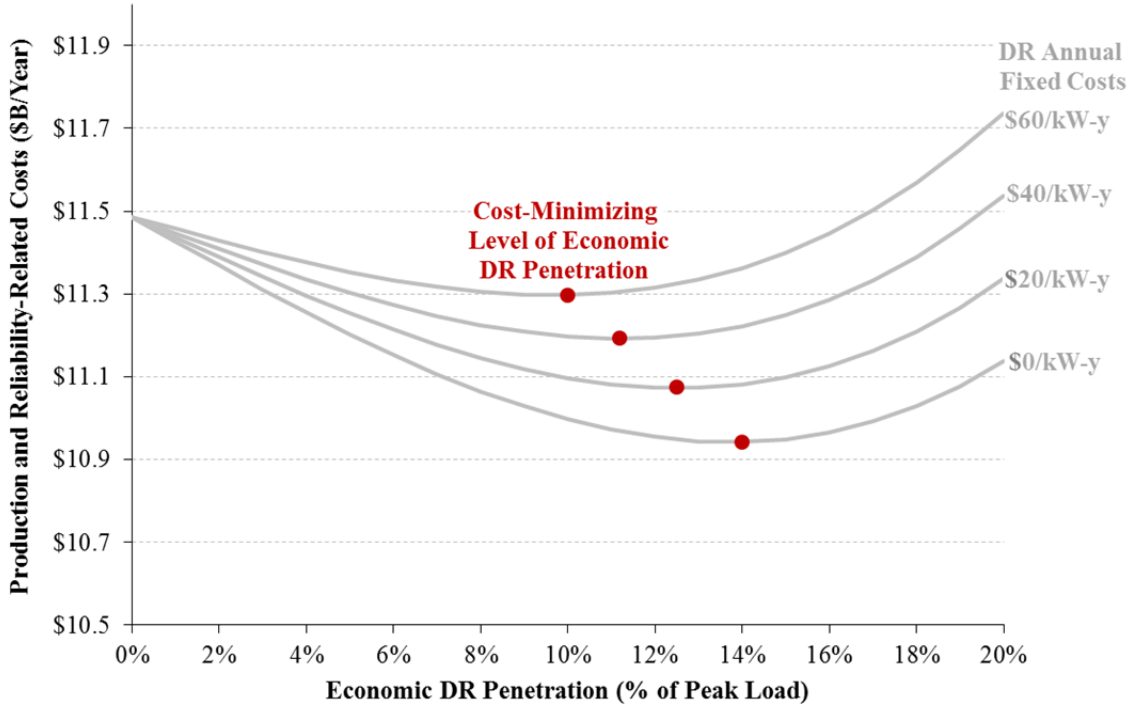
The simulation results highlight the complex role of demand response in reliability planning. DR penetration levels, the design of the products (including dispatch limits and price), and the system load shape all affect the economic and reliability value provided by these resources. The results also show that DR products have to be defined carefully to provide maximum system reliability and economic benefit as customers will only participate in these programs if they are adequately compensated for the fixed and dispatch costs they incur. Ultimately, whether a reasonably efficient portfolio of DR resources will be attracted will depend on: (a) the level of flexibility provided to DR suppliers in defining their own dispatch prices and call-hour limits; and (b) the efficiency of the combined energy and capacity market incentives provided as discussed further in Section IV.C below.

3. Cost-Minimizing Level of Economic Demand Response Penetration

Figure 25 shows the Study RTO production and reliability-related costs as a function of the Economic DR penetration level. The chart is very similar to that shown in the previous section for Emergency DR. As with Emergency DR, adding Economic DR reduces total system costs by

displacing CTs with higher capital costs. However, Economic DR is more valuable than Emergency DR in our simulations because: (a) a substantial portion of the Economic DR is assumed to have lower dispatch costs than Emergency DR; and (b) Economic DR is not call-limited. For these reasons, the optimal level of Economic DR penetration ranges from approximately 10% to 14%, depending on the assumed annual fixed costs. However, this level of Economic DR penetration can only be achieved if a sufficient quantity of potential DR resources are willing to participate in the energy markets at the price levels assumed in our simulations (as described in Section II.C.4 above). We further explore the energy and capacity market design implications of high DR penetration levels in Section IV.C below.

Figure 25
Production and Reliability Costs vs. Economic DR Penetration
(Risk-Neutral, Cost of Service)



Notes:
Study RTO reserve margin fixed at 15% with increasing DR offset by reductions in CTs.
Economic DR dispatch costs are set according to the DR energy supply curve from Section II.C.4 above.

D. Comparison of Reserve Margin Targets

The preceding sections evaluated the reliability and economic implications of a wide range of study assumptions and system conditions and explained how different reliability and economic objectives would lead to different planning reserve margins. Table 11 provides a brief summary of these results, including the sensitivity of the "optimal" (risk-neutral, cost-of-service) reserve margin to various economic assumptions. Table 12 summarizes the reliability-based and economically-based reserve margins under various system characteristics.

As Table 11 shows, the risk-neutral, economically-optimal planning reserve margins could vary by several percentage points under a range of reasonable cost and other economic study

assumptions. For example, different reasonable assumptions for emergency event costs correspond to planning reserve margins ranging from 9.2% to 12.1%. Although this range is substantial, it may be surprisingly small given that the actual cost of emergency events is poorly understood and quite uncertain. Note, however, that the impact of the assumed VOLL, representing the costliest emergency intervention of curtailing firm load, has only a modest impact. Varying VOLL over a wide range from $3,750 to $15,000/MWh results in an economic reserve margin ranging only from 10.0% to 11.6%.

Other important economic assumptions that also affect the optimal reserve margin include: (1) the forward planning period, resulting in planning reserve margins ranging from 9.4% to 11.0% for forward planning periods from two to six years; (2) the CT CONE, resulting in planning reserve margins ranging from 9.5% to 11.0% for CONE values from $100 to $140/kW-year; and (3) the ownership of transmission rights, resulting in planning reserve margins ranging from 8.3% to 12.3% depending on whether the importer owns rights (allowing it to buy power at the lower external price) or the exporter owns rights (allowing it to sell power at the higher external price).[121]

Table 11
Sensitivity of Economically Optimal Reserve Margin to Economic Study Assumptions
(Risk Neutral, Cost-of-Service Perspective)

	Reserve Margin Range *(% ICAP)*	**Base Case**	**Low/High Sensitivity**
Base Case	10.30%	n/a	n/a
Emergency Event Costs			
Emergency Generation	10.2% - 10.5%	$500/MWh	$250 - $1000/MWh
Emergency DR	9.9% - 10.9%	$2000/MWh	$1000 - $3000/MWh
Emergency Hydro	10.2% - 10.5%	$3,000/MWh	$1,500 - $6,000/MWh
Voltage Reduction	10.2% - 10.4%	$7,000/MWh	$3,500 - $14,000/MWh
VOLL	10.0% - 11.6%	$7,500/MWh	$3,750 - $15,000/MWh
All Emergency Event Costs	*9.2% - 12.1%*	*Base*	*50% or 200% Base*
Other Assumptions			
Load Forecast Error	9.4% - 11.0%	4 Years Forward	2 Years - 6 Years
CONE	9.5% - 11.3%	$120/kW-y	$100 - $140/kW-y
Transmission Ownership	8.3% - 12.3%	50/50 Ownership	Importer/Exporter Owns

Notes:
Study RTO "optimal" reserve margin from the risk-neutral, cost-of-service perspective.
Impact of economically-determined planning reserve margin on various economic sensitivities.

Table 12 summarizes the reliability-based and economically-based reserve margin targets under the Base Case scenario as well as under each of the alternative simulation cases we examined in

[121] See Sections III.A.5 and III.A.2 for additional discussion of forward period and transmission rights assumptions.

the preceding sections. We also show the results from the simulation cases with $3,000/MWh and $1,000/MWh price caps, which we discuss in the context of market design in Section IV of this report. Generally, these results show that differing system size, topology, and other conditions can substantially impact planning reserve margin targets. For example, maintaining a 0.001% Normalized EUE reliability standard could require a reserve margin anywhere from 7.5% up to 15.8% depending on the assumed system topology, size, and other characteristics. Similarly, economically-optimal, risk-neutral reserve margins could vary anywhere from less than 6% to 16.5% for both cost-of-service and societal perspectives.

Nevertheless, changing system characteristics has similar directional impacts on reserve margin targets for all resource adequacy criteria, both in terms of physical reliability and economics. For example, the Island Case always requires higher planning reserve margins because the system is not able to rely on neighbors for any resource adequacy support. Similarly, the Long Neighbors Case always allows for lower planning reserve margins in the Study RTO due to the greater availability of neighbor support.

Table 12
Reliability-Based and Economically-Based Reserve Margin Targets
(Across Base and Sensitivity Case Simulations)

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
Lower Price Caps					
$1,000 Price Cap Case	15.2%	8.2%	9.6%	8.7%	7.9%
$3,000 Price Cap Case	15.2%	8.2%	9.6%	9.5%	7.9%
Smaller System Size					
40% Size Case	14.8%	<6%	7.5%	<6%	<6%
40% Size and Transmission	15.1%	6.9%	8.1%	<6%	<6%
Neighbor Assistance					
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

IV. MARKET DESIGN IMPLICATIONS

Up to this point, we evaluated only the reliability and economic implications of different planning reserve margins, system conditions, and resource penetration levels with respect to annual system costs. Much of that analysis is relevant irrespective of market design and whether generation resources are cost-of-service regulated or restructured. However, the ability to achieve a particular planning reserve margin, as well as the economic implications for customer costs, supplier returns, and market prices, cannot be evaluated without considering the market design of the study region. In cost-of-service regulated environments, resource adequacy is achieved through integrated resource planning and supported by rate recovery for all approved investments in generation. In market-based environments, investments can only be attracted if prices are high enough on average for suppliers to earn a sufficient return on their investments.

In this section, we evaluate the implications for both customers and suppliers with respect to: (a) energy-only markets that do not have a reliability requirement and whose reserve margin is determined by the quantity of resource investments that can be attracted by revenues from the region's energy and ancillary services (A/S) markets; (b) capacity markets that *do* have a planning reserve margin standard, with supply investments attracted by a combination of energy, ancillary service, and capacity market revenues; (c) the implications of integrating high levels of demand response into energy-only and capacity markets; and (d) a comparison of customer and supplier impacts under various energy-only and capacity market designs.[122]

A. ENERGY-ONLY MARKETS

Restructured markets, including both energy-only markets and regions that rely on capacity markets, can only attract investments in needed resources if prices are high enough on average that suppliers can expect a sufficient return on their investments. In "energy-only" markets, there is no mandatory minimum reserve margin. In these markets, including Texas, Alberta, Australia's NEM, and Scandinavia, the reserve margin achieved depends on the market prices for energy and ancillary services, with new generation being built only when suppliers believe that their investments can earn their cost of capital. In other words, there is no guarantee that enough generation will be built to maintain a certain reserve margin or resource adequacy level on average.[123]

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[122] In the following sections, we briefly explain the major features and differences between energy-only and capacity markets, but stop short of a full theoretical treatment. For a more comprehensive survey of market designs for resource adequacy, we refer the reader to Pfeifenberger, Spees, and Schumacher (2009); and Spees, Newell, and Pfeifenberger (2013).

[123] Most so-called "energy-only" markets also rely on some reliability backstops to prevent unacceptably low reliability events. For example, Scandinavian markets maintain "strategic reserves" of usually high-cost, older capacity that is only dispatched under emergency conditions at very high prices (*i.e.*, with market prices approximately reflecting a world in which those strategic reserves did not exist at all). Similarly, Texas regularly procures demand response supplies that are to be deployed only during emergency conditions. Many markets, including Texas and Alberta for example, also have mechanisms for administrative intervention into the markets if reliability is expected to drop to very low levels. See Pfeifenberger, Spees, and Schumacher (2009), pp. 28-29; AESO (2008); European Commission (2012), p. 8.

In this section, we evaluate the economic and reliability implications of resource adequacy within energy-only markets, including: (1) how the equilibrium reserve margin is determined within energy-only markets; (2) the preconditions that are necessary in order for the equilibrium reserve margin to reflect the socially optimal level; (3) the volatility in energy market returns that suppliers would have to expect in an energy-only market; (4) the impact of different system conditions and modeling assumptions; and (5) the "missing money" problem that can cause energy-only markets to fail to attract investments sufficient to meet system operators' or policy makers' reliability objectives.

1. Economic Equilibrium at the Cost of New Entry

In energy-only markets, system operators are not able to mandate a minimum planning reserve margin. Instead, the reserve margin achieved within an energy-only market depends on market prices and on suppliers' expected returns. As shown in Figure 26 for the Base Case simulations, the energy margins that a new gas CT would expect to earn on average in the Study RTO are a downward-sloping function of reserve margin. We show energy margins relative to the CONE value of a CT that reflect the average annual *net revenues* required to recover investment and fixed costs over the economic life of the plant.[124]

The figure shows that average annual energy margins are high at very low reserve margins because tight supply conditions create high energy prices and more frequent price spikes. Under such conditions, an energy-only market would attract additional investments because suppliers would expect to earn on average more than enough in the energy market alone to recover their fixed costs. As the market attracts more investments and reserve margins increase, energy prices and supplier returns decline. The energy-only market will continue to attract incremental investments until energy margins drop to CONE, which represents an equilibrium point for achievable reserve margin. No additional investment would be attracted beyond this point because investors would not expect to recover their costs of new entry.

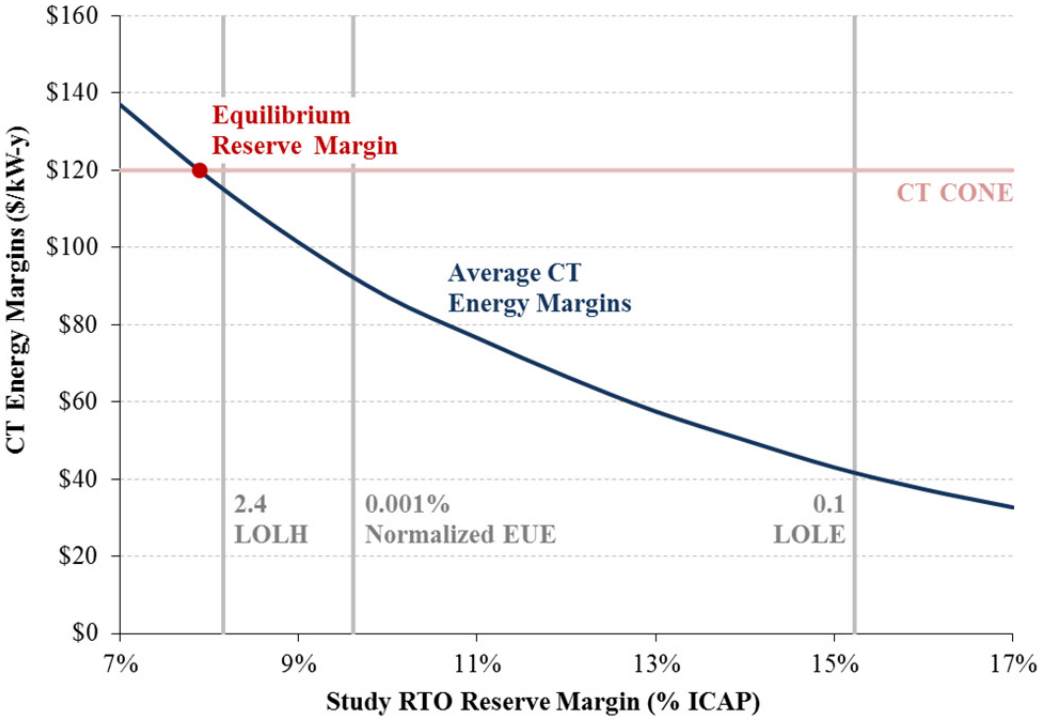
In our Base Case simulations, the Study RTO would achieve an economic equilibrium reserve margin of 7.9% in the Study RTO (which corresponds to a 16.5% reserve margin over the combined four-system area, as explained in Table 7 in Section III above). This economic equilibrium is indicated by the red dot in Figure 26. Note, however, that because the achieved reserve margin is determined entirely by market forces, there is no guarantee of achieving any specific resource adequacy level in an energy-only market. In our hypothetical system, the economic equilibrium reserve margin is lower than the reserve margin that would be required to maintain a typical reserve margin of 15.2% under the 0.1 LOLE standard, 8.2% under the 2.4 LOLH standard, or 9.6% under a 0.001% Normalized EUE standard.

Finally, we note that to illustrate this equilibrium reserve margin result, we assumed that a natural-gas-fired CT is the marginal technology over the entire range of reserve margins. A more precise determination of equilibrium conditions would evaluate not only the equilibrium reserve margin but also the equilibrium resource mix. A system in disequilibrium would

[124] We refer to "net revenues" as the revenues earned in energy and ancillary service markets net of the plant's variable operating and maintenance costs. Our simulation results show only net energy revenues as they do not separately consider ancillary service markets and associated revenues.

experience entry (or exit) of the most profitable (most uneconomic) types of assets from among many asset classes, and would reach true equilibrium at a particular reserve margin with a particular resource mix. We do not evaluate equilibrium resource mix in our study, but note that actual power markets will always experience at least some disequilibrium due to changing system conditions, regulations, and supplier expectations over time.

Figure 26
CT Energy Margins vs. Study RTO Reserve Margin



Notes:
CT energy margins in the Study RTO are from the Base Case simulation.

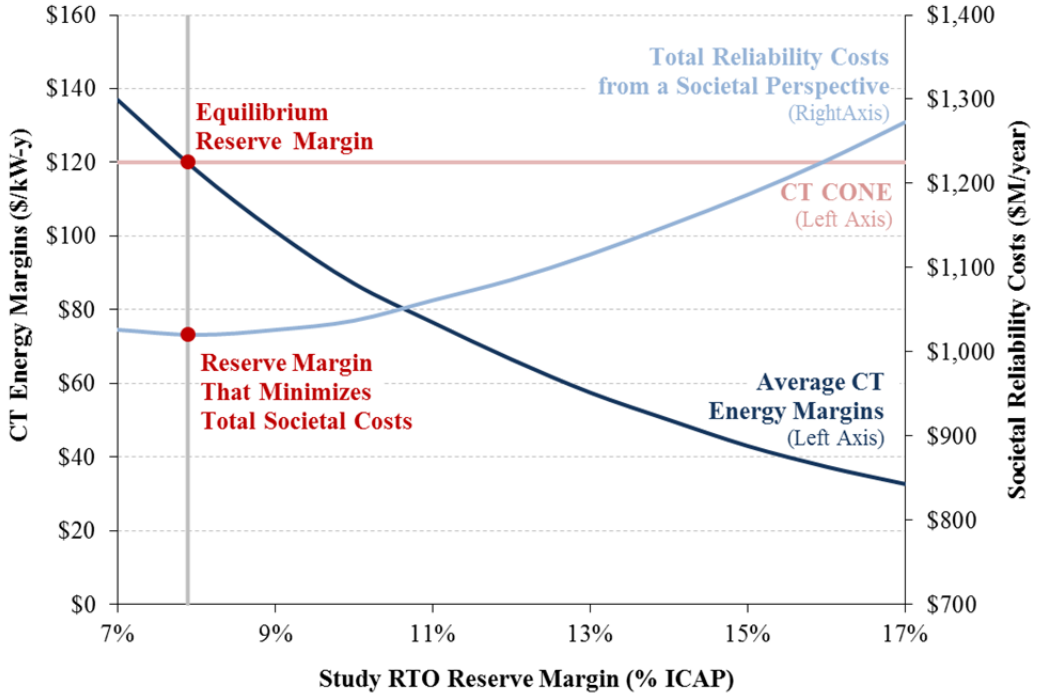
2. Conditions for Achieving Socially Optimal Investment Levels

The most important benefit of energy-only markets, compared to other market designs for resource adequacy, is that energy-only markets theoretically can attract the optimal, welfare-maximizing level of investments from a societal perspective. This is because prices in a perfectly-designed energy-only market will always reflect the marginal system cost defined by the intersection of supply and demand. This means that customers are able to choose how much reliability for which they are willing to pay. For example, some customers place a relatively low value on reliability, and so would rather reduce consumption than pay the $3,000/MWh price realized when emergency hydro resources need to be dispatched in our simulations. Other customers place a high value on service and so will be willing to pay the $7,000/MWh price incurred when implementing voltage reductions. In such a perfectly-designed energy-only market, the decisions of suppliers, customers, and the system operator will all be made relative to the marginal societal costs and benefits of their actions.

We show CT energy margins relative to CONE for our Study RTO Base Case in Figure 27. The figure, which assumes risk neutrality for all market participants, shows CT energy margins

relative to CONE (left axis) and total annual societal reliability-related costs (right axis).[125] As explained in the previous section, the energy-only market will achieve an equilibrium reserve margin of 7.9%. This is also the reserve margin that will minimize total societal costs as tabulated in Section III.A.3 above.[126]

Figure 27
CT Energy Margins vs. Study RTO Reserve Margin and Societal Costs



Notes:
CT energy margins vs. societal reliability costs in Study RTO from Base Case simulation.
See Section III.A.3 for the derivation of risk-neutral, societal reliability-related costs.

The reason that an energy-only market can achieve this outcome is that a perfectly-designed energy market will produce hourly energy prices equal to true marginal system costs.[127] During

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[125] The reader may note that we now shift from a discussion of "societal welfare-maximizing" reserve margins to a discussion of "societal cost-minimizing" reserve margins. We make this change as a matter of simplicity and convenience, since the objectives of "maximizing welfare" and "minimizing cost" are identical in a system with inelastic demand like our Study RTO. We do not ignore the possibility of elastic demand however, but instead account for net impacts on customer welfare indirectly by tabulating the "costs" imposed by dispatching economic DR, emergency DR, and involuntary load shedding. An alternative approach in which we calculate total societal welfare directly (consumer surplus plus producer surplus) would be more conceptually pure, but would unnecessarily complicate our discussion.

[126] Note that this reserve margin does not have any pre-determined relationship to the reserve margin that minimizes costs from a utility cost-of-service perspective as evaluated in Section III.A.2 above.

[127] The perfectly-designed market will also attract the optimal proportion of baseload, intermediate, and peaking units for the same reason that it would achieve the optimal reserve margin. In each case, for baseload as well as peakers, the net revenues available from the market will be equal to the net societal value created by displacing higher-cost resources or emergency actions. This means that baseload units will have sufficient incentives to enter the market only if the net societal value they create is equal to or

Continued on next page

most hours, marginal system costs are equal to the production costs of the highest-cost generation or demand response asset dispatched to meet load. During peaking and scarcity events however, marginal system costs rise to higher levels driven by the marginal cost of emergency procedures such as calling emergency DR, emergency generation, emergency hydro, operating reserves shortages, voltage reductions, or load curtailments. This means that the profit that a new generating plant earns in a particular hour is exactly equal to the marginal reduction in the societal costs that it provides.[128] If the reduction in total annual system costs is greater than the marginal unit's total annual capital and fixed costs at CONE, then total societal costs will be reduced by that investment and suppliers have an incentive to enter the market.

As promising as these theoretical benefits sound, we stress that actual power markets cannot be expected to achieve the optimal reserve margin in all cases. We are able to demonstrate the result in our simulations only because we have constructed a carefully-designed scarcity pricing mechanism to ensure that our simulated energy prices are always exactly equal to marginal system costs. Achieving such perfect energy prices that exactly equal marginal system costs is difficult if not impossible under real-world conditions. If those imperfections cause energy prices to be too high on average, the market will attract more than the optimal level of investments and will achieve a higher reserve margin. Of greater concern to most regulators and suppliers is the possibility of the opposite outcome in which energy prices and the resulting reserve margins are too low, a topic that we discuss further in Section IV.A.4 below.

There are three types of factors that make it difficult to set prices perfectly in wholesale electric markets. First, there is insufficient integration of price responsive demand in wholesale electric markets, because most customers pay only a fixed price for energy and so have no incentive to respond to wholesale market conditions. Even among customers that do participate in wholesale DR programs or retail pricing that encourages price response, their willingness to pay for energy may not be fully incorporated into wholesale energy market prices due to the DR program design, technical challenges in price formation, or lack of enabling technology. Second, in circumstances when operator interventions are needed to address emergency conditions, prices can be artificially suppressed by the "additional supply" that the intervention creates (*e.g.*, by dispatching emergency DR or implementing a voltage reduction). Several RTOs are working on

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greater than their investment costs. There is also a displacement effect among resources in that adding 1 MW of baseload would reduce net revenues to CTs, and adding 1 MW of CTs would reduce net revenues to baseload (although by a lesser amount). Overall, one would expect an investor to add the most profitable resource type at any given time in a way that moves the system toward an optimal equilibrium reserve margin and resource mix. Again, any deviations from perfect pricing that reflects marginal system costs will not only cause the equilibrium reserve margin deviate from the optimal reserve margin, but it will also cause the resource mix to deviate from the optimal resource mix.

[128] For example, consider the impact of adding a very small 1 MW CT with production costs of $62.50/MWh as in our Base Case. In an hour when load shedding would be required in the absence of the CT, the reduction in societal costs is equal to: (a) the reduction in unserved energy, times the VOLL, or 1 MWh times $7,500/MWh; minus (b) the increase in total production costs incurred by dispatching the CT, or 1 MWh times $62.50/MWh. This reduction in total societal costs is also equal to the hourly energy margins earned by the CT which is the hourly price minus production cost (*i.e.*, price at $7,500/MWh minus cost at $62.50/MWh).

efforts to prevent such price suppression, but these efforts are still ongoing. Finally, if an RTO opts to set administratively-determined scarcity prices to prevent price suppression during emergency events, it is a remaining challenge to determine the correct price for these events, such that the administrative price is reflective of the marginal cost of the reliability interventions. These are challenges that energy markets across North America are currently addressing as they attempt to improve their pricing mechanisms, particularly during scarcity hours.[129]

3. Volatility in Supplier Energy Margins

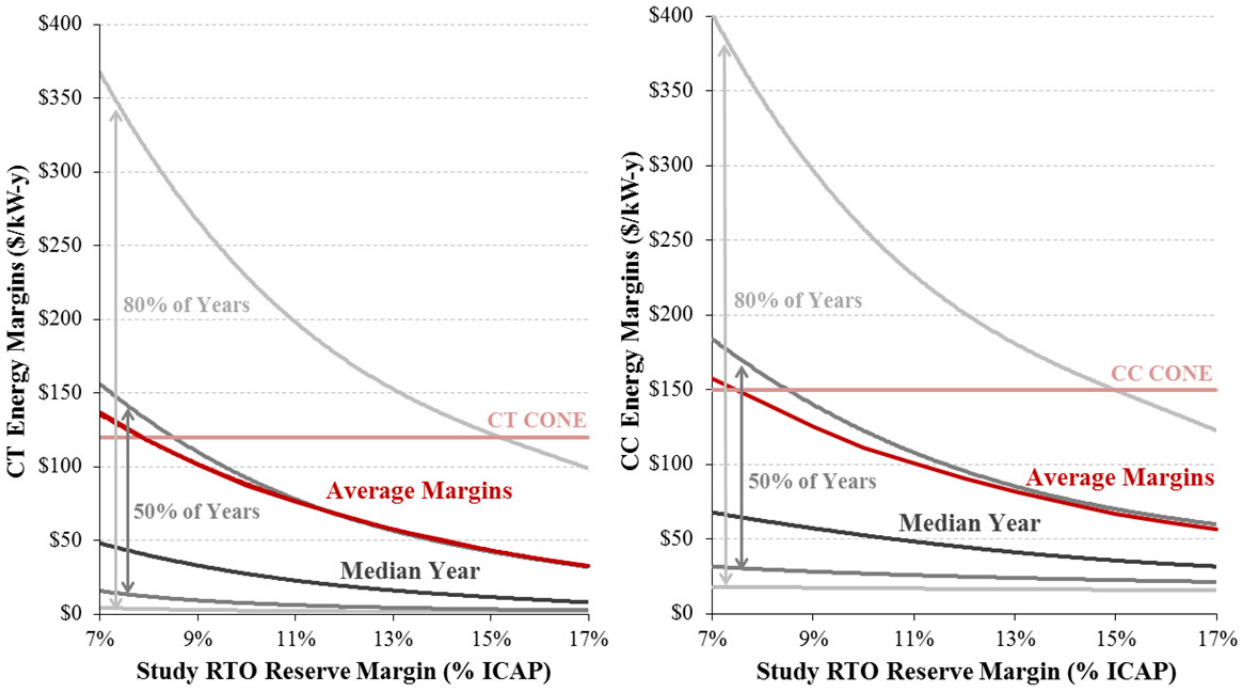
Figure 28 summarizes annual energy margins earned on average for a new CT (on the left) and a new CC (on the right) at different reserve margins. The figure also shows the range of annual energy margins that would be realized in spot energy markets due to uncertainties such as weather, load growth, hydro conditions, or outages. The annual average of energy margins reflects the expected value across all 9,600 simulations for each reserve margin.[130]

To demonstrate the year-to-year volatility in supplier returns for an unhedged supplier, we also show the spot energy margins that a new unit would earn in the median year, along with the middle 50% of all years (the range between the 25th and 75th percentiles) and the middle 80% of all years (the range between the 10th and 90th percentiles). The median energy margin is representative of a "typical year" in the sense that there is a 50% chance that the actual energy margins will be above or below that value. The 90th percentile (top gray line) is particularly interesting, as it approximately represents a "once in ten years" event in which suppliers could earn more than these energy margins due to unusual tight supply or high load conditions.

[129] For a more comprehensive discussion of scarcity pricing mechanisms, including how the energy-only markets of Alberta and Texas are addressing these and other challenges, see Newell, *et al.*(2012),Section V.A.2; Pfeifenberger, *et al.* (2009), Section IV; and Pfeifenberger, *et al.* (2011a, 2013).

[130] As discussed in Section II.A, each of the 9,600 simulations for the Base Case and Change Cases estimates hourly reliability and economic system results for a full calendar year, with each of the 9,600 simulations representing different load shapes, economic forecast uncertainties, hydro conditions, unit outages, *etc.*

Figure 28
Volatility in CT (left) and CC (right) Energy Margins vs. Reserve Margin



Notes:

CT and CC energy margins the Study RTO are from the Base Case simulation.

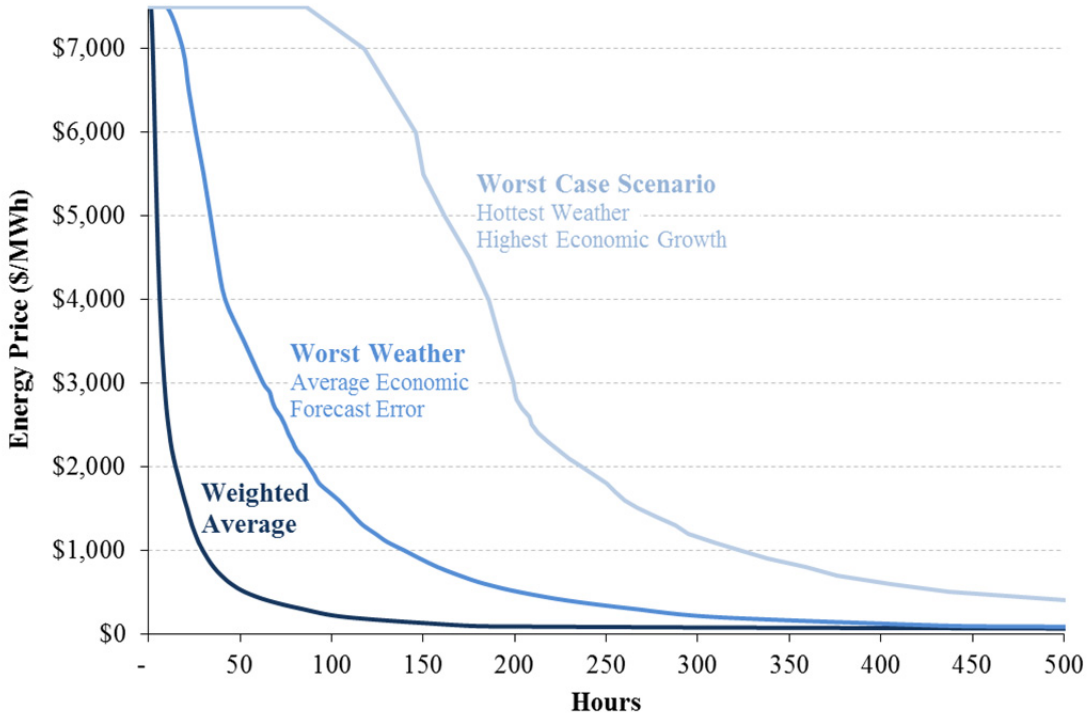
Gray lines represent the 10th, 25th, 50th, 75th, and 90th percentile estimates of spot energy margins (*i.e.*, net revenues earned in spot energy market without forward contracting or other risk mitigation).

These results for CTs' and CCs' annual energy margins show that year-to-year volatility in supplier returns is quite large. For example, assuming no forward contracting, at the 7.9% equilibrium reserve margin at which a new CT will earn CONE on average across all years, we estimate that the plant would earn only approximately $30/kW-year (30% of CONE) in the "typical" year. However, the CT would earn more than $260/kW-year (more than twice CONE) approximately once in a decade. Similarly, the figure shows that at the equilibrium reserve margins where a new CC earns its CONE on average across all years, the plant would earn only approximately $55/kW-year (38% of CONE) in a typical year, although the plant would earn more than $290/kW-year (more than almost twice CONE) once in a decade.

Figure 29 further illustrates spot energy market volatility by comparing three annual price duration curves at the equilibrium, the 7.9% reserve margin level. The first price duration curve is based on the weighted average across all 9,600 annual simulations (dark blue line) while the lighter blue lines illustrate a worst weather scenario (medium blue) and a worst weather combined with highest load growth scenario (light blue). On average over the years, spot energy prices would rise to high levels above $1,000/MWh only approximately 35 hours per year, while prices would rise above $1,000/MWh in approximately 140 hours under the worst weather year (and the weighted average of economic growth forecasting errors) and in approximately 325 hours in the worst case scenario that combines the worst weather year with the highest unanticipated load growth. Note that one would not expect prices this high in many markets even under such a worst case scenario, since many markets maintain reserve margins that are

much higher than the 7.9% shown in the figure and also have lower price caps than the $7,500/MWh utilized in our Base Case simulations.

Figure 29
Price Duration Curve at the 7.9% Equilibrium Reserve Margin



Notes:
Study RTO Base Case Price duration curve on average and in extreme weather and load growth cases.

The reason that, in the absence of forward contracting and hedging, supplier energy margins can rise so high relative to their median or even average annual levels is that market prices in most years will be set by the marginal costs of the generation fleet in nearly all hours. However, both our Study RTO and actual energy-only markets will also experience periodic severe price spikes that are driven by scarcity conditions reflecting extreme heat waves or unanticipated high load growth.[131] Under these conditions, market prices can rise to very high levels as the need for high-cost emergency operating procedures increases. Realized prices in our Study RTO rise with the severity of the shortage event according to the scarcity pricing function described in Section II.E above. Prices may reach as high as the VOLL-based price cap of $7,500/MWh in the extreme circumstances when load must be shed. As explained in the previous section, these periodic, severe price spikes are necessary if the energy-only market is to attract the socially-optimal level of investments.

The VOLL-based $7,500/MWh price cap and administrative scarcity pricing function also mean there is great uncertainty around the spot energy margins that power plants would earn and

[131] For a comparison of the frequency and severity of scarcity pricing events in various real-world energy-only markets, see Newell, *et al.* (2012), Section I.B.

customers would need to pay in any particular year in the absence of forward contracting or hedging. Unhedged suppliers would face substantial investment risk under a market environment in which returns in the median year are less than half the returns that would be expected on average over the years. This also means that the energy margins that a plant could have earned in the spot market in a recent year (or even several recent years) are not a good indicator of the average energy margins that plants will likely earn over their economic life. For example, at the equilibrium reserve margin, a CT selling solely into the spot market would earn less than 30% of CONE in half of all years. Further, though not shown at the scale of this chart, in the most extreme 5% of simulation cases (representing a 1-in-20 event that a unit may experience once over its useful economic life) annual CT margins earned in spot markets rise 5.5 times above CONE.

Overall, these results mean that if suppliers relied solely on spot market sales, a substantial portion of total investor returns would be earned in only a small number of extreme years. To mitigate this risk, asset owners typically use a portfolio of hedges or contracts. But the scale of the volatility nevertheless has a number of implications for lenders, equity investors, and policy makers. In particular, extreme price events (even if mostly hedged) have important political consequences that may trigger administrative or legislative interventions, including interventions that could undermine investment signals needed for resource adequacy. The regulatory risk of such potential interventions would require investors to discount the expected value of energy margins earned in such extreme cases, with greater perceived regulatory risk translating to lower realized investment levels in energy-only markets. We examine these and other considerations related to the risks to total supplier returns more fully in other publications.[132]

Note, however, that neither customers nor suppliers are fully exposed to this level of spot price uncertainty. This is because all prudent suppliers and load-serving entities will mitigate a significant portion of these risks through hedging tools, such as forward contracts. Forward contracting will allow entities to lock in anticipated average prices for the future, meaning that while the contract price will exceed the realized spot price most of the time, it will be far below realized spot prices during extreme outcomes. The farther forward a supplier or load-serving entity is able to hedge,[133] the less spot energy market risk exposure the supplier will have. For example, long-term contracts will mitigate nearly all price risks, including risk factors such as economic growth, weather, and outages. However, hedging even a few months forward will mitigate most weather and outage-related risks. Because weather and outage risks are shown to account for the majority of the uncertainty range in our market simulations, even short-term forward contracts (such as seasonal contracts) will be able to hedge a large portion of the uncertainty range shown above.[134] In either case, the weighted average of energy margins will

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[132] We address a number of related questions more extensively in Pfeifenberger and Newell (2011c); and Newell, *et al.* (2012), Section II.

[133] Note that to mitigate uncertainty in spot energy margins, suppliers will need to hedge both their energy market revenues and their fuel costs.

[134] For example, our Base Case simulations show that for the 7.9% equilibrium reserve margin, the uncertainty range between the 10th and 90th percentiles of CT energy margins is $320/kW-year. For normal weather and the weighted average of outage risks (*i.e.*, with exposure only to multi-year economic load growth uncertainty), the uncertainty range between the 10th and 90th percentiles is reduced to $100/kW-year.

not be significantly affected by such hedging activity unless forward contracts sell at a premium above expected average outcomes because buyers are more risk averse than suppliers (or, alternately, at a discount if suppliers are much more risk averse).[135]

The substantial risk mitigation that can be achieved even through seasonal forward contracts is illustrated by the example of ERCOT in 2011 and 2012. The summer weather for 2011 was an example of extreme conditions, while 2012 was milder than normal.[136] Based on stakeholder interviews we conducted for ERCOT in a 2012 study prompted by these extreme events, we learned that both generators and competitive retail suppliers engage in a substantial amount of forward hedging at periods of up to three to five years. On a seasonal forward basis of several months, some retailers even buy hedges sufficient to cover their entire anticipated summer electricity needs. As a consequence, market participants have ample opportunities to mitigate extreme spot prices and are likely to pay or earn prices much closer to the expected average in many years.

Table 13 illustrates the magnitude of risk mitigation through seasonal forward contracting. The table compares seasonal futures prices against realized hourly spot market prices in ERCOT for the Summers of 2011 and 2012. More specifically, the table compares for these two years: (1) the prices for June through September on-peak futures contracts as of April of each year; with (2) the realized on-peak spot prices for the same hours and months.[137] As shown, for the peak months of August 2011 and August 2012, *futures* contract prices for these two months differed by less than $15/MWh or about 20%. In contrast, August on-peak *spot* prices for 2011 and 2012 differed by $175/MWh, or approximately 280% of the average August futures price. This shows that reasonably effective market-based hedging tools are available to market participants who wish to mitigate spot price exposure. How much additional risk mitigation should be achieved by increasing planning reserve margins above the risk-neutral economic optimum is consequently a difficult question that will need to be addressed through additional research.

[135] If buyers are more risk averse they will be willing to pay a premium above expected spot prices to secure a higher level of forward certainty which would then translate into slightly higher supplier returns and realized reserve margins.

[136] See an extensive discussion of the Summer 2011 realized prices, scarcity events, and weather events, as well as our evaluation of impact on investors and buyers in Newell, *et al.* (2012).

[137] Data from Ventyx (2013).

Table 13
Illustration of Risk Mitigation Achieved by Seasonal Forward Contracting

	Futures Traded in April ($/MWh)	Realized Real-Time Spot Prices ($/MWh)	Delta ($/MWh)
Summer 2011			
June	$45.94	$51.66	$5.72
July	$55.71	$58.67	$2.96
August	$55.71	$209.99	$154.27
September	$42.79	$39.68	($3.11)
Summer 2012			
June	$38.11	$38.22	$0.11
July	$70.07	$31.50	($38.56)
August	$70.07	$34.98	($35.09)
September	$38.62	$29.02	($9.59)

Sources and Notes:
Futures and spot prices are for ERCOT North On-Peak prices.
Futures prices are averaged across all trade dates in April of 2011 or 2012, two to six months prior to delivery, from Ventyx (2013).

4. Missing Money and the Impact of Price Caps

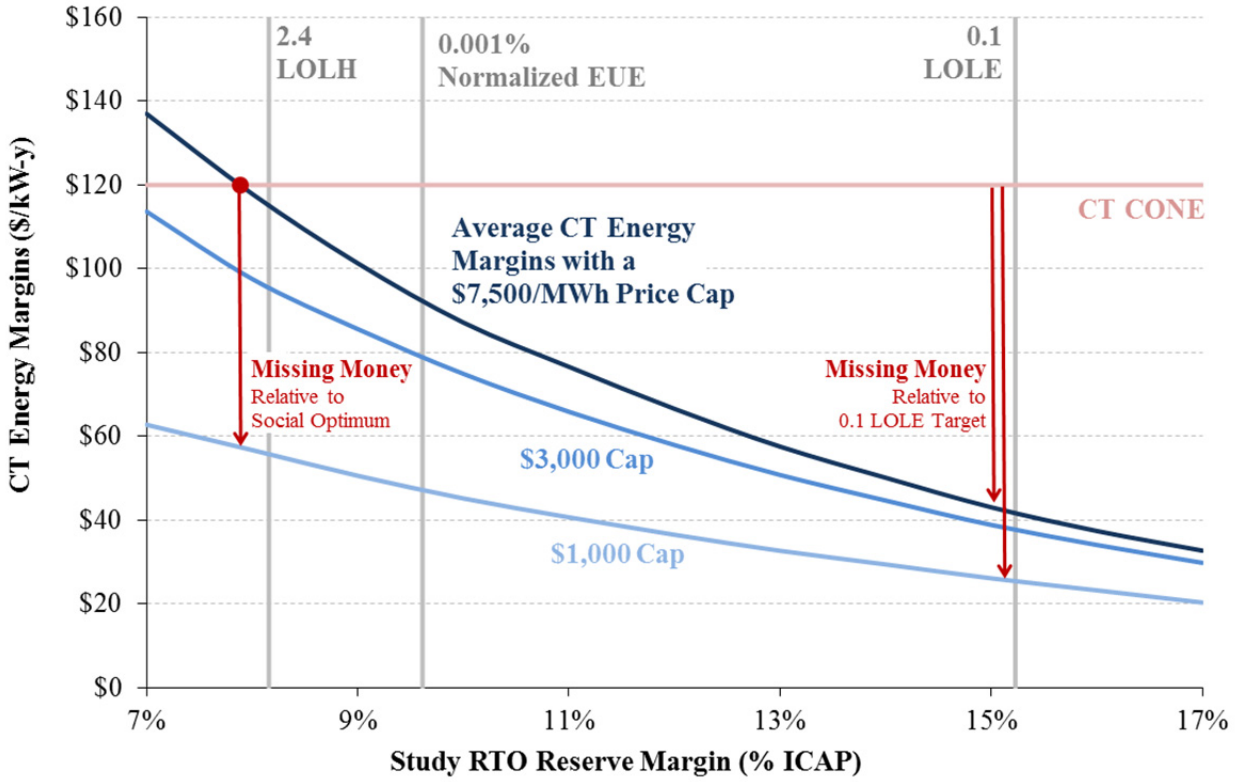
The Base Case assumes that energy prices can rise up to the VOLL-based energy price cap of $7,500/MWh. As explained above, this VOLL-based price cap, combined with an efficient scarcity pricing mechanism tied to marginal system cost creates efficient real-time energy market price signals that accurately reflect the marginal value of supply at all times. In some cases, particularly during extreme scarcity events, these efficient prices can be very high relative to average prices. Imposing a price cap that is far below VOLL or otherwise suppressing prices during scarcity events will have the inefficient effect of suppressing prices and supplier returns below what is needed to achieve the risk-neutral societally optimal investment levels. This creates a so-called "missing money" problem in the energy market.

Figure 30 demonstrates the concept of missing money for the Study RTO in the Base Case Simulation and in two alternative scenarios in which we introduce price caps of $3,000/MWh and $1,000/MWh. At the 7.9% risk-neutral, societal optimum reserve margin, suppliers earn high enough energy margins to sustain investment. However, imposing price caps of $3,000/MWh or $1,000/MWh eliminates the high prices of some events and causes supplier net revenues to drop to only 84% or 49% of CONE respectively. In other words, the price-capped market would have a "missing money" problem of $20 and $62/kW-year respectively, relative to the energy margins needed to sustain the socially optimal reserve margin.

An even greater "missing money" problem exists if policy makers wish to maintain the 15.2% reserve margin needed to meet the 0.1 LOLE reliability standard. In this case, there are two sources of missing money: (1) energy prices that are suppressed by the price caps; and (2) even if price formation is efficient as in the Base Case, the energy-only market does not achieve an economic equilibrium reserve margin at the planning reserve margin (*e.g.*, to achieve 0.1 LOLE)

that regulators may wish to maintain. This topic is the subject of current market reform efforts in Texas.[138]

Figure 30
Energy Margins and "Missing Money" at Different Price Caps



Notes:
Average CT energy margins with price caps of $7,500/MWh (Base Case), $3,000/MWh, and $1,000/MWh.

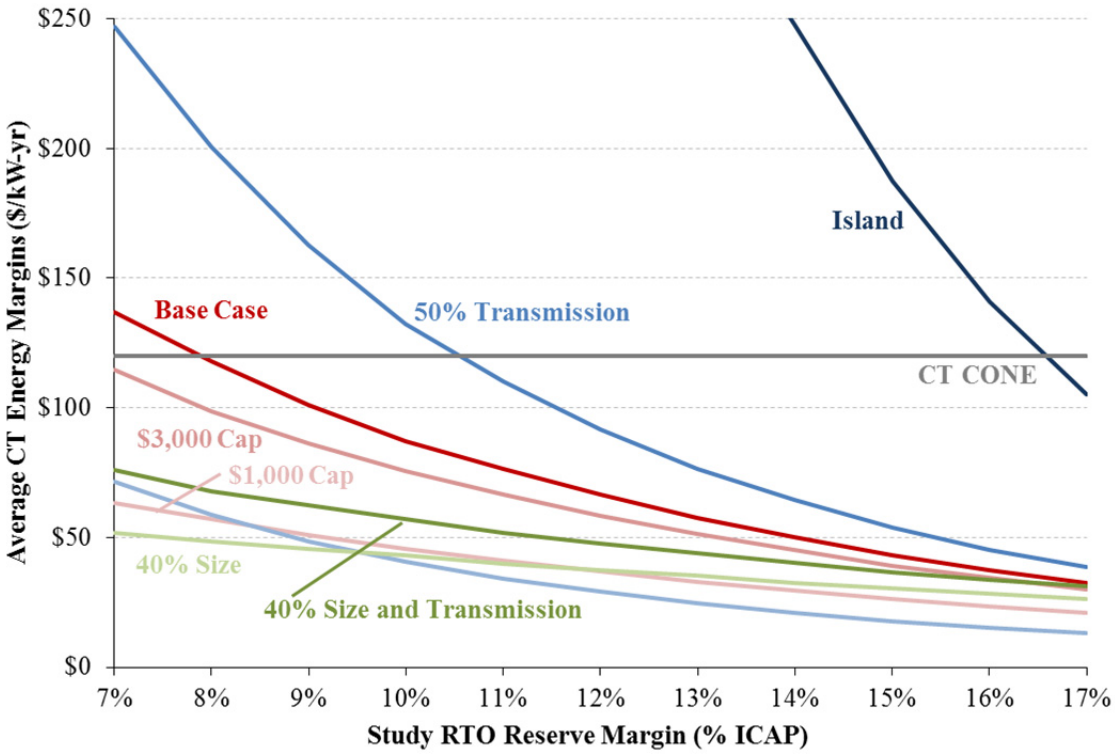
5. Implications of Varying System Conditions and Study Assumptions

Figure 31 shows average CT energy margins for the Base Case and each of the alternative simulation scenarios that we have examined. Compared to the Base Case, large declines in energy margins would be realized under the lower price cap cases (as discussed above), or in any of the scenarios where the Study RTO is able to rely more heavily on imports from the neighboring regions with higher reserve margins. In these cases, under an energy-only market, the Study RTO would realize an economic reserve margin below minimum the 7% level that we have examined. However, note that in cases where energy margins are driven down by increased neighbor assistance, these lower realized internal reserve margins may not necessarily cause any additional reliability concerns since the Study RTO is also in a better position to rely on physical neighbor assistance during these events.

[138] See Newell, *et al.* (2012), Sections I.D-F.

The largest increases in CT energy margins are caused by reduced transmission interconnections with neighboring regions. In fact, the 50% Transmission and Island Cases would increase supplier returns sufficiently to increase the Study RTO's equilibrium reserve margin to 12.3% and 16.5% respectively.

Figure 31
Summary of Average CT Energy Margins for All Simulated Cases



Notes:
Average CT energy margins in the Base Case and all change case scenarios.

Overall, comparison of these results shows that energy margins are heavily influenced by conditions experienced in neighboring regions, particularly when those neighbors are strongly interconnected. When the Study RTO is experiencing a severe shortage condition, it can partially alleviate the shortage and reduce energy prices by importing from neighboring systems. The price-moderating effect of such imports will be greater in more interconnected systems and neighboring systems with higher load diversity (so that scarcity does not happen simultaneously in all regions). However, the reverse can also be true. When the neighboring regions experience an extreme price spike, this will also attract imports from the Study RTO that will introduce scarcity-level prices in the Study RTO as well.

The overall impact of neighboring regions on Study RTO prices and energy margins therefore depends on the characteristics of the outside system, the level of load diversity among the systems, and the strength of interconnections. For example, because the systems we examine are quite similar and have significant load diversity, increasing interconnections will generally tend to moderate prices. In select circumstances however, expanded interconnections could also

increase price volatility in the Study RTO if a neighboring region has a greater potential for severe price spikes and shortage conditions. This would generally be the case for neighboring regions that are hydro-dominated with the potential for extreme shortages during low-water conditions that occur only once every five or ten years.[139]

B. CAPACITY MARKETS

Bilateral and centralized capacity markets were first implemented in the U.S. in the late 1990s as a means of achieving the prevailing 1-in-10 resource adequacy standards within restructured markets. Restructured markets rely on voluntary supplier investments to sustain resource adequacy, with incremental investments attracted only when suppliers can anticipate operating margins sufficiently high on average to cover the plants' fixed costs, recover investments, and earn a return equal to their cost of capital.[140]

The primary advantage of restructured markets that include a capacity market relative to energy-only markets is that the system operator is able to ensure that the administratively-determined planning reserve margins will be achieved. Depending on the policy objectives, these reserve margins may be set to achieve either: (a) the reliability objective such as 1-in-10, as is the case in the capacity markets of PJM, ISO-NE, and NYISO; or (b) an economic objective such as minimizing societal or customer costs, as in the proposed Italian capacity market.[141]

1. Capacity Payments Required to Achieve Reliability Targets

As discussed in Section IV.A above, energy-only markets by themselves will maintain some equilibrium level of investments, but will not necessarily achieve any particular administratively-determined reserve margin target. As explained in Section IV.A.4, the additional supplier returns required to achieve a particular target reserve margin is often referred to as "missing money".[142]

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[139] This type of situation is one that we have previously examined in Alberta that despite little hydro resource of its own is exposed to the risk of low-hydro conditions via its interconnection with BC Hydro. See Pfeifenberger and Spees (2011a), Section III.F.

[140] Note that even restructured markets do not rely entirely on merchant entry for all new supply. There are usually at least a small proportion of new assets within each footprint that are built on a regulated basis. An example is public power entities that build for self-supply. However, we classify a market as "restructured" if it will require at least some merchant entry to maintain resource adequacy in the region. This is the case, for example, in PJM where most new entry must come from merchant investors, although some new entry will be built on a regulated basis such as by Dominion, by a number of municipalities and cooperatives, or under the direction of state entities as in a selection of contracts in New Jersey and Maryland.

[141] We note that these markets actually express the resource adequacy standard as a "demand curve" for capacity that covers a range of reserve margins, although the range is developed around the underlying reliability or economic objective as discussed further in Section IV.B.4 below.

[142] For a discussion of investment shortfalls and the "missing money" problem in energy-only markets, see Cramton and Stoft (2006), Joskow (2008), and Pfeifenberger, *et al.* (2009). Note, however, that not all energy-only markets suffer from a missing money problem, and the problem can be addressed through means other than capacity markets. See, for example, Pfeifenberger and Spees (2013), documenting

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The missing money problem can be solved in deregulated markets by imposing resource adequacy standards on all LSEs. Such a resource adequacy standard requires LSEs to procure either sufficient generation or DR capacity to serve their own customers' coincident peak load plus the specified mandatory reserve margin. Such an LSE-based resource adequacy standard is imposed in all capacity markets that cover primarily deregulated regions, such as in NYISO, ISO-NE, and PJM. It is also used in California and regions with primarily (but not exclusively) regulated utilities such as MISO.[143]

Imposing a resource adequacy standard on LSEs automatically creates a bilateral market for capacity because it creates demand for installed capacity that is separate from the demand for energy and ancillary services. As a result, LSEs will have to pay for capacity to secure the needed obligations.[144] Within centralized capacity markets—as is the case in PJM, ISO-NE, and NYISO—the RTO procures the needed capacity resources on behalf of all customers and then assigns procurement costs to individual LSEs in proportion to peak load during the delivery period. However, regardless of whether the capacity market is centralized or bilateral, the existence of an enforceable resource adequacy standard means that the system operator will always be able to achieve the specified planning reserve margin.

The size of the capacity payments required to maintain the resource adequacy standard is a function of the target reserve margin as shown in Figure 32. Suppliers must anticipate being able to earn total operating margins equal to or greater than CONE before they will invest in the new resources. As explained in Section IV.A.1 above, energy margins exceed CONE at Study RTO reserve margins up to 7.9% (which corresponds to a 16.5% reserve margin in the combined four-system area, see Table 7 above). This means that only if the anticipated Study RTO reserve margin dropped below 7.9% would suppliers invest without the prospect of earning additional capacity payments. This also means that the capacity price would be zero if the Study RTO imposed a minimum reserve margin requirement at or below 7.9%.

For reserve margin requirements greater than 7.9% however, suppliers will not be willing to invest based on energy margins alone. At these higher reserve margins, suppliers must expect capacity payments equal to their Net CONE, which is the difference between their CONE and their anticipated energy margins. As shown in Figure 32 for our Base Case simulations, the equilibrium capacity price (red line) increases with the reserve margin requirement. This is because energy prices and suppliers' energy margins decrease causing Net CONE to increase.

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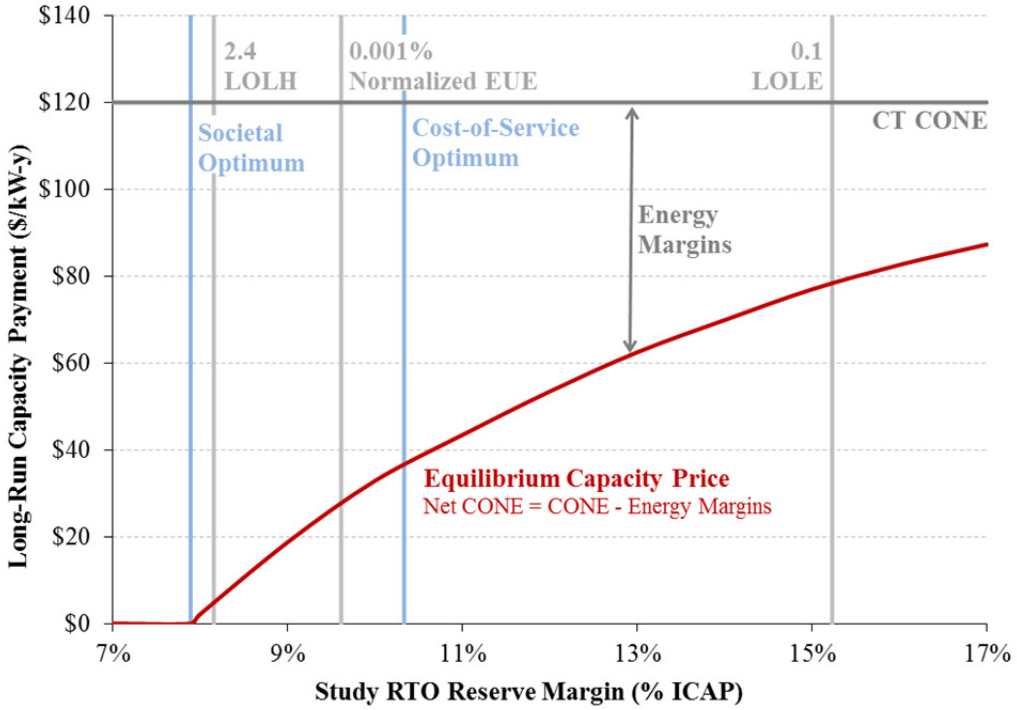
market prices that support sufficient investment in the Alberta energy-only market; and Newell *et al.* (2012) discussing a range of options, with and without a capacity market, to address a missing money problem in the Texas energy-only market.

143 For additional discussion of these capacity market designs as well as various alternative market designs for resource adequacy, see Spees, *et al.* (2013); and Pfeifenberger, *et al* (2009).

144 In regions with primarily cost-of-service regulated utilities, most of these capacity commitments are determined through integrated resource planning (IRP) and then secured through self-supply or long-term PPAs for bundled energy and capacity. However, there are often still at least some additional transactions for capacity as a distinct product. For example, see an analysis of California's short-term bilateral market for capacity in CPUC (2011), particularly in Section 4.3. See also Pfeifenberger, *et al.* (2012).

At the 15.2% reserve margin needed to maintain 0.1 LOLE, for example, an investor in a new CT would expect to earn approximately $40/kW-year in energy margins on average, while the total annualized investment and fixed cost (*i.e.*, CONE) is $120/kW-year. That supplier would not voluntarily invest unless capacity prices were expected to be at least $80/kW-year on average over the economic life of the plant.[145] By comparison, a capacity price of less than $30/kW-year would be needed to sustain the lower 10.3% reserve margin that is consistent with the risk-neutral cost-of-service optimum as discussed above.

Figure 32
Equilibrium Capacity Price vs. Reserve Margin Requirement



Notes:
Equilibrium capacity price equal to CT Net CONE of Base Case simulation.

2. Impact of Lower Energy Market Price Caps on the Capacity Market

Because capacity prices must be equal to Net CONE over the long-run to sustain a particular reserve margin, any factors that cause anticipated energy margins to drop will also cause capacity prices to increase if the reserve margin is to be maintained. Figure 33 illustrates this effect for our Study RTO, by showing the equilibrium capacity price level for simulation cases where the energy price cap is: (a) set at the VOLL of $7,500/MWh as in the Base Case; (b) reduced to $3,000/MWh; and (c) reduced to $1,000/MWh.

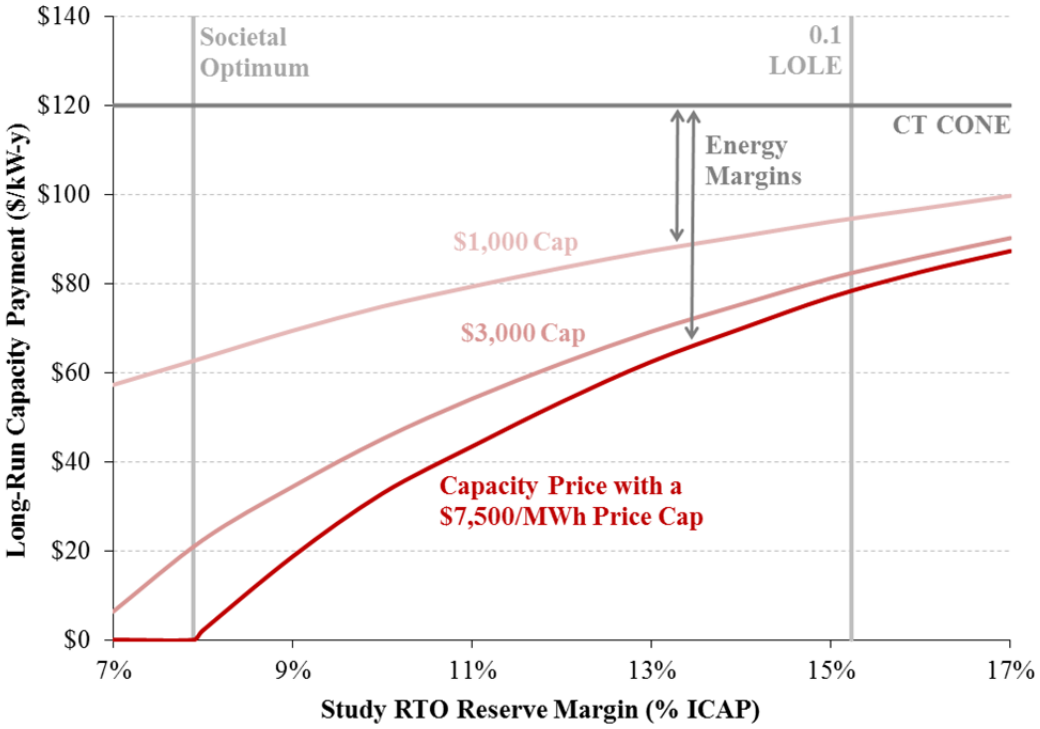
As explained in Section IV.A.4 above, reducing the price cap below VOLL or otherwise suppressing energy prices below marginal system costs will result in under-investment in an energy-only market design. This is not the case in regions with reserve margin requirements,

[145] In other words, Net CONE ($80/kW-year) = CONE ($120/kW-year) – Energy Margins ($40/kW-year).

because any reduction in energy margins will be offset by an increase in supplier compensation through increases in capacity prices. As Figure 33 shows, at any level of reserve margin, lowering the cap on energy prices significantly increases capacity prices. The impact of price caps is greater at lower reserve margins because scarcity conditions and associated price spikes are encountered more frequently at the lower margins.

This interaction between energy margins and capacity market prices also means that regions with resource adequacy requirements and associated (bilateral or centralized) capacity markets will be able to achieve their reliability targets even if energy prices are artificially suppressed. This does not mean, however, that capped or otherwise suppressed energy prices have no consequences on market efficiency. Rather, overall market efficiency will be lower because the capped or otherwise lower energy prices will lead to inefficient investment decisions, inefficient hedging and forward contracting incentives, inefficient demand response, inefficient real-time performance incentives, and inefficient dispatch of resources.

Figure 33
Equilibrium Capacity Prices with Different Energy Market Price Caps



Notes:
Equilibrium capacity price is at CT Net CONE.
Calculated at price caps of $7,500/MWh (Base Case), $3,000/MWh, and $1,000/MWh.

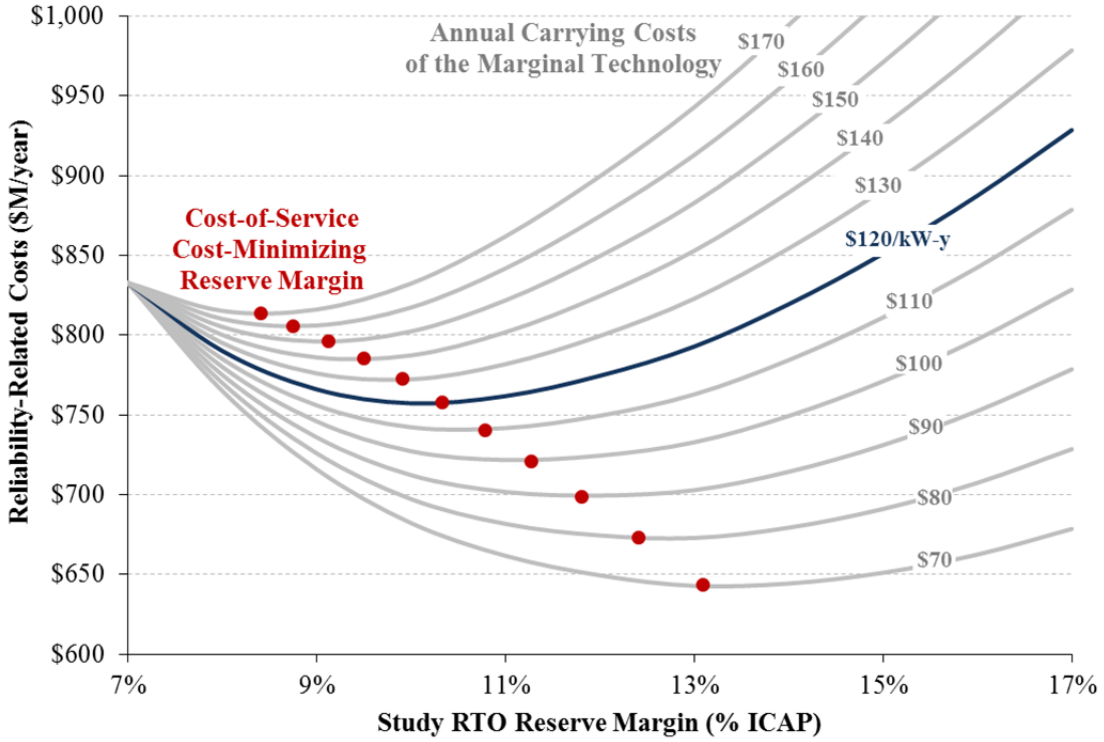
3. Cost-Minimizing Capacity Demand Curves

The optimal, cost-minimizing reserve margin also depends on the levelized fixed costs of adding more capacity resources to the system. In estimating the cost-minimizing reserve margin in Sections III.A.2 and III.A.3 above, we assume levelized fixed costs equal to a CT CONE of $120/kW-year. In reality there is some uncertainty in CONE from an administrative perspective,

due to variability in construction costs, financing costs, and even technology specifications among potential investors.

Figure 34 shows how total reliability-related costs change with varying CONE levels and reserve margins, and highlights the minimum average cost point with a red dot in each case. The figure shows total reliability-related costs as calculated in Section III.A.2 from a risk-neutral, cost-of-service perspective. The figure also shows that changes in the assumed level of CONE shift the economically-optimal reserve margin by several percentage points. Varying CONE between $70/kW-year to $170/kW-year corresponds to cost-minimizing reserve margins that range from 8.4% to 13.1%.

Figure 34
Cost-Minimizing Reserve Margin with Varying CT CONE
(Risk-Neutral, Cost of Service Perspective)

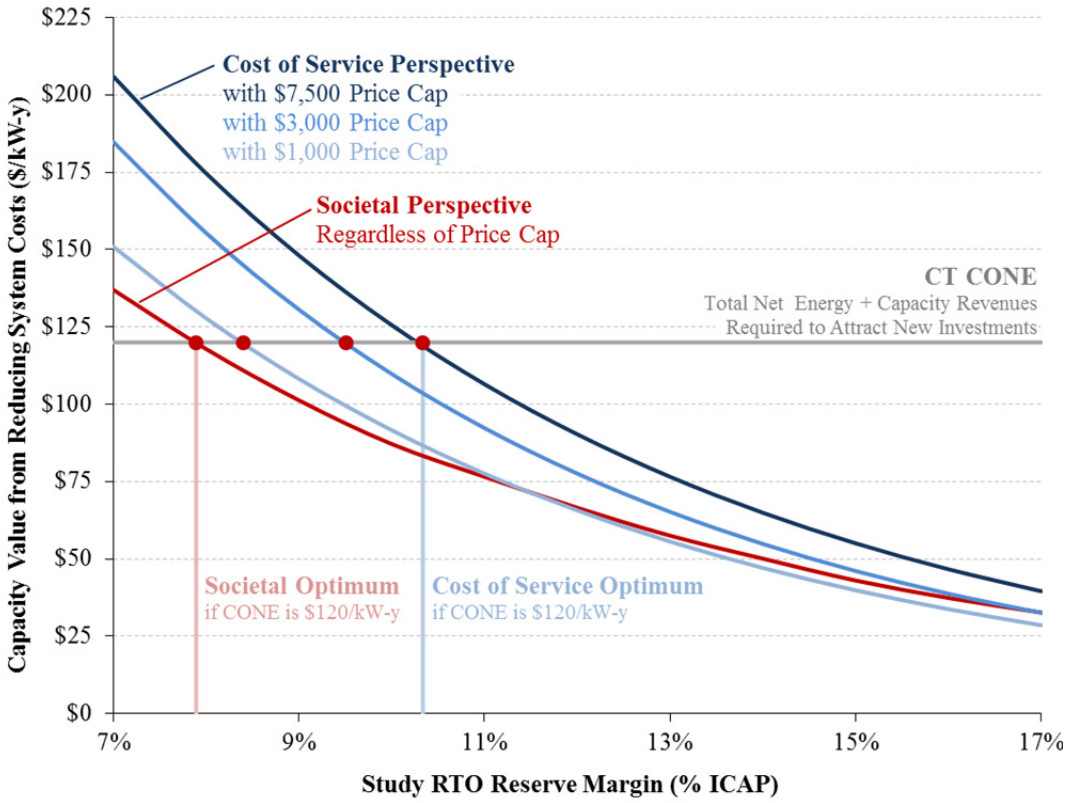


Notes:
Base Case reliability-related costs from a risk-neutral, cost-of-service perspective, see Section III.A.2.

The fact that the economically-optimal reserve margin depends on CONE suggests that administratively-determined reserve margin requirements should also vary with CONE. In other words, it would be more efficient to maintain a higher reserve margin if additional capacity can be added at relatively low cost. Similarly, mandated reserve margins should be lower if new capacity is expensive. This economically-efficient approach to procuring capacity could be achieved in either cost-of-service regulated power markets or deregulated regions within a capacity market. It would require: (a) estimating the incremental value of capacity using probabilistic economic and reliability simulations (as we have done for the hypothetical Study RTO); and (b) comparing that value against the total cost of procuring capacity, which may be unknown in advance.

Figure 35 shows the value of incremental capacity as a function of reserve margins. We calculate the incremental capacity value as the reduction in total system costs (excluding capital costs) that would be achieved by adding incremental capacity. As the figure shows, this incremental value of capacity also depends on whether one applies a cost-of-service or societal perspective for calculating total system costs. We thus show capacity values for: (a) a risk-neutral, cost-of-service perspective in a system with a price cap at the $7,500/MWh VOLL, as well as at the lower price caps of $3,000/MWh and $1,000/MWh; and (b) a risk-neutral societal perspective. The value of capacity is a function of price caps only under a cost-of-service perspective, because the lower price caps (which are applied in both Study RTO and neighboring regions) will reduce the cost of procuring emergency imports. From a societal perspective, however, the value of capacity does not depend on energy prices. It depends only on internal and external production and reliability-related costs, not on the market prices themselves.

Figure 35
Reduction in Expected System Costs Achieved by Adding Capacity
(Excluding the Carrying Costs Required to Build the Incremental Capacity)



Notes:

Capacity value is the reduction in system costs (excluding capital costs) achieved per unit of capacity added.

Cost-of-Service costs are calculated for the Base Case as well as the $3,000/MWh and $1,000/MWh price cap cases from a risk-neutral cost-of-service perspective as in Section III.A above. Societal costs are calculated for the Base Case on a risk-neutral basis as in Section III.A.3 and do not vary with price cap levels.

Plotted with x-axis based on the Study RTO internal reserve margin. Note that the 7.9% "socially optimum" reserve margin in the Study RTO is equivalent to a 16.5% reserve margin across all systems' coincident peak loads, as explained in Table 7 in Section III.A.3.

Any time the incremental value of capacity (shown as downward-sloping lines), exceeds the incremental cost of new capacity, it would be efficient to procure more capacity. This comparison must consider the *total* procurement costs, including both capacity payments and net energy payments.[146] Figure 35 compares these value-of-capacity curves for our Study RTO to the Base Case CONE value of $120/kW-year. The value of capacity is equal to CONE at the risk-neutral, economically-optimal reserve margin as calculated previously and indicated with red dots in the chart. These optimum reserve margins would increase if CONE were lower, as discussed above.

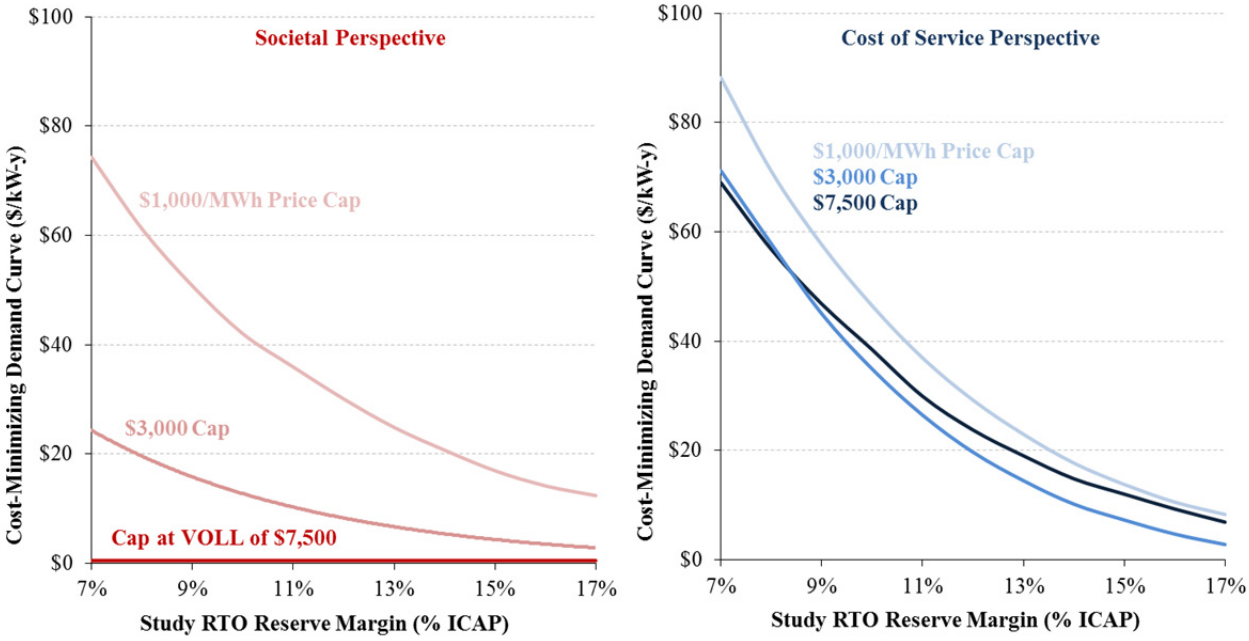
Within a capacity market, one can translate this value-of-capacity calculation into a cost-minimizing demand curve for capacity by subtracting out the portion of total costs that suppliers would be able to cover through energy margins as shown in Figure 36. This demand curve for capacity would procure the quantity of capacity needed to minimize total system production, reliability, and capital costs, as calculated on a risk-neutral basis. These demand curves would need to be shifted to the right if policy makers or RTOs wished to incorporate some risk aversion into their procurement levels as discussed in Section III.A.4 above. Note, however, that the risk mitigation preferences of suppliers and customers might alternately be resolved through market-based hedging and forward contracting, at least in efficient and competitive markets with liquid futures markets and forward contracting opportunities.

The cost-minimizing demand curve from a societal perspective (left chart) is zero at all reserve margins in our Base Case where the price cap is set at VOLL. This is because, under the special circumstances of having perfectly efficient energy market prices, the energy-only market will be sufficient to attract the efficient quantity of capacity investments from a societal perspective as explained in Section IV.A.2. However, if the price cap is below VOLL or energy prices are otherwise suppressed, it would be efficient to procure additional capacity through a capacity market. The lower the price cap and the greater the price suppression, the higher the capacity demand curve would need to be to procure the socially-optimal quantity.

From a risk-neutral cost-of-service perspective (right chart), the cost-minimizing demand curve is also a downward-sloping function with a very similar shape. As the chart shows, however, the height of the demand curve is not as directly related to the price cap as is the case for the socially-optimal demand curves. This is because the value of capacity is partly tied to the suppression of energy prices and associated reduction of net import costs. With a lower price cap, the value of higher reserve margins on reducing import costs is less (lowering the demand curve) but the effect is offset because suppliers' energy margins would also be reduced (increasing the demand curve). These offsetting factors result in a demand curve that is not as heavily impacted by the price cap.

[146] In the context of a region with a capacity market, the total payments would be the sum of energy margins and capacity payments based on the market prices for energy and capacity. In a regulated utility setting with PPAs, the total procurement cost would be net energy payments plus capacity payments under the PPA, which may be broken down in various ways depending on contract terms.

Figure 36
Risk-Neutral, Cost-Minimizing Demand Curve for Capacity



Notes:
Calculated as the value of capacity from Figure 35 minus the energy margins from Figure 26.

4. Current RTO Demand Curves Compared to Cost-Minimizing Curves

Figure 37 compares the cost-minimizing demand curves calculated in the previous section to demand curves that are currently being used in the capacity markets in NYISO, ISO-NE, PJM, and MISO. We compare the demand curves that would be calculated under the Base and 50% Transmission Cases from the risk-neutral societal perspective under a $1,000/MWh price cap. We selected these cases to compare because we believe that these two simulation cases may most closely resemble these various real-world RTOs, but stress that the value-based demand curve would be quite different if estimated for any particular region.

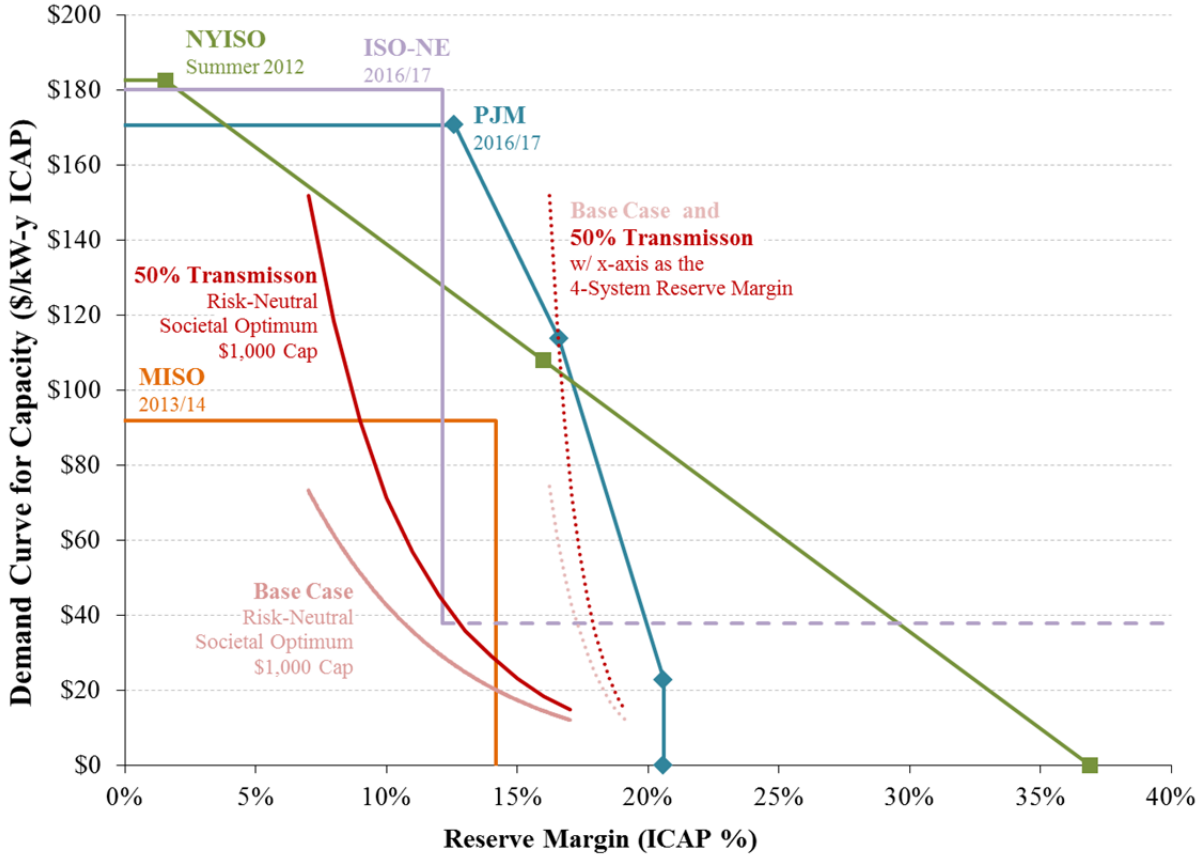
We plot the curves in two different ways: (1) with the x-axis defined as the Study RTO's reserve margin compared against the Study-RTO non-coincident peak load (solid lines); and (2) with the x-axis defined as the combined four-system reserve margin against the combined systems' coincident peak load (dotted lines). Further, we note that these risk-neutral demand curves would have to be shifted to the right if policy makers or RTOs wished to incorporate risk mitigation benefits into the demand curves.

Not surprisingly, the cost-minimizing demand curves from a risk-neutral societal perspective have lower prices than the actual RTO demand curves when compared against the Study RTO reserve margin. This is primarily because these actual RTO demand curves were developed with the objective of achieving the 0.1 LOLE standard, while a risk-neutral societal approach would aim to procure a lower reserve margin and reliability level under our study assumptions. Actual RTO demand curves also reflect a number of other objectives and real-world considerations such as: (a) the objective of mitigating capacity price volatility; (b) the practical difficulties of administratively estimating demand curve parameters, including the approximate Net CONE at

the target reserve margin; and (c) the difficulty of building consensus on a capacity demand curve's shape, given the multitude of stakeholders with disparate and competing interests that are involved in such market development efforts.

While U.S. RTOs with capacity markets and their regulators have not yet demonstrated substantial interest in considering such a value-based approach to estimating demand curves (whether risk-neutral, or risk-adjusted), we note that Italy will soon implement a capacity market with a value-based demand curve that is at least conceptually similar to the approach that we have outlined in the previous section.[147]

Figure 37
Cost-Minimizing Capacity Demand Curve vs. Current RTO Demand Curves



Sources and Notes:

All curves converted from source units into ICAP terms for both reserve margin and price.

Cost-minimizing demand curves plotted with x-axis as: (1) the Study RTO reserve margin against Study-RTO non-coincident peak load (solid lines); and (2) against the combined four-system reserve margin against the combined coincident peak load (dotted lines). See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting convention.

See ISO-NE (2013); MISO (2012c, 2012d); NYISO (2013); PJM (2013a).

[147] Italy's system operator Terna has submitted its proposal for calculating this value-based demand curve, as briefly outlined in Terna (2012), Sections 2.3-2.4.

C. IMPLICATIONS OF INCREASED DEMAND RESPONSE PENETRATION

Section IV.C examines the system cost and reliability implications of increasing levels of demand response penetration, assuming that increasing DR resources would displace traditional generation. Increasing DR penetration also has a number of important implications for energy and capacity market outcomes. Namely, as DR penetration increases and displaces generation resources, it will: (1) cause the energy supply curve to shift upward because lower-dispatch-cost CTs are being replaced by DR with higher dispatch cost, resulting in higher energy prices during peak load and scarcity conditions; (2) increase average generator margins due to the higher peak energy prices; and (3) reduce capacity market prices by increasing generators' energy margins. We discuss these and related implications for market design in the following sections, and evaluate the relevance of these results to PJM's market, which is the U.S. market that will be relying most heavily on DR resources over the coming years.

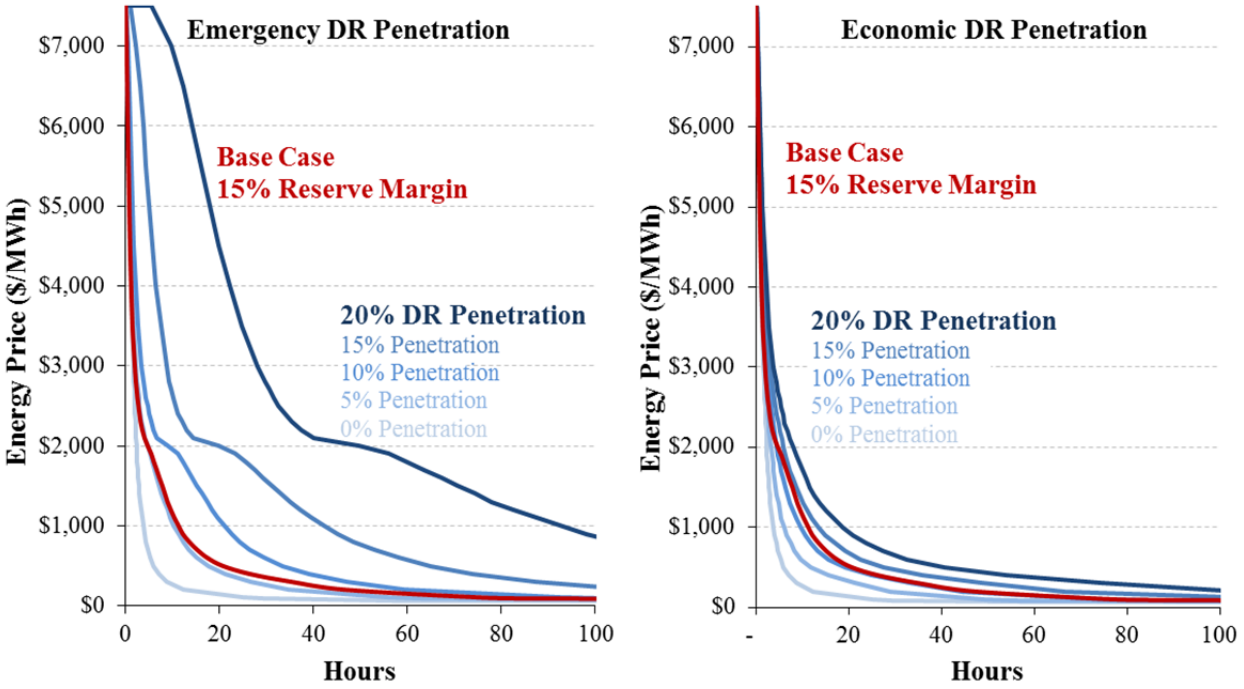
1. Energy Market Impacts

As DR penetration increases, it will displace traditional generation resources if the reserve margin requirement remains fixed. This will increase the supply curve and realized prices in the energy market, because lower-dispatch-cost generation resources will be displaced by higher-dispatch-cost DR. If that DR is primarily "emergency" rather than "economic" DR it will have an even greater impact on the energy market because: (1) emergency DR is available only during emergency conditions (at a high strike price of $2,000/MWh assumed in our simulations), while economic DR is available over a wide range of dispatch prices, including a portion that is available at relatively low dispatch prices (a few hundred dollars in our simulations); and (2) emergency DR is a dispatch-limited resource (in our simulations it can only be dispatched up to 100 hours per year), resulting in even higher energy prices during any years when the dispatch limit is exceeded.

Figure 38 illustrates these impacts by showing the price duration curve for the Base Case simulations and a 15% planning reserve margin and varying market penetration levels for emergency DR (left chart) and economic DR (right chart). For comparison, we also show the price duration curve from the Base Case simulations at the same 15% reserve margin.[148] The distinction between emergency and economic DR is not particularly important at relatively low penetration levels of up to 5% (similar to historical experience), because the frequency with which the DR resource will be dispatched is quite low at these penetration levels. As explained in Section III.C.1 above, at the 5% penetration level, one would expect few or no DR calls in years with typical weather. However, with higher levels of DR penetration (darker blue lines), the entire price duration curve is shifted up, with the increase being substantially larger if the DR resources consist only of dispatch-limited emergency DR rather than economic DR.

[148] Recall that the Base Case simulation has a 6.9% DR penetration level, with DR resources consisting of 80% emergency DR and 20% economic DR.

Figure 38
Energy Price Duration Curve with Increasing DR Penetration
(Average Year Results at Fixed 15% Reserve Margin)



Notes:
The average price duration curve at 15% reserve margin and varying levels of Emergency (left) or Economic (right) DR penetration.

In our simulations, the high reliance on Emergency DR also has the effect of creating a "shelf" in the price duration curve at the assumed emergency DR strike price of $2,000/MWh.[149] The shelf in energy market prices is an artifact of the high-dispatch-cost nature of Emergency DR. Emergency DR implicitly assumes that all DR resources are identical and that the underlying DR resources all have the same strike price. In reality, however, every individual DR asset will have its own strike price that could be above or below the $2,000/MWh assumed in our simulations. Indiscriminately dispatching Emergency DR assets as if they had a uniform strike price will have the problematic effect of calling on DR resources with high strike prices of several thousand dollars, when lower-cost economic DR and non-DR resources would likely be available. Additionally, DR resources with a strike price of only a few hundred dollars would prefer to be interrupted much more frequently by customers trying to avoid high energy prices.

The Economic DR penetration simulation cases demonstrate generally preferable outcomes. Integrating high-levels of Economic DR results in a smoother, better-behaved price duration curve with no artificial "shelf" caused by an administratively-determined Emergency DR strike price level. This illustrates the efficiency gains from integrating economic DR resources into wholesale markets, whether they are directly dispatchable by the system operator or only

[149] Note that the shelf is somewhat smoothed by the fact that the plots show the average price duration curve over many simulation runs. In any individual run or delivery year the shelf would be an even more prominently "blocky" feature of the emergency DR curve.

responding to market prices. The market is more efficient overall because each DR resource has self-selected its own level and price of curtailments. For example, end users place relatively little value on service for at least a portion of their total load may respond to energy market prices and curtail demand at a relatively low strike price of $500/MWh. In our simulations, this DR resource would be curtailed approximately 40 times per year (or less than one hour per week) in the 20% penetration case, an interruption frequency that many end users may find acceptable for non-essential uses.[150]

To date, the consequences of relying heavily on Emergency DR have not yet been a major concern because Emergency DR is rarely, if ever, dispatched in most systems. This is because: (a) many U.S. systems have had modest DR penetration levels of only 6% to 7%; (b) many U.S. RTOs have an surplus generation capacity, which means Emergency DR would rarely be called even if the system had a high DR penetration level; and (c) energy prices are capped and rarely exceed a few hundred dollars in most systems, meaning that only DR resources with the very lowest strike prices have had any reason to participate in the energy market.

This will change over the next years however, particularly in PJM, where high levels of DR have displaced generation for the next several delivery years. This will cause a substantial increase in DR dispatch over the coming years.[151] Historically, and consistent with our Base Case assumptions, 80% of PJM's DR assets have participated as emergency-type DR, while only 20% participated in the energy market. It seems very likely that, as energy prices and DR dispatch hours increase over the coming years, more DR will begin participating in the energy market because there will be increasingly more hours during which the "true" strike price of lower-cost DR resources will be exceeded.[152] Resources with very high strike prices will not opt to participate directly in PJM's energy market, however, because: (a) their strike prices may exceed the energy price cap, in which case they would never wish to be interrupted; or (b) their number of call hours is too low, so that the benefits of participating in the energy market would not justify the infrastructure or overhead costs of direct market participation.

2. Impact on Generator Energy Margins

Consistent with the increase in energy prices caused by displacing generation with DR resources, generator energy margins would increase as shown in Figure 39. The figure shows the average annual energy margins (red) as a function of DR penetration, along with the annual margins expected in the median year (blue), middle 50% of years (dark gray), and middle 90% of years

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150 However, even very high interruption rates may be tolerable if managed within a portfolio of resources by a DR aggregator, because an aggregator could limit the interruption rate of any individual DR asset by maintaining a high quantity of DR assets that exceeds its curtailment obligation under any one event.

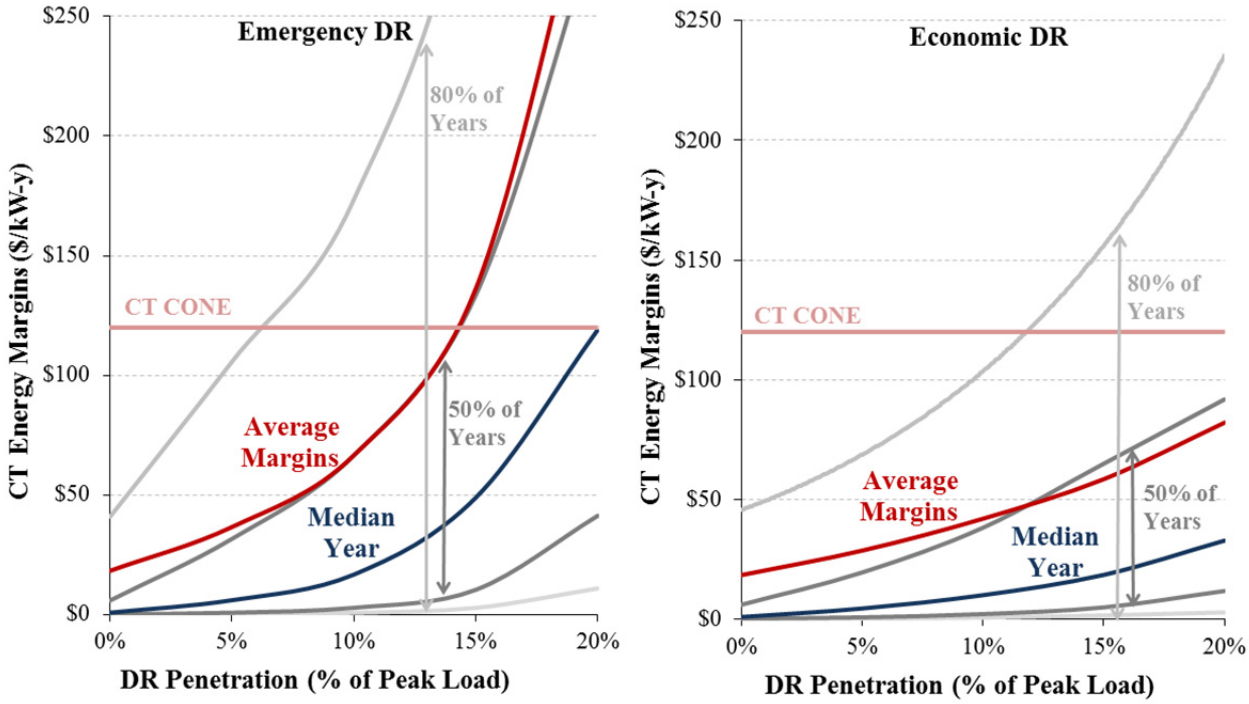
151 For an analysis of how DR displacing generation may increase DR call hours in PJM over the coming years, see Newell and Spees (2013).

152 DR may participate directly by offering hourly bids into the energy market or, possibly more commonly for resources that wish to avoid the substantial effort required to submit hourly energy bids into the nodal market, these assets may submit a single energy strike price that is applicable all year and that would be used with slightly less locational dispatch precision. For an overview of PJM's new scarcity pricing mechanism, including its approach to incorporating emergency and economic DR into price-setting, see PJM (2012b).

(light gray). Consistent with the observations about energy price impacts, relying more heavily on Emergency DR will increase generator energy margins more quickly than relying more heavily on Economic DR. Again, this is because Economic DR will offer into the energy market at a large range of prices, including at some relatively low prices of only a few hundred dollars.

The smoother and better-behaved price formation associated with Economic DR also translates into substantially less volatility in year-to-year spot energy margins earned by suppliers. With Emergency DR, the 100 hour call limit and energy price "shelf" at the assumed administratively-set level of $2,000/MWh result in a much larger difference in energy margins between moderate years (with few or no DR calls) and extreme years (with many DR calls all at the same high price). At the 15% Emergency DR penetration level, our simulations result in spot-market-based energy margins of $48/kW-year (41% of CONE) for the typical year but up to $334/kW-year (2.8 times CONE) once per decade. In comparison, CTs would experience lower (but much less volatile) energy margins in a market with 15% Economic DR penetration. For that case, our simulations yield spot energy margins of $18/kW-year (15% of CONE) for the typical year and as high as $152/kW-year (1.3 times CONE) once per decade.

Figure 39
Volatility in Energy Margins vs. Emergency DR (left) or Economic DR (right) Penetration
(Fixed 15% Reserve Margin)



Notes:
CT energy margins in the Study RTO when displacing CTs with increasing levels of DR penetration.
Gray lines represent the 10th, 25th, 50th, 75th, and 90th percentile estimates of energy margins.

3. Impact on Capacity Market

The increase in energy margins with higher DR penetration will also have the long-run effect of decreasing equilibrium capacity prices, because total generator net energy and capacity revenues will have to equal CONE on average as explained in Section IV.B.1 above. This consequence is demonstrated in Figure 40 that shows the equilibrium capacity price at a 15% reserve margin with increasing Emergency DR penetration, increasing Economic DR penetration, and under our Base Case simulation.

Capacity prices are the same with Emergency and Economic DR at the 0% penetration level, and decrease more quickly in the Emergency DR Case because energy market prices increase more quickly.[153] In fact, at approximately 14% Emergency DR penetration, the capacity market price would be driven all the way to zero, with energy prices so high that traditional generators would be willing to build even if they had no capacity payments. Obviously, this outcome is economically infeasible because Emergency DR providers would need a capacity payment that is at least high enough to pay for their fixed annual costs and expected net interruption costs.[154] In other words, if only Emergency DR existed, then the capacity market would converge to an equilibrium DR penetration level somewhere below 14%.[155]

If only Economic DR existed and at the quantities that we assume can actually be realized, then capacity prices would drop with increasing penetration levels but would not drop to zero over the penetration levels we examine. In that case, DR penetration would level off at the fixed costs of maintaining DR minus the net value of participating in the energy market.[156] We do not attempt to quantify that equilibrium penetration level for our purposes, but note that the fixed costs of adding more DR will necessarily increase at higher penetration levels as the lowest-cost DR

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[153] Note that in a real-world capacity market the difference between the Emergency and Economic DR Cases might be somewhat smaller because the RTO is likely to reduce the capacity credit awarded to Emergency DR at high penetration levels as it becomes obvious that the call-limited Emergency DR is providing substantially lower reliability value. This would mean that the Emergency DR would displace somewhat less generation capacity than the Economic DR, which would somewhat reduce the impacts on energy market prices, CT energy margins, and capacity margins.

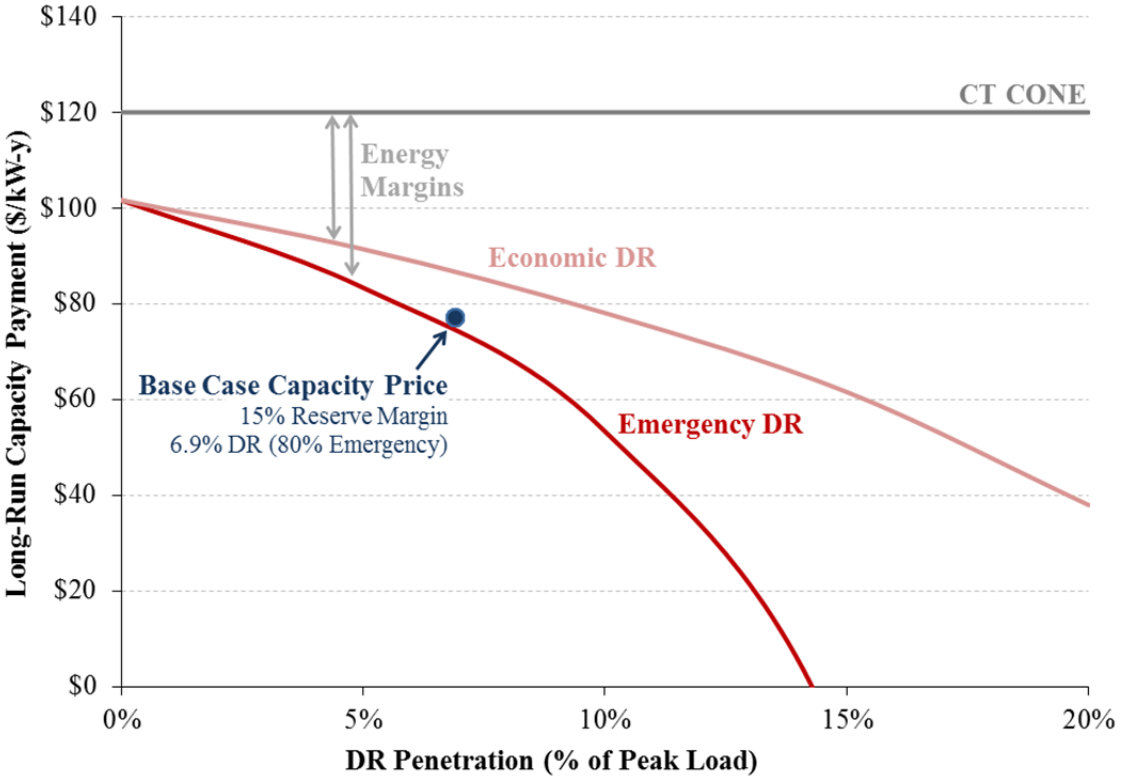
[154] Note that DR suppliers have an annual "net interruption cost" that would be calculated very similarly to generator energy margins but can actually be positive or negative in total value. The value of the "net interruption cost" is the energy price when called minus the true strike price. If the energy price when called exceeds the DR asset's true strike price then the interruption provides positive value to the DR supplier, who avoids paying energy prices in excess of their private value (note that for Economic DR the energy price always exceeds the true strike price when called and so participating in the energy market would always create positive value). In the alternate case when the energy price is below the DR asset's true strike price, the interruption will impose a net cost on the DR supplier. For example, if a DR asset's true strike price is $5,000/MWh, but the energy market price cap is $1,000/MWh (or the administratively-determined Emergency DR strike price is $2,000/MWh), then every interruption would impose a net cost.

[155] Penetration levels of Emergency DR would also be limited by the fact that call-limited DR has lower capacity value and would probably therefore be assigned lower capacity payments at these high penetration levels. PJM has already implemented such a mechanism for differentiating capacity payments among call-limited and unlimited DR products. For an explanation and discussion of PJM's multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

[156] See footnote 154 for an explanation of the net value that a DR asset would earn in the energy market.

resources are already committed and only higher-cost DR options remain available for incremental procurement.

Figure 40
Equilibrium Capacity Prices with Increasing Levels of DR Penetration
(Fixed 15% Reserve Margin)



Notes:
Equilibrium capacity price is at CT Net CONE.

In real markets, most DR is currently Emergency DR, suggesting capacity and energy market impacts more similar to the Emergency DR case at low penetration levels. For example, in PJM approximately 80% is Emergency DR while approximately 20% is Economic.[157] However, as total DR penetration levels increase, we believe it is likely that a greater proportion of DR will begin to participate in the energy market, driven by increasing energy prices as explained in Section IV.C.1. However, some Emergency DR will never migrate into the energy market because energy market prices would so infrequently exceed their true strike price (or may never exceed their true strike price if the energy market cap is far below VOLL).[158] In other words, it is still plausible that even with a price cap that is somewhat below the likely VOLL, the

[157] See PJM (2013c), p. 5.

[158] Emergency DR would only migrate into the energy market if the net value of participating in the energy market exceeds the increase in fixed infrastructure and administrative costs incurred.

combination of PJM's energy and capacity markets may be able to attract a relatively efficient portfolio of Economic and Emergency DR.[159]

D. COMPARISON OF CAPACITY AND ENERGY-ONLY MARKET DESIGNS

This section of our report provides a high-level comparison of realized energy and capacity prices, supplier net revenues, and customer costs under alternative energy-only and capacity market designs. We also compare simulation results with varying price caps and target reserve margin levels. These results reflect realized prices and costs under a restructured energy-only or capacity market in which suppliers earn market-based revenues to recovery their fixed costs and customers pay market prices for energy and capacity.

1. Supplier Net Revenues

Figure 41 shows supplier net revenues (*i.e.*, total market-based revenues less operating costs) for a new CT from energy margins and capacity payments under the Base Case simulation over a range of reserve margins.[160] As explained previously, in a restructured wholesale energy-only or capacity market, supplier net revenues must be equal to the fixed costs at CONE to sustain the investment needed for a particular equilibrium reserve margin. Under our simulations, we estimate 7.9% equilibrium reserve margin for the energy-only market design. At this equilibrium reserve margin, suppliers would earn net revenues that fully recover their investment and earn sufficient returns in the energy market. Policy makers would have the option to require a higher planning reserve margin, but doing so would necessitate a resource adequacy requirement that creates additional compensation through bilateral or centralized capacity markets. In the following discussion we focus on energy-only and centralized capacity market designs.[161]

As planning reserve margin requirements increase, energy margins will decrease. This means that the proportion of supplier net revenues from capacity payments—needed to avoid under-investment due to "missing money"—will increase at higher reserve margins. Capacity payments will, for example, need to cover more than 70% of CONE at the 17% reserve margin. For intermediate and baseload units, capacity revenues would be the same but represent a lower fraction of net revenues because those resource types would earn higher energy margins and have higher fixed costs.

In other words, in equilibrium, supplier net revenues are the same in energy-only and capacity market designs and cover the long-run marginal cost of supply. However, the proportion of net

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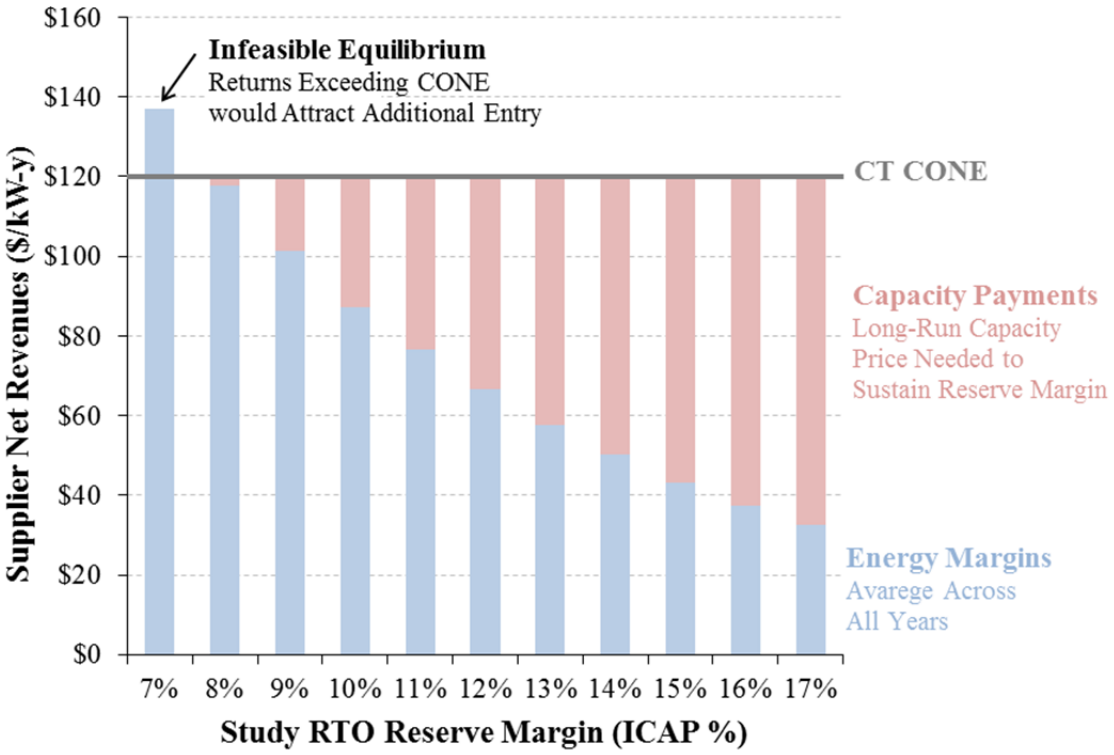
[159] With the primary inefficiency stemming from the lack of an efficient call order among resources whose strike price is near to or exceeds the energy market cap. PJM's current cap on the energy component of the LMP is $1,500/MWh,as of October 2012 and will rise to $2,700/MWh by June 2015, see PJM (2012b), p. 162.

[160] Average energy margins and capacity prices are calculated as explained in Sections IV.A.1and IV.B.1 above respectively.

[161] While other approaches to achieving higher planning reserve margins exist, we focus here only on energy-only and capacity market approaches for simplicity. For a broader discussion of alternative approaches, see Pfeifenberger, *et al.* (2009); and Spees, *et al.* (2013).

revenues from the energy and capacity markets is quite dependent on market design, reserve margin requirement, and other fundamentals that affect energy market prices. The proportion of supplier returns from the energy and capacity markets can also have substantial implications if one or the other of these markets is particularly exposed to regulatory risks or inefficiencies as discussed above. Further, any inefficiency in the capacity or energy only market designs could result in attracting or maintaining an inefficient mix of baseload, intermediate, and peaking resources.

Figure 41
Supplier Net Revenues as a Function of Planning Reserve Margin Requirements



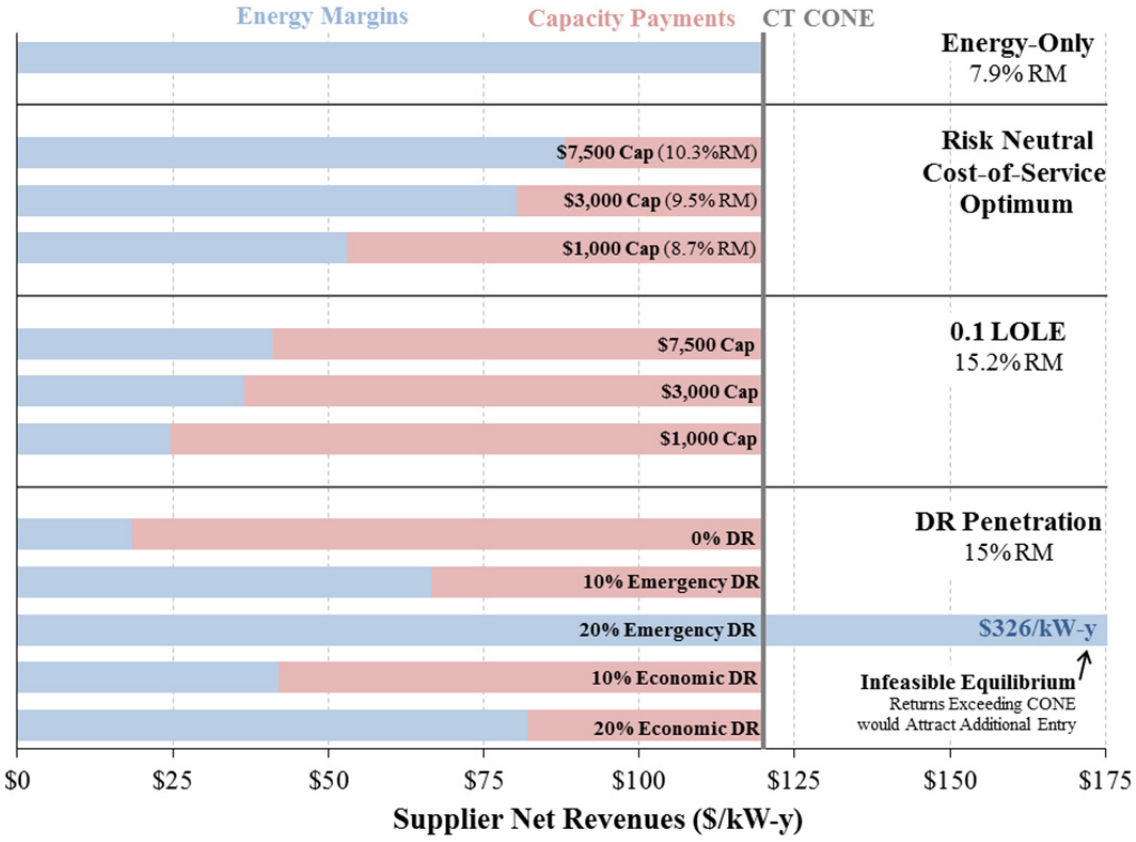
Notes:
Study RTO Base Case results, see Sections IV.A.1and IV.B.1 for calculation details.

Figure 42 similarly shows supplier net revenues from energy and capacity markets under different market designs, price caps, reserve margin targets, and DR penetration levels. Again, note that, to be able to attract investment, supplier net revenues are always equal to CONE in equilibrium, although the proportion from capacity versus energy margins varies with design.[162] The figure shows that a capacity market with a planning reserve margin requirement set at the risk-neutral, cost-of-service optimum would require that suppliers earn 27% to 56% of their net revenues from the capacity market (depending on the price cap), while the capacity market with a reserve margin requirement based on the 0.1 LOLE standard would require that 66% to 80% of

[162] Also note that the case with energy margins exceeding CONE indicates a disequilibrium that would attract more supply until reserve margins increased enough to decrease supplier net revenues until they equal CONE.

net revenues are earned in the capacity market. With higher levels of DR penetration, generation suppliers would earn a greater portion of their net revenues in the energy market.

Figure 42
Supplier Net Revenues Under Different Market Designs and System Conditions



Notes:
Study RTO results for Base, Price Cap, and DR Penetration Cases.

2. Total Customer Costs

Figure 43 shows the annual average of total customer costs as a function of planning reserve margin in the Base Case simulation, including transmission and distribution, energy, and capacity costs.[163] Note that T&D costs do not change with the reserve margin, while energy costs decrease and capacity costs increase, consistent with the trends in market prices discussed above. The directional change in the proportion of customer costs incurred for energy and capacity are similar to the directional changes in supplier returns for the marginal CT, but the magnitudes are different because: (a) customer costs reflect total energy costs not just the above-cost portion represented by energy margins; and (b) customer costs reflect total energy and capacity payments to all types of resources other than just the marginal CT including

[163] T&D costs are based on a national average, from EIA (2013b).

intermediate and baseload resources whose total returns are more focused on energy than capacity.[164]

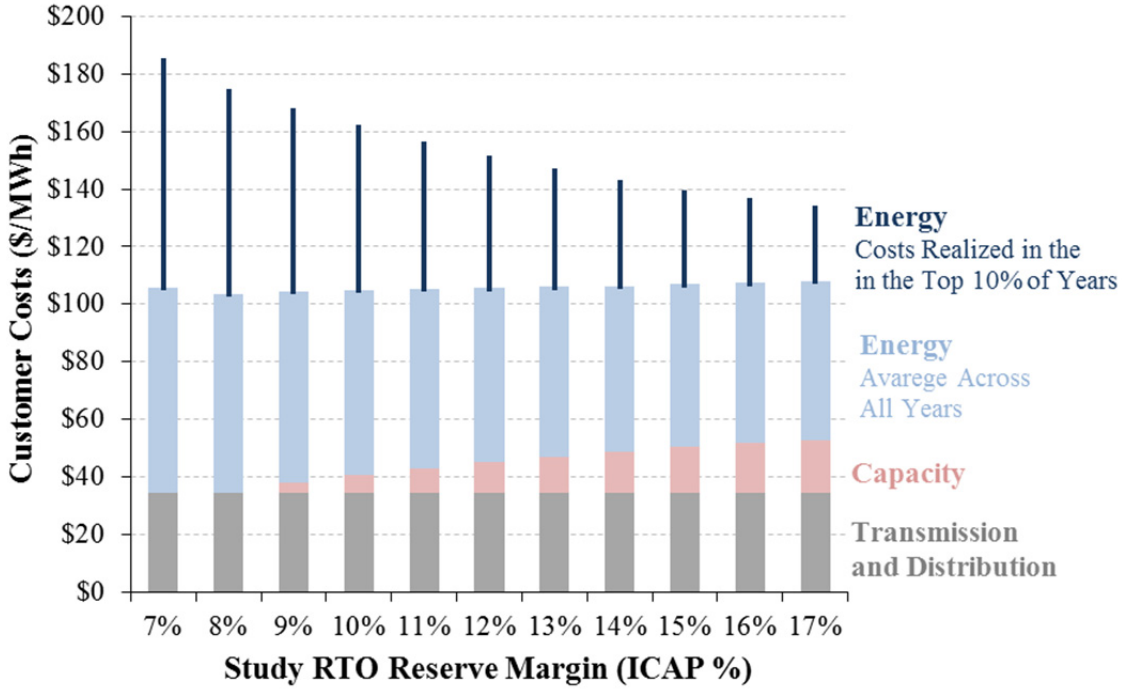
Total customer costs are minimized at the risk-neutral, "societally-optimal" reserve margin of 7.9%, consistent with the discussion in Section IV.A.2 above. Unlike individual suppliers' equilibrium net revenues, customer costs vary with the reserve margin even in equilibrium conditions. This is because the total system cost increases with planning reserve margins and the total generation base that must earn sufficient net revenues increases. However, the increase in total customer costs with reserve margin is quite small as a percent of total costs, making the increase difficult to see when total costs are shown to scale. In fact, increasing the reserve margin above the risk-neutral, societal optimum of 7.9% to the 15.2% reserve margin needed under the 0.1 LOLE standard increases average customer costs by $1.63/MWh or only 1.5%.

Importantly, we note that the incremental customer cost imposed by implementing a capacity market relative to an energy-only market cannot be calculated simply by estimating the final capacity price and multiplying by the procured quantity. This is because increasing the reserve margin with a capacity market not only introduces capacity costs but also reduces energy-related costs, a factor which is not considered in many discussions.

Figure 43 is also useful for answering the deceptively simple question of whether energy-only or capacity markets are more expensive for customers. The real answer is that total customer costs have less to do with energy-only versus capacity market design, but more to do with the equilibrium reserve margin. Whether through energy-only or capacity market design, total capacity costs must be sufficient to cover the capital and operating costs of the fleet in expectation. The exact reserve margin achieved depends on market design details, with: (a) the capacity market reserve margin determined by the planning reserve margin target, and (b) the energy-only market reserve margin determined by the level of market prices (which may be higher or lower than the "optimum" depending on whether energy prices are more often above or below the perfectly efficient level).

[164] However, in a true, perfect equilibrium, the Net CONE of all resource types would be equal even though energy margins will be different. See Section IV.A.2 for additional discussion.

Figure 43
Total Customer Costs and Spot Market Exposure for Different Planning Reserve Margins



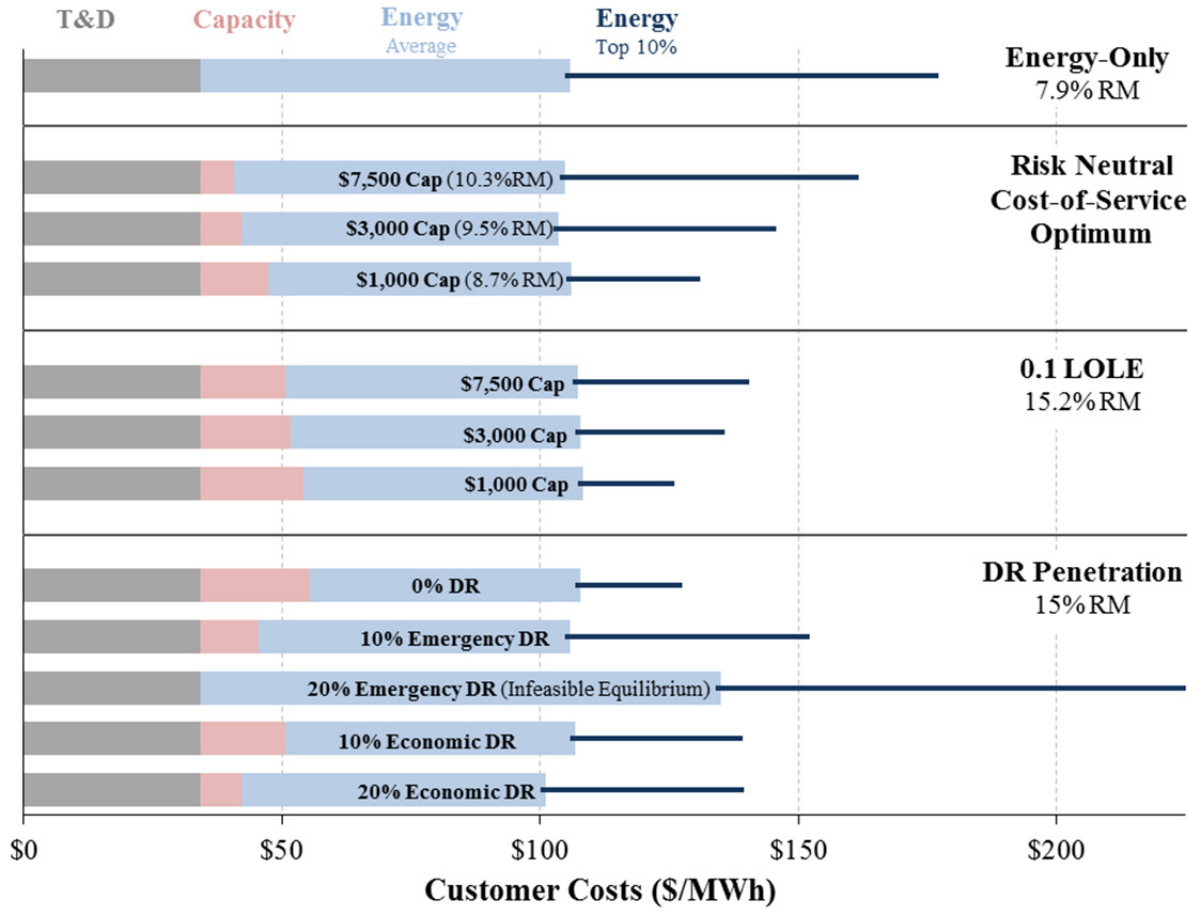
Notes:
Study RTO Base Case results, with customers paying market prices for energy and capacity.
Sensitivity bars shows annual customer cost averaged for 10% of the most expensive years, assuming full exposure to spot energy market uncertainty (*i.e.*, no LSE risk mitigation through seasonal or longer-term forward contracting).
Average T&D costs are a 2011 U.S. national average, see EIA (2013b).

This modest increase in average annual customer costs also achieves a risk mitigation benefit. As indicated by Figure 43, at the 7.9% planning reserve margin annual customer costs are likely to rise as high as $177/MWh once in ten years if those customers are fully exposed to spot market uncertainty.[165] This once-per-decade cost exposure is 68% higher than the average expected cost. At the higher 15.2% planning reserve margin, the once-per-decade spot market cost exposure is only $140/MWh, or 31% higher than the average. In other words, increasing planning reserve margins from 7.9% to 15.2% increases the average annual costs by $1.63/MWh but decreases the once-per-decade spot market cost exposure by $38/MWh or by approximately 36% of the total bill. As discussed earlier, however, this comparison will overstate the risk mitigation benefit of higher planning reserve margins because a large portion of all spot market uncertainties can be hedged readily by LSEs even on a relatively short-term basis, such as through forward contracting for an upcoming summer season.

[165] This expected cost is calculated as the average expected cost of the top 10% of the most expensive energy price years, *i.e.*, the expected cost of the most extreme year in any particular decade. All percentages reported are calculated as a percent of the total customer bill in the average year at the 7.9% reserve margin.

Figure 44 similarly shows average customer costs and once-per-decade spot market exposure under different energy-only and capacity market designs, planning reserve margins, price caps, and DR penetration levels. Again, the directional changes in energy and capacity costs mirror the changes observed for supplier net revenues in the previous section. As noted above, the annual average of total customer costs can change by 1% to 2% under different planning reserve margins and price caps. However, an unhedged customer's exposure to high-cost years would be much higher at lower reserve margins, with higher energy market price caps, and with higher DR penetration levels (particularly if that DR is Emergency DR rather than Economic DR). Also note that average annual customer costs in our simulations are as much as 5% lower at a high 20% economic DR penetration level, due to the reduction in overall generating capacity needs in combination with lower capacity prices that would result if such a substantial resource base of relatively low-cost DR were available.

Figure 44
Average Annual Customer Costs for Different Market Designs and System Conditions



Notes:

Study RTO Base, Price Cap, and DR Penetration Cases results, with customers paying market prices.

Sensitivity bar shows annual customer cost averaged for 10% of the most expensive years, assuming full exposure to spot energy market uncertainty (*i.e.*, no LSE risk mitigation through seasonal or longer-term forward contracting).

Average T&D costs are a 2011 U.S. national average, see EIA (2013b).

V. CONCLUSIONS

As we more fully explain in the Executive Summary, this study documents a wide range of accounting and methodological conventions that make reserve margins and resource adequacy assessments very difficult to compare across regions. Regions that appear to adopt the same 1-in-10 resource adequacy standard may in fact apply very different standards. For example, we demonstrate that in a hypothetical system under identical methodological assumptions, the 1-in-10 standard may require a planning reserve margin anywhere from 8.2% to 19.2% depending on: (a) whether 1-in-10 is interpreted as 0.1 LOLE or 2.4 LOLH; and (b) whether only load-shedding constitutes a reliability event or whether voltage reductions and operating reserves shortages may also be classified as "events."

Relatively few North American regions currently evaluate the economic implications of their resource adequacy standards, with the exceptions being several entities in SERC. Evaluating the economics of resource adequacy standards is a difficult modeling challenge and involves a complex set of questions and tradeoffs among total cost, reliability, and risk of extreme events. However, unless these questions are explicitly evaluated, policy makers will not be in a position to make informed choices among their competing economic and reliability objectives.

In our illustrations for a hypothetical system, we show that, depending on how a regulator's economic objectives are defined, the "optimal" reserve margin may be 7.9% from a societal perspective, 10.3% from a cost-of-service perspective, or possibly higher if regulators incorporate risk mitigation benefits into their decision-making. In this and other studies, we demonstrate that the likelihood of extreme reliability and wholesale price spike events can be substantially mitigated by increasing reserve margins with only a modest increase in customer costs. For example, increasing the reserve margin from the 7.9% "socially optimal" level to the 15.2% required to maintain 0.1 LOLE increases customer costs by approximately 1.5%.

In implementing their resource adequacy objectives, policy makers may use a number of different planning or market-based approaches. We specifically evaluate the economics of resource adequacy under energy-only and capacity market designs. As has been theoretically discussed elsewhere, we demonstrate through our modeling results that a perfectly efficient energy-only market will achieve the socially optimal reserve margin in expectation. However, we caution that no market design is perfect and so energy-only markets may be susceptible to either: (a) under-investment, if wholesale prices are artificially suppressed by low price caps or insufficient administrative scarcity pricing measures; or (b) over-investment, if wholesale prices are kept artificially high by factors such as sustained exercise of market power. Further, even if an energy-only market achieves a socially optimal level of investments, it may or may not achieve other policy objectives such as maintaining resource adequacy as defined by the 1-in-10 standard.

If regulators of restructured power markets wish to maintain a reserve margin higher than what an energy-only market will likely support, they may implement a resource adequacy standard within a competitive capacity market. Under a capacity market design, system operators can achieve their resource adequacy target and suppliers will earn sufficient revenues from the capacity market to attract the desired level of new entry. This is true even if wholesale energy market prices may be artificially suppressed, for example during scarcity conditions.

Overall, average customer costs are not substantially impacted by market design in the long term, except to the extent that different market designs may sustain different reserve margin levels over the long term. Customer costs are much more heavily impacted by fundamental factors such as fuel prices, load shape, and the cost and mix of supply resources. In particular, incorporating substantial quantities of DR resources into wholesale capacity and energy markets can increase the efficiency of those markets and also reduce customer costs to the extent that substantial quantities of low-cost DR opportunities exist.

LIST OF ACRONYMS

1-in-10	One-Day-In-Ten-Years
AESO	Alberta Electric System Operator
APC	Adjusted Production Costs
APS	Arizona Power Service
APSC	Arizona Public Service Company
BPA	Bonneville Power Administration
CAISO	California ISO
CBM	Capacity Benefit Margin
CBO	Congressional Budget Office
CC	Combined Cycle
CEC	California Energy Commission
CEER	Council of European Energy Regulators
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
CRS	Congressional Research Service
CT	Combustion Turbine
CVaR	Conditional Value at Risk
DR	Demand Response
EC	European Commission
EFORd	Expected Forced Outage Rate Data
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ENS	Energy-Not-Served
EOP	Emergency Operating Procedure
ERCOT	Electric Reliability Council of Texas
ETIP	Energy Technology Innovation Policy
EWITS	Eastern Wind Integration Transmission Study
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generation Availability Data System
GDP	Gross Domestic Product
GE-MARS	General Electric – Multi-Area Reliability Simulation

GEN	Generation
GTRPMTF	Generation and Transmission Reliability Planning Models Task Force
HR	Hour
ICAP	Installed Capacity
IESO	Independent Electricity System Operator
IRM	Integrated Resource Management
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kW-y	Kilowatt Year
kW-yr	Kilowatt Year
kWh	Kilowatt Hour
KU	Kentucky Utilities Company
LFG	Landfill Gas
LGE	Louisville Gas and Electric Company
LOLE	Loss of Load Event
LOLEWG	Loss of Load Expectation Working Group
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTA	Long-Term Adequacy
LTRA	Long-Term Reliability Assessment
MAPP	Mid-Continent Area Power Pool
MARS	Multi-Area Reliability Simulation
MATS	Mercury and Air Toxics Standard
MIS	Mission: Integrated Systems (MIS Energy Management)
MMbtu	Million Metric British Thermal Units
MISO	Midcontinent, formerly Midwest, ISO
MW	Megawatt
MWh	Megawatt Hour
NEM	National Energy Market
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPC	Nevada Power Company
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NRRI	Natural Resource Research Institute

NWPP	Northwest Power Pool
NYISO	New York ISO
NYSRC	New York State Reliability Council
PJM	PJM Interconnection
PNM	Public Service Company of New Mexico
PNW	Pinnacle West Capital Corporation
POLL	Probability of Lost Load
PPA	Power Purchase Agreement
PRISM	Parameter-Elevation Regressions on Independent Slopes Model
PRM	Planning Reserve Margin
PtP	Point-to-Point
PV	Photovoltaic
RES	Regulatory and Economic Studies
RFC	Reliability*First* Corporation
RM	Reserve Margin
RPM	Reliability Pricing MODEL
RTO	Regional Transmission Organization
RWG	Resource Working Group
SCE&G	South Carolina Electric & Gas Company
SCR	Special Case Resource
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SoCo	Southern Company
SPP	Southwest Power Pool
SWIS	South West Interconnected System
T&D	Transmission and Distribution
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
USE	Unserved Energy
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council

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APPENDICES

In these appendices, we provide supplemental information underlying the general discussion regarding: (a) our survey of resource adequacy standards in place across North America, as summarized in Section I.C above; and (b) our simulation assumptions for analyzing the reliability and economic implications of resource adequacy, as summarized in Section II above. These details are provided in Appendices A and B respectively.

A. DETAIL ON SURVEY OF NORTH AMERICAN RESOURCE ADEQUACY CRITERIA

B. DETAIL ON SIMULATION MODELING AND ASSUMPTIONS

A. Detail on Survey of North American Resource Adequacy Criteria

In this Appendix, we report additional detail from our survey of resource adequacy criteria used in U.S. and Canadian power systems, as summarized in Section I.C above. However, as noted above, to completely understand the nuances and complexities of these studies, one would need to discuss implementation details with the individuals responsible for implementing the studies. The public documentation of these studies is often insufficiently detailed or can easily be misinterpreted. Because we have not conducted such interviews to be able to document reliably the assumptions and the complexities of each study, our discussion should be interpreted as a summary of general industry practices, not a fully-verified documentation of any one region's approach.

1. Resource Adequacy Standards Used Across North America

Table 14 is a summary of resource adequacy standards across U.S. and Canadian power systems, as discussed in Section I.C.1 above.

Table 14
Survey of Resource Adequacy Criteria Across U.S. and Canadian Power Systems

Region	Standard	Model	Notes
PJM[(a)]	0.1 LOLE	PRISM and GE-MARS	The LOLE based target reserve margin and various other calculations provide key inputs into the PJM capacity market.
MISO[(b)]	0.1 LOLE	GE-MARS	Performed Annually by the ISO. Regional reserve margin of 16.7% but after diversity allows its load serving entities to carry an 11.3% reserve margin.
NYISO[(c)]	0.1 LOLE	GE-MARS	Resulted in a reserve margin of 16.1% for the period May 2012 to April 2013. Reserve Margin calculation includes nameplate of all resources including wind. Results are adapted to derated UCAP for implementation in the NYISO capacity market.
ISO-NE[(d)]	0.1 LOLE	GE-MARS	2012 ICR report calculates the requirement needed to meet its 1 day in 10 year standard, load uncertainty considers weather but not economic forecast error. Results used capacity market.
SPP[(e)]	2.4 LOLH	ABB Grid View	Capacity margin criterion of 12% for RTO members that are steam based and 9% for hydro based; results in capacity margin criterion above the 1 day in 10 year definition.
Maritimes [(f)]	20% RM and 0.1 LOLE	NPCC uses MARS	Maritimes uses a 20% reserve margin criterion for planning purposes but at the same time adheres to the NPCC requirement of not shedding firm load more than 1 day in 10 years.
Quebec[(g)]	0.1 LOLE	NPCC uses MARS	Based on an LOLE of 0.1, Quebec requires a 10% reserve margin for the 2012/2013 winter peak. By the 2015/2016 winter peak, Quebec requires a 12.2% reserve margin. Because of its dependence on hydro generation, Quebec also imposes an energy requirement to withstand 2 consecutive years of low water inflows.
IESO[(h)]	0.1 LOLE	NPCC uses MARS	The target for 2013 to meet the one day in 10 year target is 19.7% in which the region meets easily with an anticipated reserve margin of 40.1%.
Saskatchewan[(i)]	EUE Standard		Sask Power uses a 13% RM based on probabilistic analysis of Expected Unserved Energy.
Manitoba[(j)]	Both RM and energy standards due to hydro dependence		The energy criterion requires adequate energy resources to supply firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The capacity reserve margin is at least 12%.
MAPP[(i)]	1 day in 10 years (LOLE of 0.1)		Some MAPP members self-impose a planning reserve margin of 15% based on the results of an LOLE study performed in 2009.
SERC/ General	No mandatory requirement		RA targets set by individual load serving members subject to regulatory review. With this approach, the criteria and final reserve margins vary across the region.
SERC/SoCo[(k)]	Economics	SERVM	The target is based on minimizing customer costs.

Region	Standard	Model	Notes
SERC/Duke Energy Carolinas[l]	0.1 LOLE and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/ Progress Energy Carolinas[m]	1 day in 10 years (LOLE of 0.1) and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/TVA[n]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/Santee Cooper[o]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ LGE&KU[p]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ Entergy[i]	1 day in 10 years (LOLE of 0.1)	ERAILS	
SERC/ SCE&G[q]	12–18% RM		
FRCC[r]	0.1 LOLE	Tiger	"The FRCC has a resource criterion of a 15% minimum Regional Reserve Margin based on firm load. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion."
ERCOT[s]	0.1 LOLE target (not mandatory)	Internal Model	ERCOT operates as an energy-only market and so does not mandate a RM; but performs one day in 10 year standard assessment to inform ERCOT and
WECC/ General[t]	No mandatory requirement		Individual balancing areas within WECC determine their own resource adequacy requirements in various ways and are subject to review by state regulators
CAISO[u]	15% RM		In January 2004, the CPUC established a long-term Resource Adequacy framework (D.04-01-050). This decision adopted a 15% to 17% planning reserve margin (PRM) and directed that each LSE is responsible for acquiring sufficient reserves to meet its own customer load. CAISO has since performed LOLE studies but the studies have not impacted the decision made in 2004 to maintain at a minimum 15% reserve margin
Northwest/ BPA[v]	Loss-of-Load Probability (LOLP) of 5%; and conditional value at risk (CVaR) to evaluate energy not served (ENS) events	Genesys Model	A completely different method from 1 day in 10 years. Method was developed in cooperation with the Northwest Council to take into account the predominantly hydro resource mix of the Northwest. For this use, LOLP is not defined as hours per year. It is instead a percentage of iterations that contain any EUE. The target allows no more than 5% of all iterations to contain EUE.
Southwest/ APS[w]	0.1 LOLE		APS 2012 IRP states that at 15% planning reserve margin criterion, LOLE is less than 1 day in 10 years.
Southwest/ PNW[x]	NM State Commission set target at 13%		Notes that reserve margin would likely increase if a one day in 10 year standard were used.
Southwest/ NV Energy[y]	1-in-10		Definition of 1 day in 10 years is not reported.
Alberta	No RA requirement		Intervention possible if expected EUE over a two-year outlook increases above 1,600 MWh.

Sources:

From regional resource adequacy studies: (a) PJM (2011); (b) MISO (2011); (c) NYSRC (2011); (d) ISO-NE (2011); (e) SPP (2010); (f) NBSO (2011); (g) Hydro-Québec (2011); (h) IESO (2012); (i) NERC (2011a); (j) Manitoba Hydro (2010); (k) Georgia Power (2010); (l) Duke (2012); (m) Progress (2012); (n) TVA (2011); (o) 2012 IRP, forthcoming; (p) LG&E and KU (2011); (q) SCE&G (2011); (r) FRCC (2012); (s) ERCOT (2012); (t) WECC (2011); (u) CPUC and CEC (2005); (v) BPA (2011); (w) APS (2012); (x) PNM (2011); and (y) Nevada Power (2012).

2. Illustration of Differences in Resource Adequacy Modeling Assumptions

Table 15 shows an illustrative comparison of select model assumptions as used in various regions' reliability planning studies, as discussed in Section I.C.3 above.

Table 15
Summary Comparison of Select Regions' Reliability and Resource Adequacy Studies

	ISO-NE	PJM	NYISO	MISO	SPP	SoCo
Reliability Event Definition	Maintain 200 MW of operating reserves when shedding firm load; voltage reduction and demand resources are deployed before shedding firm load.	Firm load shed after deploying interruptible and depletion of 30 minute reserves, but before voltage reduction or depletion of 10 minute reserves.	Firm load shed after depletion of 30 and 10 minute reserves, and calling voltage reduction. Emergency Operating Procedures also anticipate some benefit from voluntary curtailment and public appeals.	Firm load after all operating reserves are depleted and system is just able to sustain frequency with no regulation. No mention of voltage control. DR is removed from load before simulation and is therefore treated as deployed.	Not explicitly defined.	Before firm load shed, all voltage reduction options are exhausted. Firm load will be shed to maintain the full operating reserve requirement including spinning and non-spinning reserves.
Reserve Margin Accounting	Reliability requirement reported both including and excluding portion of tie benefits; intermittent resource values derated.	Nameplate capacity for thermal resources; derate wind and solar according to expected reliability benefit. Does not include voltage reduction.	Nameplate capacity for all resources; does not include voltage reduction.	Nameplate capacity for thermal resources but derate wind.	Nameplate capacity for thermal resources; derate wind and solar according to expected reliability benefit. Does not include voltage reduction.	Voltage reduction treated as a supply resource. Derate interruptible and intermittent resources according to their expected reliability benefit.
Neighbor Assistance	Uses a tie benefit of 1,676 MW that is modeled as a resource; different treatment of firm and non-firm imports.	Model external areas with diversity of weather and unit performance, up to a maximum assumed non-firm import capability of 3,500 MW.	Model external areas with same load shape during peak events.	Model 7 external regions at their planning reserve margin levels. Neighbors provide assistance until all operating reserves are depleted. Assumes 9,000 MW of import capability.	Assume 0 MW from outside areas.	Model neighbors' load and resource diversity.
Model	GE-MARS	GE-MARS and PRISM	GE-MARS	GE-MARS	ABB Grid View	SERVM

Sources:
ISO-NE (2012); PJM (2011); NYSRC (2011); MISO (2012c); SPP (2010); and Georgia Power (2010).

B. Detail on Simulation Modeling and Assumptions

The most important modeling assumptions implemented in our study as well as a general description of how these assumptions are implemented within SERVM are documented in Section II within the body of this report. We supplement that more general discussion within this Appendix by providing additional supporting detail on our assumptions regarding: (1) intertie availability; (2) forced and maintenance outage modeling for thermal resources; (3) hydro resource modeling; (4) intermittent resource modeling; and (5) weather uncertainty and load modeling.

1. Interregional Tie Line Availability

As explained in Sections II.A-B, SERVM uses a transmission-constrained economic dispatch to schedule power flows among regions. We simulate the availability of each intertie over a probability distribution between 60% and 100% of the path rating. For simplicity, we assume that the interties are simultaneously feasible and that the availability of any one intertie is independent of the others' availability. Figure 45 shows the non-simultaneous import capability of each path, while Figure 46 shows the simultaneous import capability of the Study RTO from all directions. The maximum simultaneous import capability to the Study RTO Region is 11,000 MW, although it is less than 8,000 MW in 50% of all hours.

Figure 45
Non-Simultaneous Tie-Line Availability Distributions

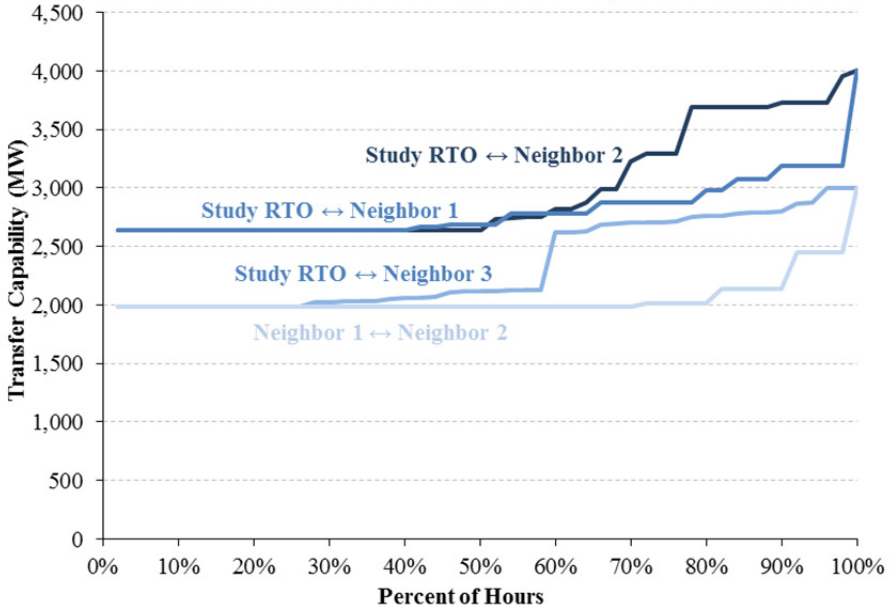
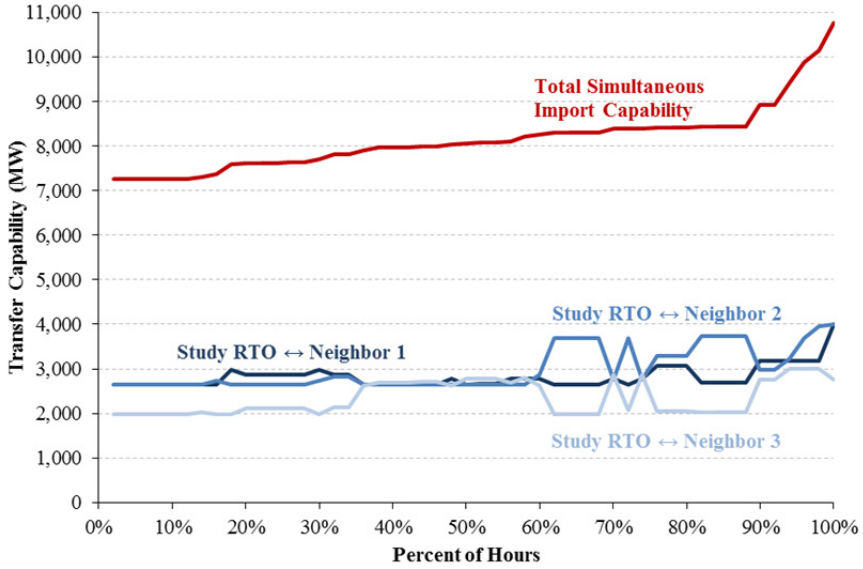


Figure 46
Simultaneous Study RTO Import Capability



2. Thermal Resource Forced and Maintenance Outage Assumptions

We provide here additional detail regarding how SERVM captures the probability of forced and maintenance outages for thermal resources. Average resource availability is consistent with NERC Effective Forced Outage Rate (EFORd) data from 2006–2010 by unit type and size.[166] Unlike most production cost and reliability models, SERVM does not use an average outage rate for each unit to approximately capture unit availability. Instead, SERVM simulates unit outages using random event draws from representative probability distributions. We developed these distributions based on previous modeling work, and scaled these distributions to match the national average outage rates. We also vary the outage rates seasonally to capture different operating profiles in summer, shoulder, and winter months.

[166] From NERC (2011b).

Specifically, outage events are characterized by the probability distributions around the following variables for full, partial, and maintenance outages, with the fleet-average values of key parameters as summarized in Table 16:

Full Outages are characterized by distributions of: (1) Time-to-Repair Hours; and (2) Time-to-Fail Hours.

Partial Outages are characterized by distributions of: (1) Partial Outage Time-to-Repair Hours; (2) Partial Outage Derate Percentage; and (3) Partial Outage Time-to-Fail Hours.

Maintenance Outages are identified based on the percentage of full outages that have some scheduling flexibility. These outages are scheduled in off-peak periods to the extent feasible.

To further illustrate the outage modeling approach in SERVM, consider a unit with assumed distributions for Time-to-Repair after an event, Time-to-Fail between events, and the other variables listed above. If the unit is online in hour 1, SERVM will randomly draw Time-to-Fail values from the distributions for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is less than the selected full outage Time-to-Fail value. Next, the SERVM will draw a Time-to-Repair value from the distribution and be on forced outage for that number of hours. When the repair is complete, it will draw new partial-outage and full-outage Time-to-Fail values. The process repeats until the end of the simulated year, when it will begin again for the subsequent iteration. This detailed multi-state stochastic modeling captures the tails of the distribution over potential low-probability, high-impact reliability outcomes that a simple convolution method would not capture.

Table 16
Fleet-Average Outage Characteristics by Unit Type

Unit Type	Forced Outage Rate *(%)*	Mean Time to Repair *(hours)*	Mean Time to Fail *(hours)*
Nuclear	3.0%	146	6,454
Coal	6.8%	95	2,087
Biomass/LFG	8.4%	120	2,295
Gas Combined Cycle	5.0%	68	2,018
Gas Steam Turbines	7.0%	104	2,223
Steam Oil	6.2%	108	2,691
Gas Combustion Turbines	7.8%	47	551
Oil Combustion Turbines	11.8%	60	451
Overall Fleet	**6.3%**	**92**	**2,443**

Sources and Notes:
Represents fleet average values, weighted by units' nameplate capacity.
Mean time to repair and mean time to fail values exclude partial outages.
Forced outage data from the Generation Availability Data System (GADS), NERC (2011b).

3. Hydro Modeling

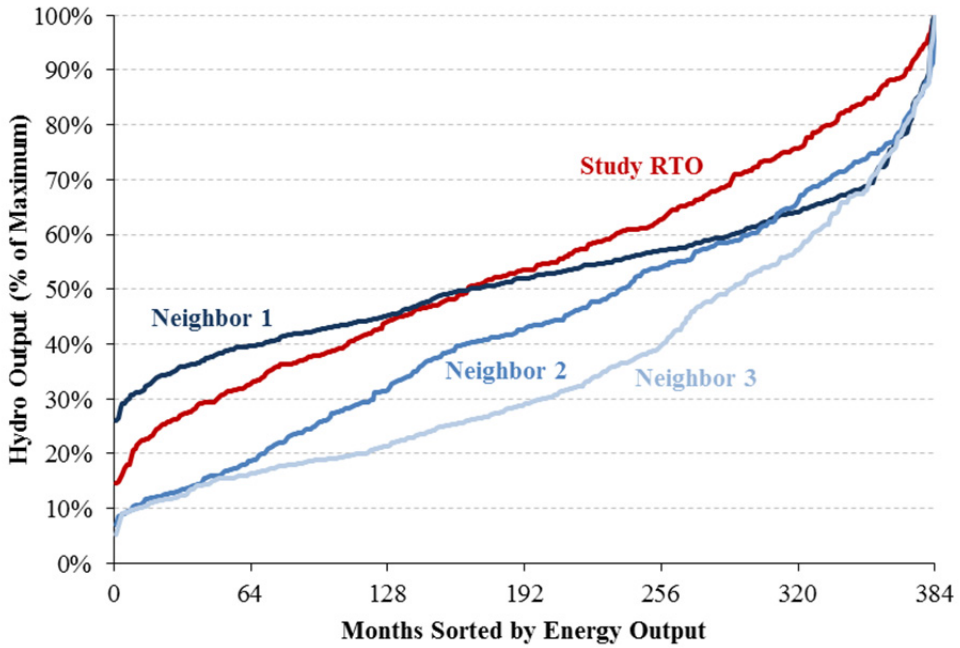
We model the hydro portfolio in each region based on segments treated as non-schedulable run of river, schedulable peak shaving hydro, and dispatchable emergency capacity. The run-of-river segment is dispatched as baseload capacity providing its designated capacity every hour of the year. The schedulable hydro is used for shaving the daily peak load, subject to minimum daily flow requirements. The emergency capacity is used only to prevent firm load shed, meaning that SERVM allows the emergency mode to "borrow" up to a few hours' worth of energy from future dispatch of the scheduled hydro output. Typically, hydro resources cannot dispatch at their nameplate capacity during peak hours due to water supply limitations or river flow requirements. By modeling hydro resources in these three segments, SERVM captures the likelihood that incremental hydro resources will be available during peak and emergency conditions.

Using FERC data on historical monthly hydro generation, we prepared resource availability profiles for the same regions and historical weather years used in our load modeling.[167] In years with little historical hydro generation, SERVM models correspondingly little generation and capacity available during peak conditions. In years with substantial historical generation, SERVM models a substantial portion of the hydro fleet in run-of-river status with additional dispatch flexibility during peak conditions. Extreme shortage events in which high load and low hydro conditions coincide are modeled in SERVM only to the extent that such conditions have been observed over the historical weather and hydro years that we examine.

Figure 47 shows the distribution of monthly hydro generation for each modeled region across the range of weather scenarios modeled. The figure also shows that not all modeled regions have the same level of reliability in their hydro resource, with Neighbor 1 having the most consistent hydro resource and Neighbor 3 realizing the most frequent low-hydro conditions.

[167] Data from EIA (2013).

Figure 47
Hydro Energy Variation by Month and Region



Sources and Notes:
Data adapted from actual systems' monthly hydro data as reported in EIA (2013).

4. Intermittent Resource Modeling

As explained in Section II.C.3 above, wind and solar resources are modeled as non-dispatchable intermittent resources. For wind resources, we use hourly EWITS data from years 2004–2006.[168] We aggregate these data by state, consistent with the weather stations we used in our load modeling to develop three years' worth of hourly wind profiles. SERVM randomly draws a date from within the month being simulated, and uses the daily wind profile from each region consistent with that date in order to maintain the appropriate inter-regional correlations in wind output. For example, if SERVM is currently simulating the month of July, it may randomly select the date July 5, 2006 as the basis for the wind profiles from all four regions.

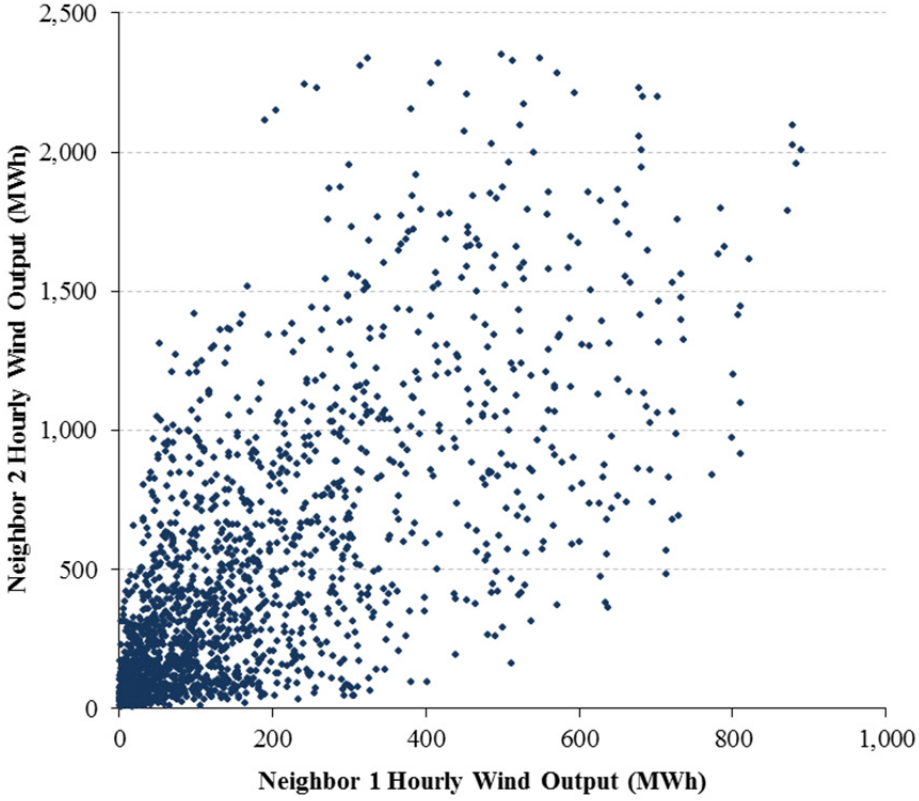
As demonstrated in Figure 48 for Regions 1 and 2 (based on EWITS wind profiles for central MISO and western PJM), there is some correlation in hourly wind output among neighboring regions, but this correlation is small compared to the total volatility in wind output. Consistent with the geography of weather and hydro conditions, we used aggregate EWITS wind profiles for Tennessee (with an annual capacity factor 31%) for the Study RTO.

We assume that solar capacity has a low penetration level in all regions that we model and so this resource has minimal impact on study results. We use PV Watts data to develop a typical hourly

[168] See NREL (2013a).

annual profile for each region.[169] Similar to wind, SERVM randomly draws a daily profile by month for the aggregated solar generation in each region.

Figure 48
Correlation in Hourly Wind Output in Neighbors 1 and 2 During Summer Peak Hours



Sources and Notes:
Data adapted from EWITS data for central MISO and western PJM, see NREL (2013a).

5. Treatment of Weather Uncertainty in Load Modeling

This section provides additional detail on how weather uncertainty is modeled, as summarized in Section II.D.1 above. Table 17 lists the weather stations used to represent the Study RTO and three neighboring systems.

[169] From NREL (2013b).

Table 17
Weather Stations Used to Represent Each Modeled System

Modeled System	Weather Stations
Study RTO	Chattanooga, TN Nashville, TN Knoxville, TN Huntsville, AL
Neighbor 1	Indianapolis, IN St. Louis, MO Springfield, IL
Neighbor 2	Columbus, OH Baltimore, MD Charleston, WV Richmond, VA
Neighbor 3	Atlanta, GA Birmingham, AL Mobile, AL Montgomery, AL Macon, GA

As explained in Section II.D.1, we estimate econometric relationships between recent historical loads and weather to develop 32 synthetic annul load profiles that are consistent with 32 years of historical weather data. The following three figures show the range of load profiles we model, with summer peak load in Figure 49, winter peak load in Figure 50, and total annual energy in Figure 51. In each case, the figures show the percentage by which the 99th percentile, 95th percentile, and 90th percentile extreme loads exceed the weather-normalized load.

As shown in Figure 28, extreme weather can cause peak load to substantially exceed the expected normal (*i.e.*, 50/50 peak load) condition. In fact, each region can expect actual peak load to exceed weather-normal peak load by more than 5% once every ten years solely due to weather conditions, with extremes of up to 9% in rarer cases. As shown in Figure 50, winter peak variance is highest for the Study RTO Region and Outside Region 3, although the duration of these peaks is shorter and the average winter peak is lower than the average summer peak. This means that most reliability events are still most likely to occur during the summer. Outside Regions 1 and 2 are only summer-peaking, and so cold weather events do not impact these regions substantially. Finally, as shown in Figure 51, annual energy does not vary as substantially as summer and winter peak loads because it takes into account all hours of the year, and many off-peak hours have more stable load profiles that are not as heavily influenced by weather.

Figure 49
Summer Peak Load in Extreme Years as Percent above Weather-Normal Peak

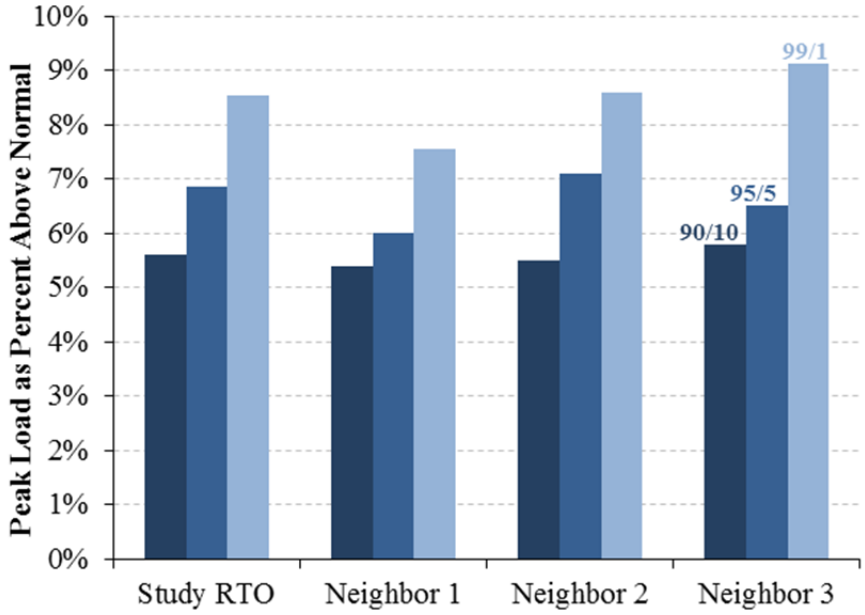


Figure 50
Winter Peak Load in Extreme Years as Percent above Weather-Normal Peak

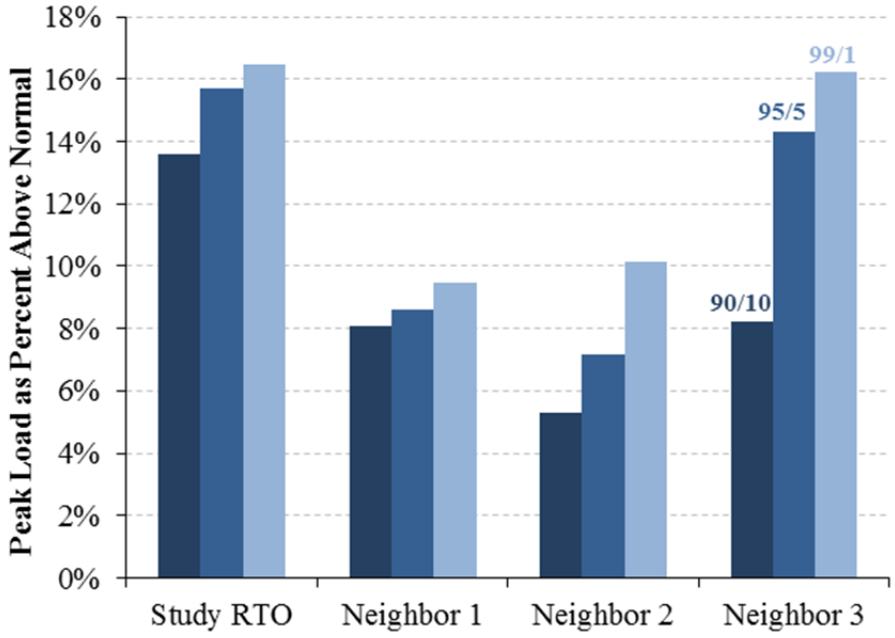
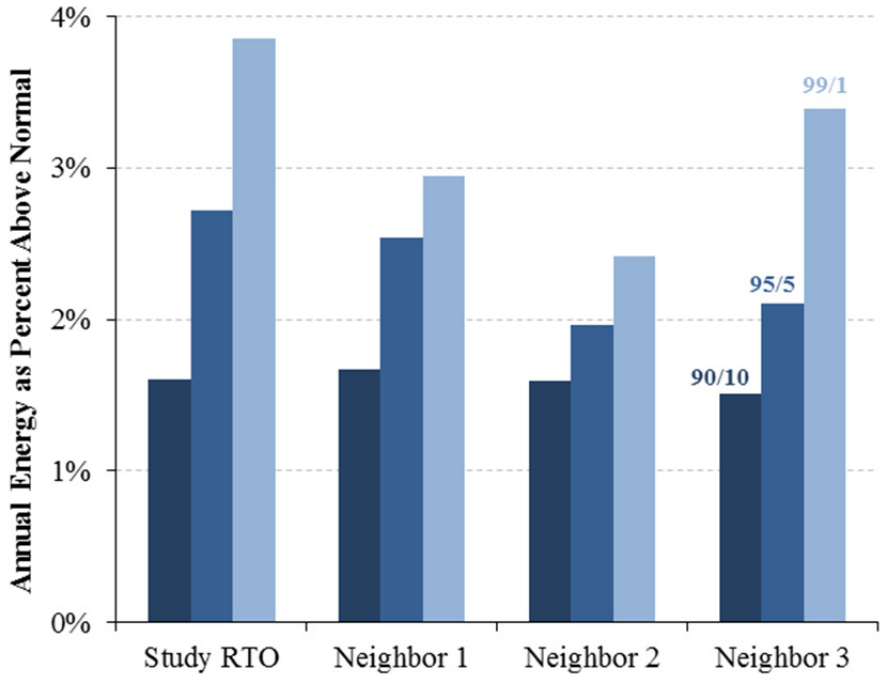
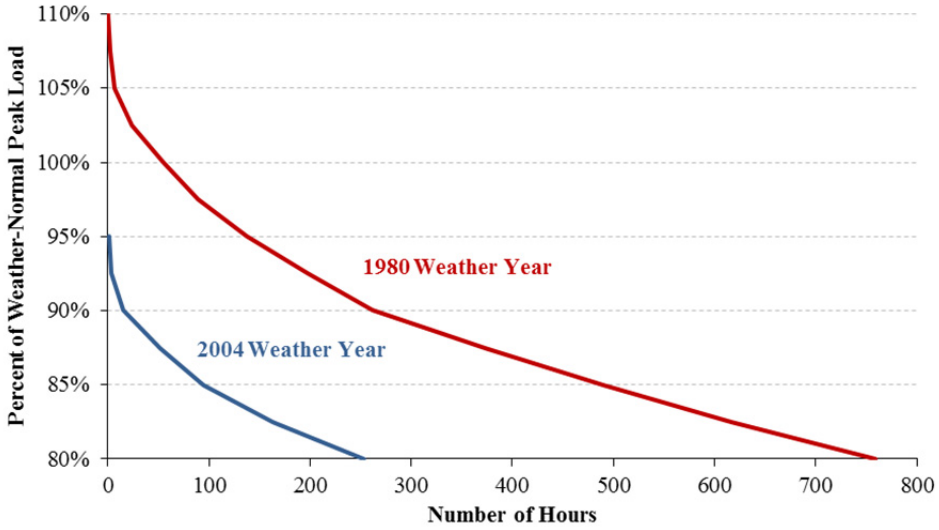


Figure 51
Annual Energy in Extreme Years as Percent above Weather-Normal Year



Reliability outcomes are also heavily influenced by the duration of severe temperatures, particularly because some summers may have extremely high temperatures for only a few days while other years' experience sustained high-cost events with high temperatures for the duration of the entire summer. For example, Figure 52 shows the load duration curve for the Study RTO Region relative to weather-normalized peak load for two years, one that has high relatively high system peak load and one relatively low peak load. Note that 2004 weather year produced a peak load of only 95% of the weather-normal peak load, while the 1980 weather year experienced a peak of 10% above normal, as well as a much larger number of high-load hours, driven by a sustained summer heat wave.

Figure 52
Duration of Extreme Hours



Finally, each region can expect some level of neighbor assistance during peaking conditions, since the systems will peak at slightly different times. Table 18 summarizes shows the load diversity between the Study RTO and the three neighbors in the weather-normal year, comparing non-coincident peak load to peak load during: (a) the multi-regional coincident peak; and (b) the Study RTO peak. Note that diversity between the Study RTO and Neighbor 3 is relatively low while the Study RTO has more diversity with Neighbors 1 and 2. This is important in our reliability simulations in that most neighbor assistance during the Study RTO's system peak will be available from these two regions. On a total system basis, the weather diversity reduces the individual regions' non-coincident peak load of 180,000 MW by 3% to a combined multi-region coincident peak of 174,668 MW.

Table 18
Load Diversity for Study RTO and its Neighbors
(During Multi-System Coincident Peak and Study RTO Peak)

	Peak Load			**Load Diversity**	
	Non-Coincident Peak *(MW)*	During Multi-Region Coincident Peak *(MW)*	During Study RTO Peak *(MW)*	Relative to Multi-Region Coincident Peak *(%)*	Relative to Study RTO Peak *(%)*
Study RTO	50,000	48,605	50,000	2.8%	0.0%
Neighbor 1	60,000	58,686	54,399	2.2%	9.3%
Neighbor 2	40,000	38,604	35,242	3.5%	11.8%
Neighbor 3	30,000	28,773	28,887	4.1%	3.7%
Total	**180,000**	**174,668**	**168,528**	**3.0%**	**6.4%**

EXHIBIT 131-4

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



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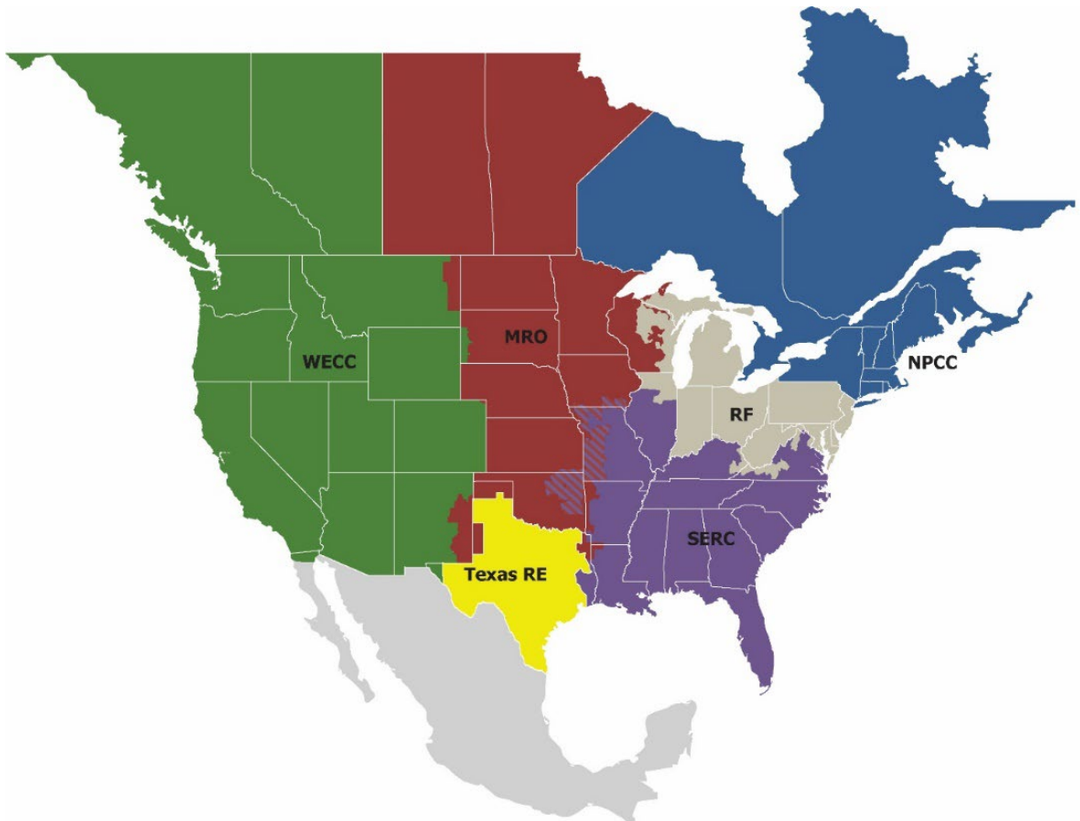
Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

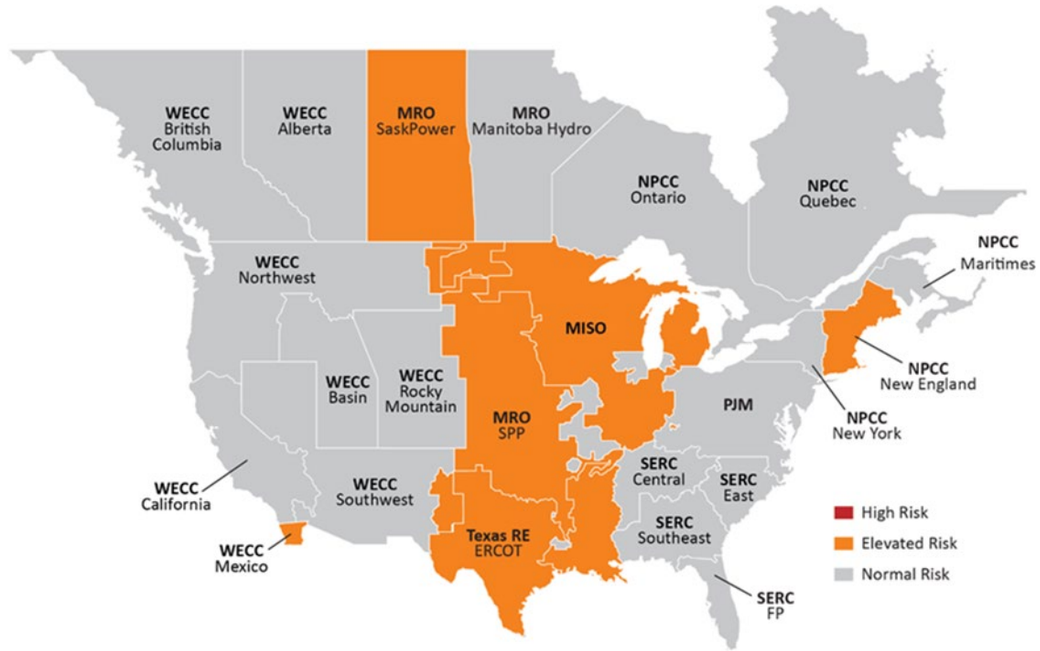


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

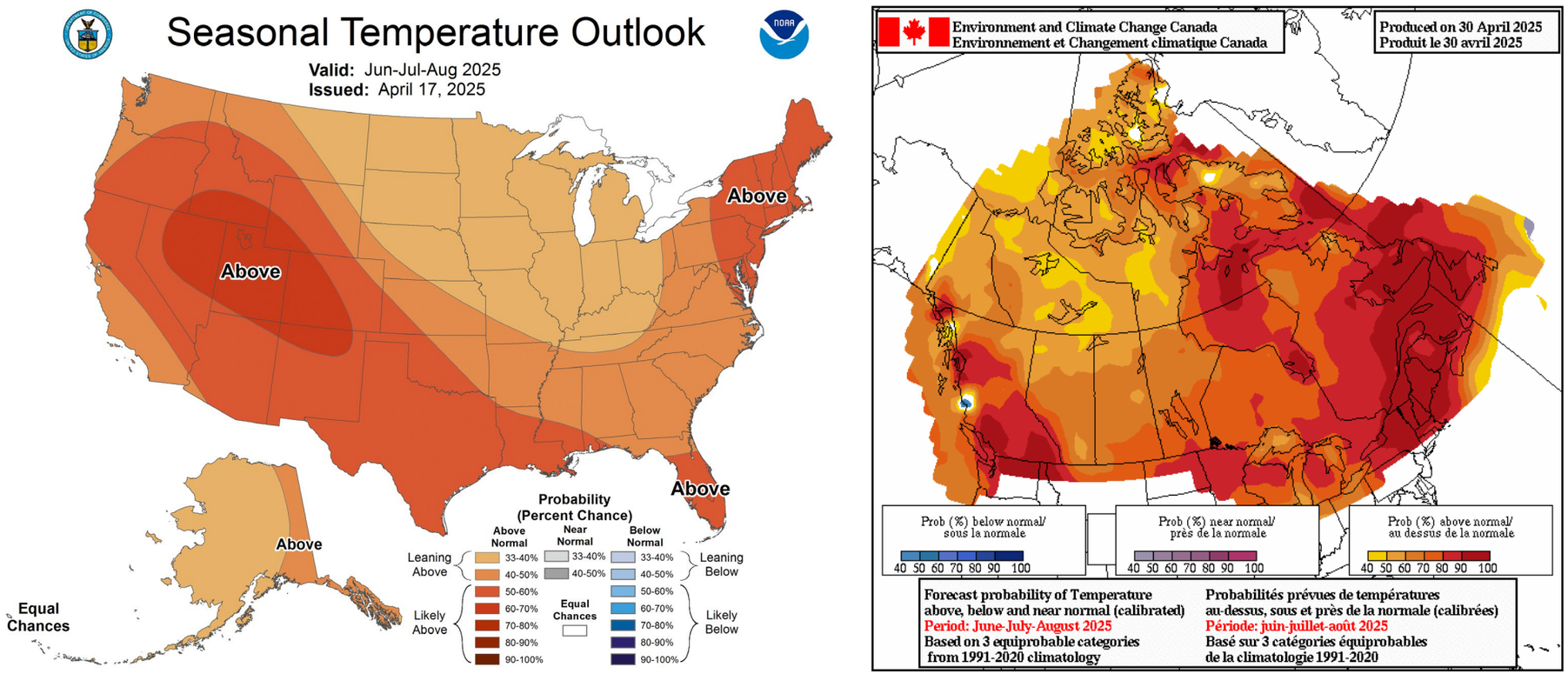


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

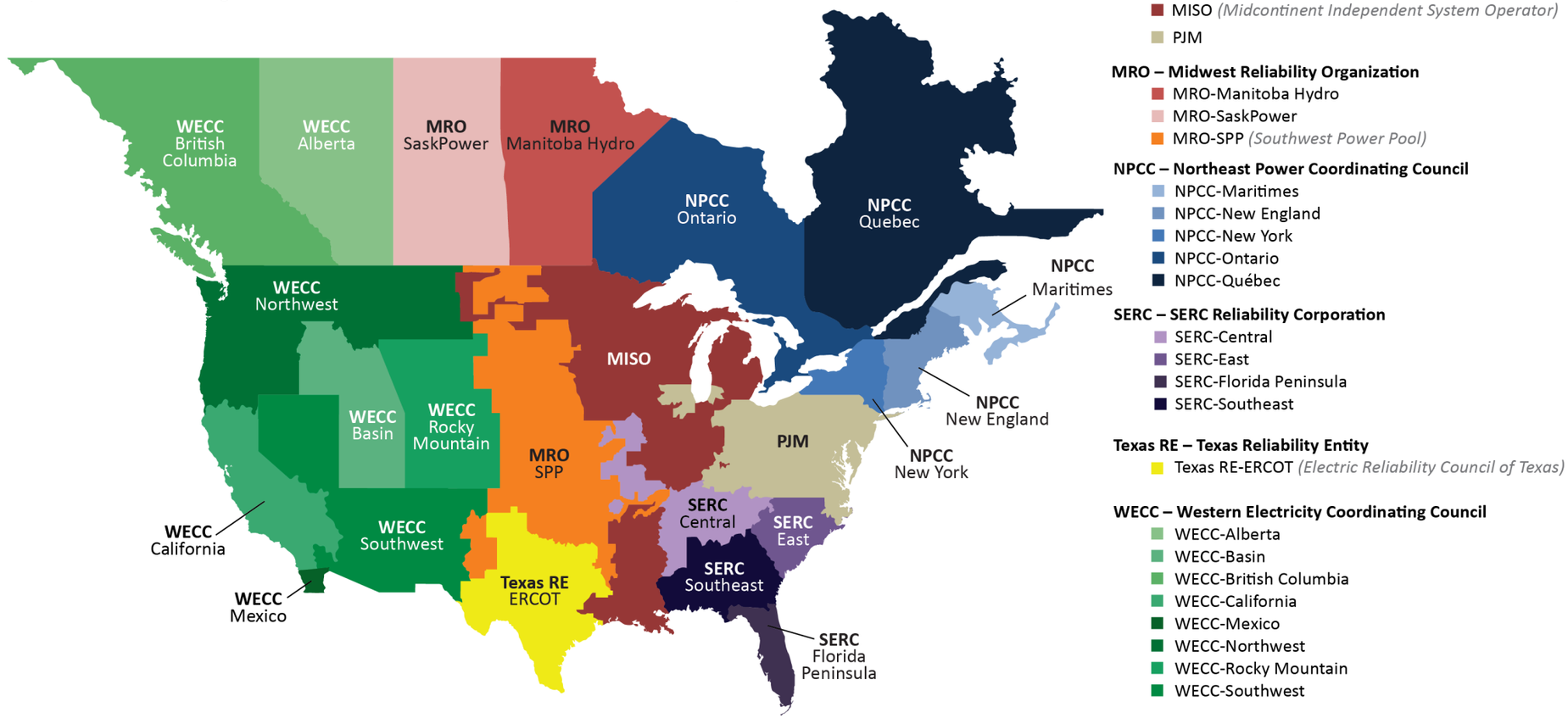
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

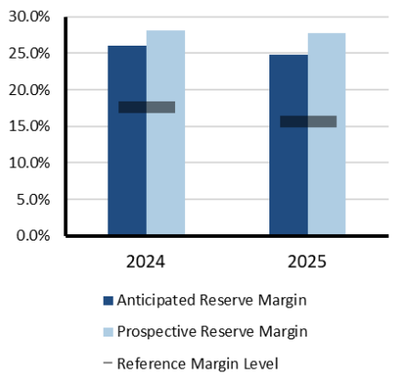
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

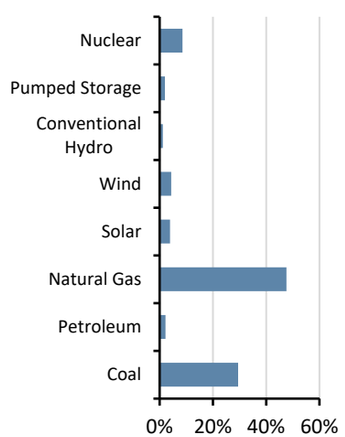
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

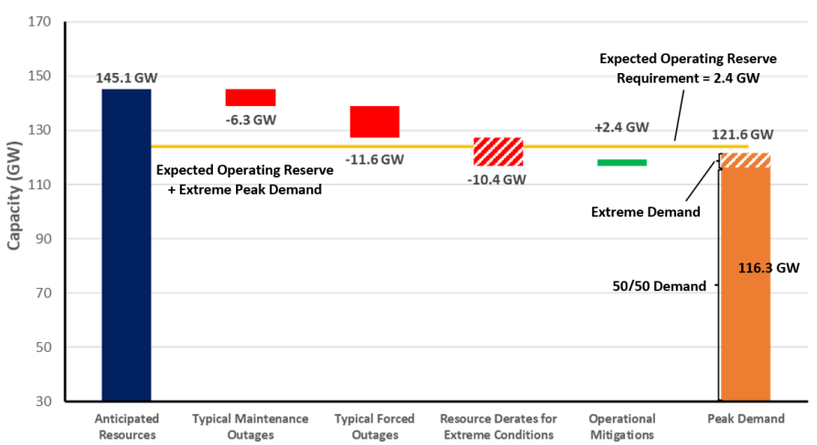
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

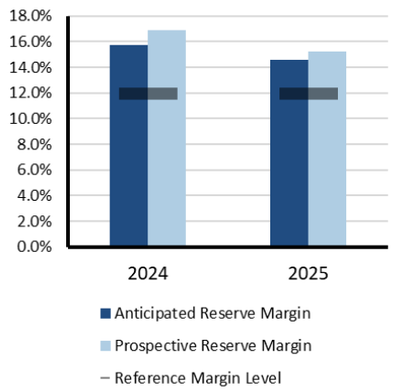
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

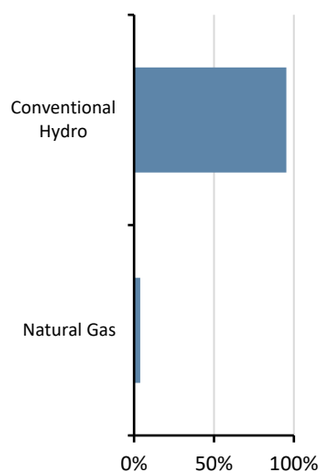
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

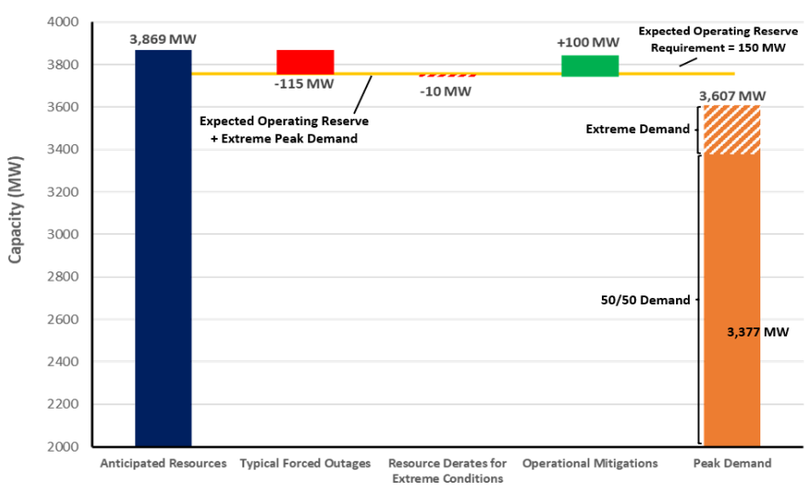
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

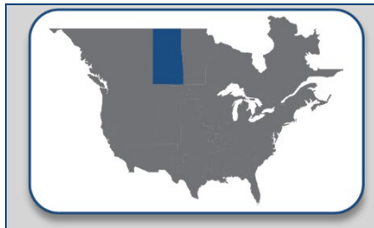
Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



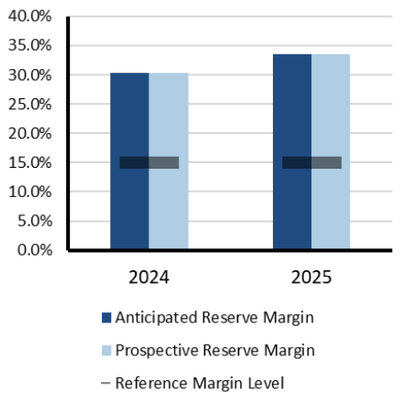
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

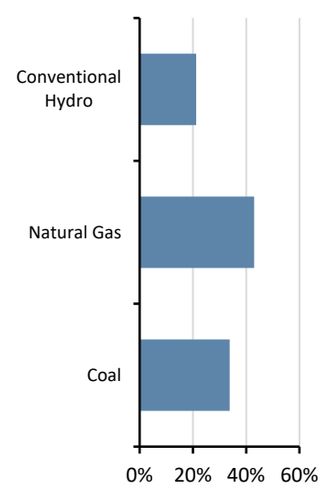
On-Peak Reserve Margin



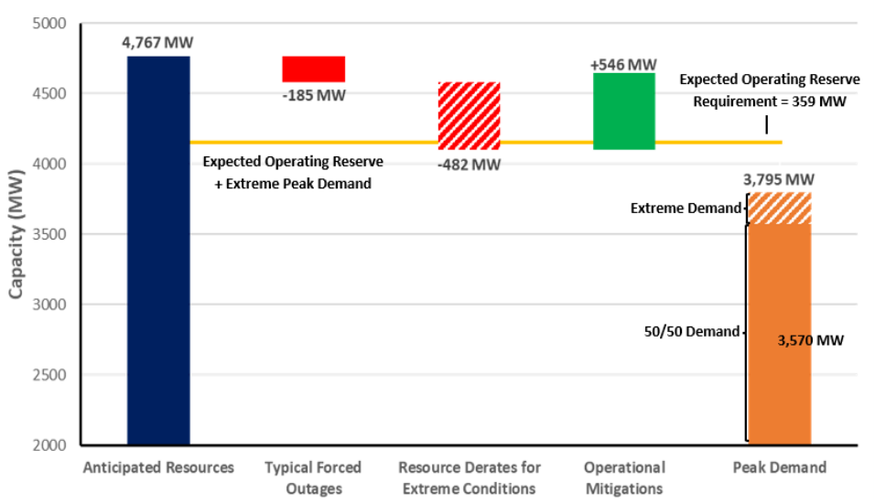
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

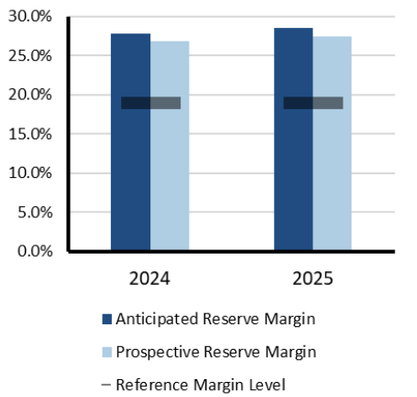
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

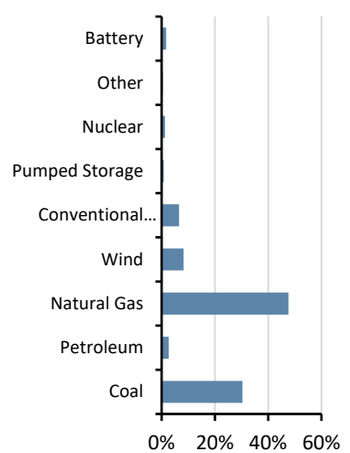
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

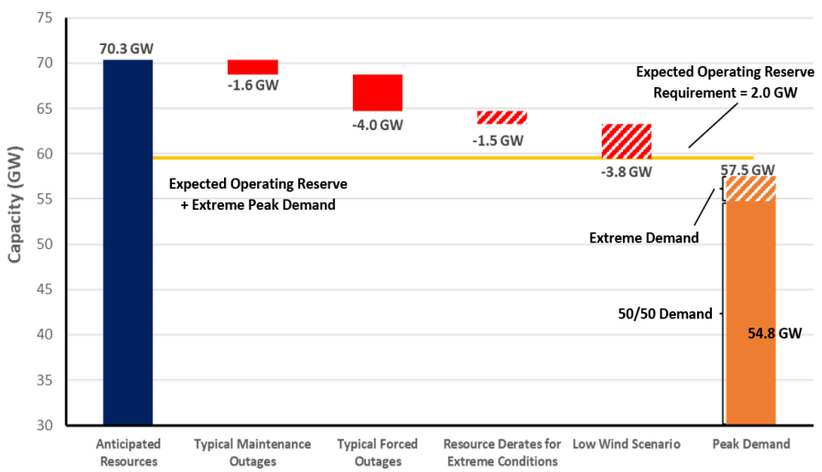
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



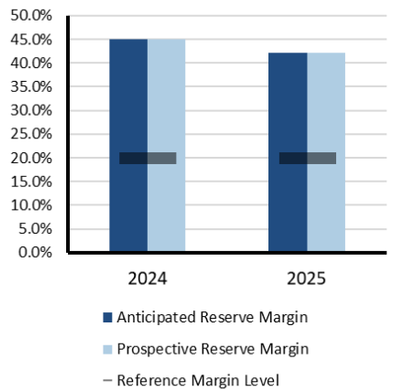
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

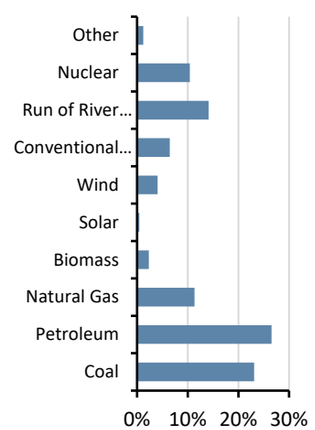
On-Peak Reserve Margin



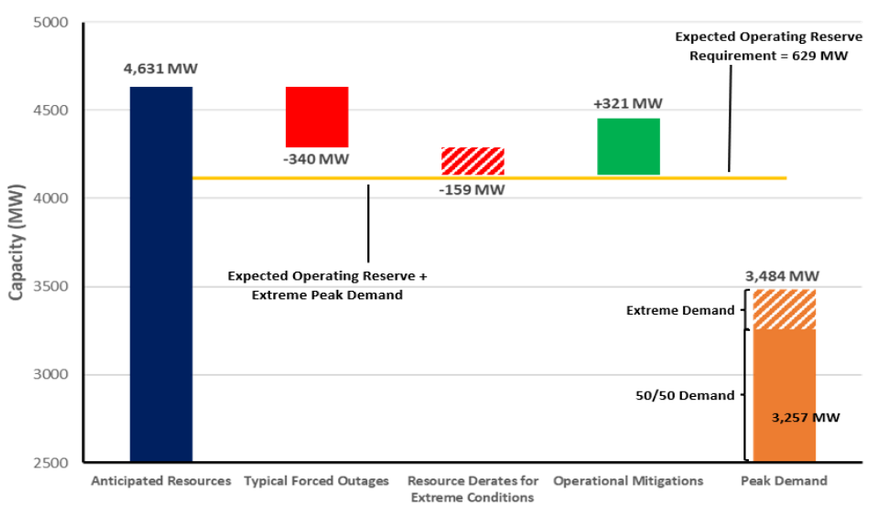
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)



NPCC-New England

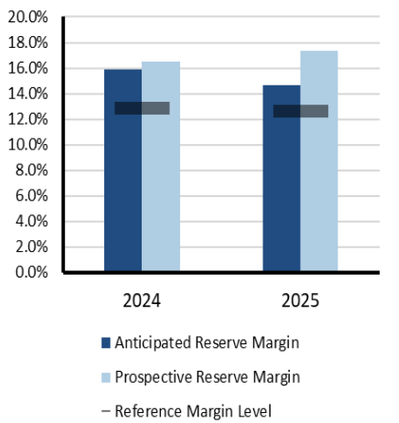
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

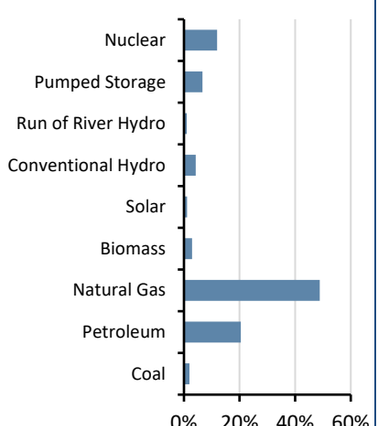
On-Peak Reserve Margin



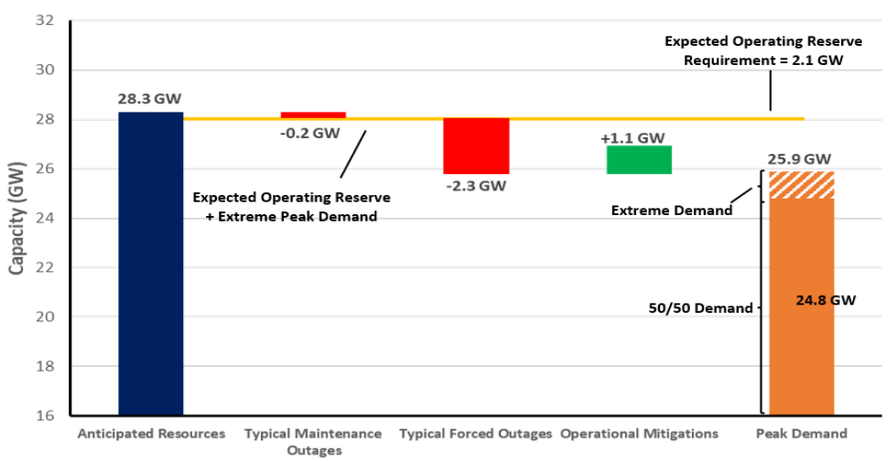
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



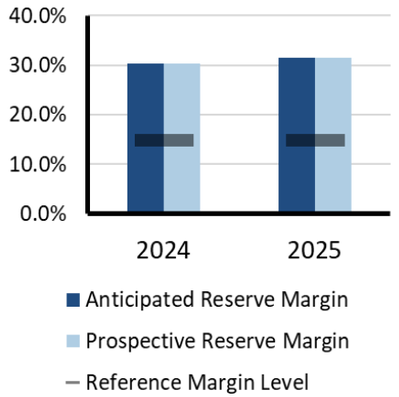
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

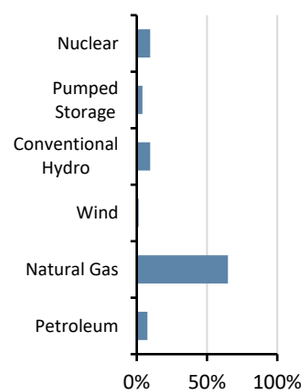
On-Peak Reserve Margin



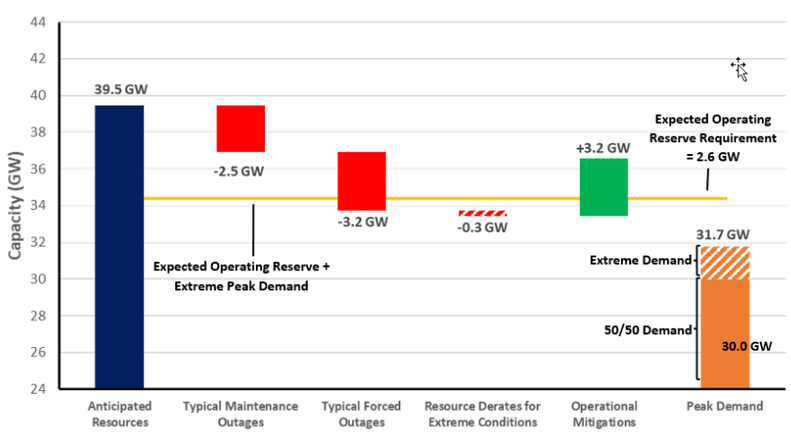
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

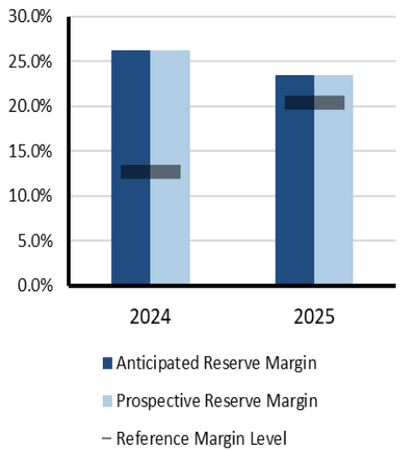
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

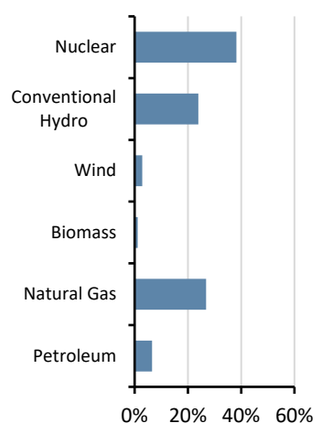
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

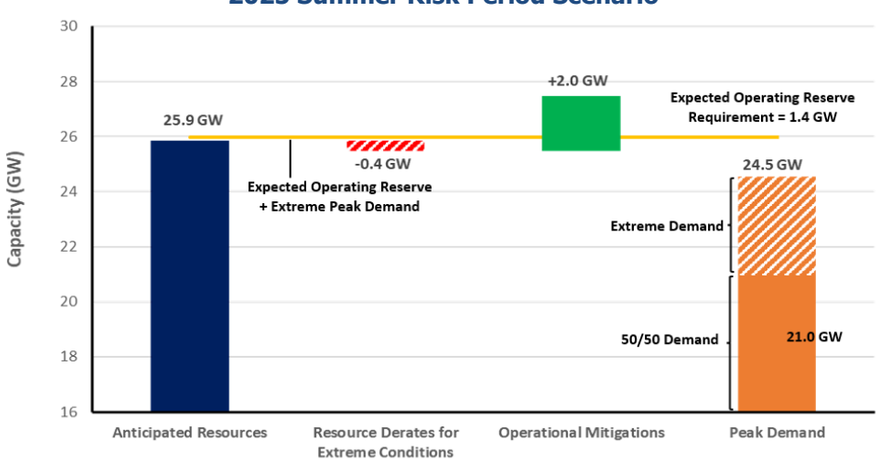
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.



NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

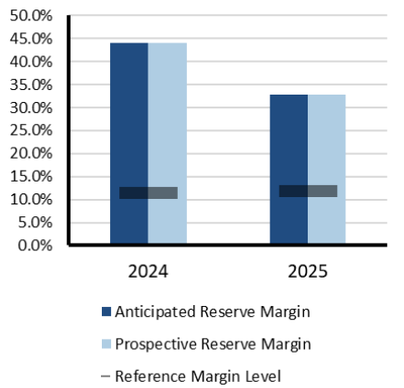
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

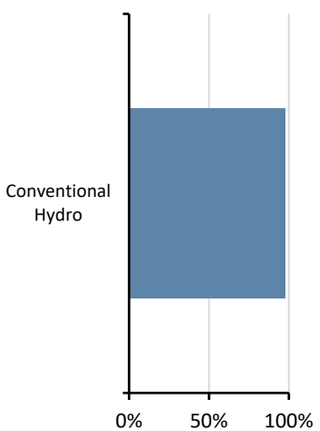
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

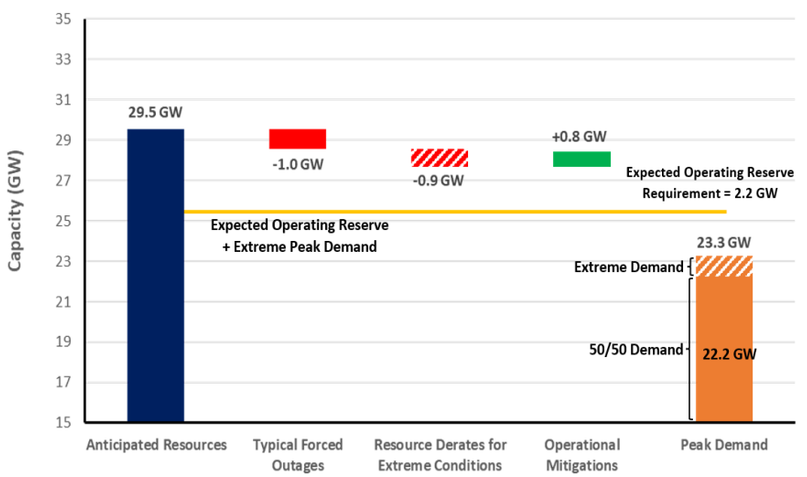
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

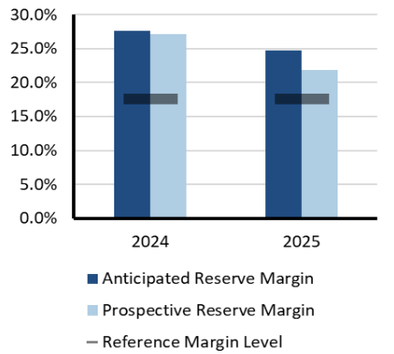
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

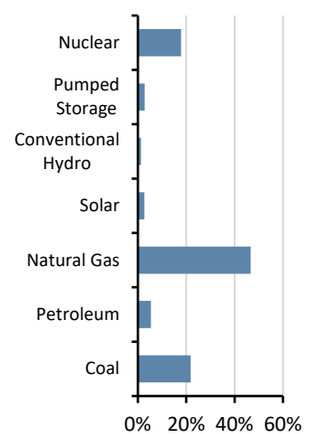
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

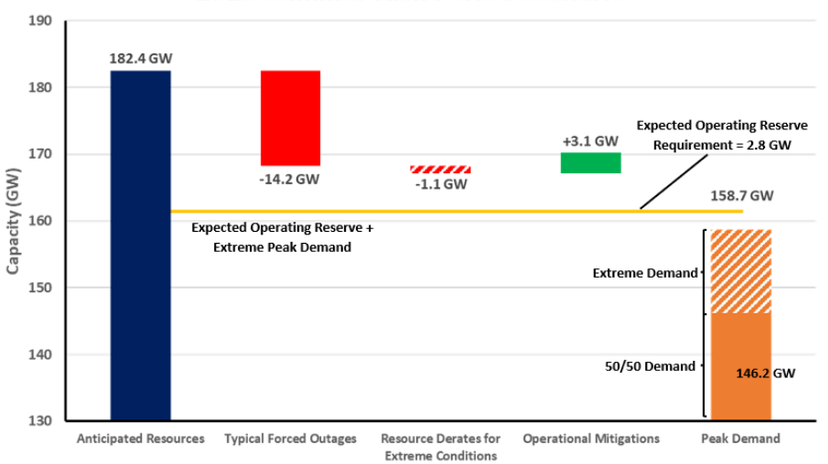
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



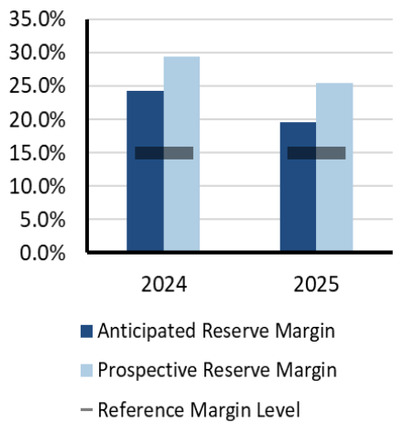
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

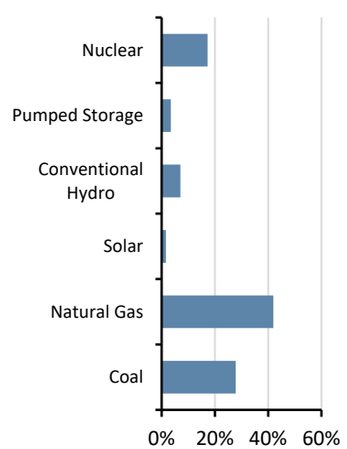
On-Peak Reserve Margin



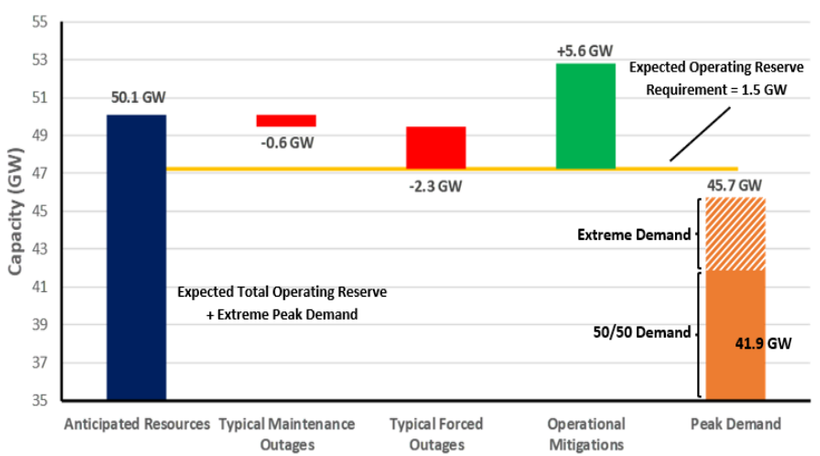
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



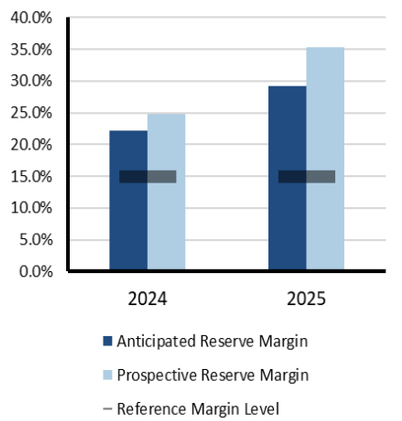
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

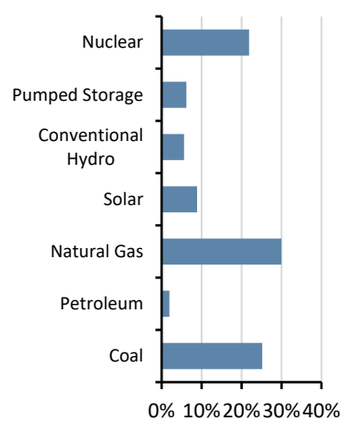
On-Peak Reserve Margin



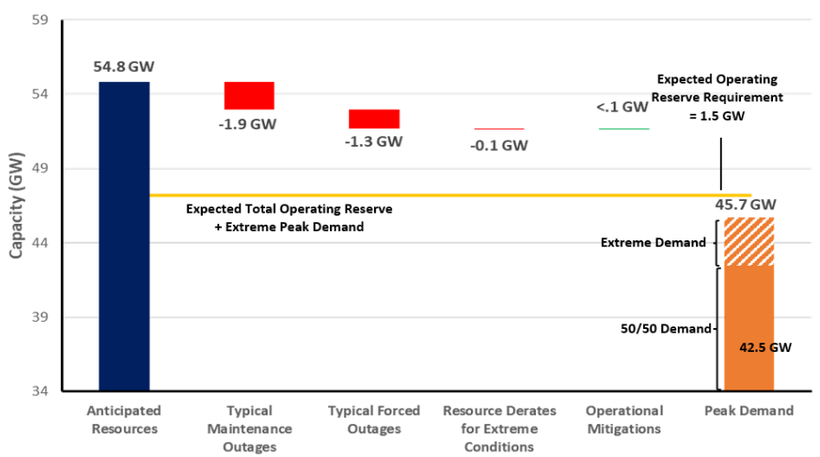
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures



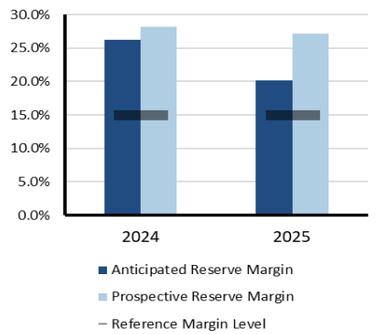
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

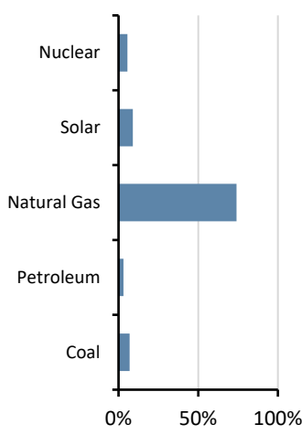
On-Peak Reserve Margin



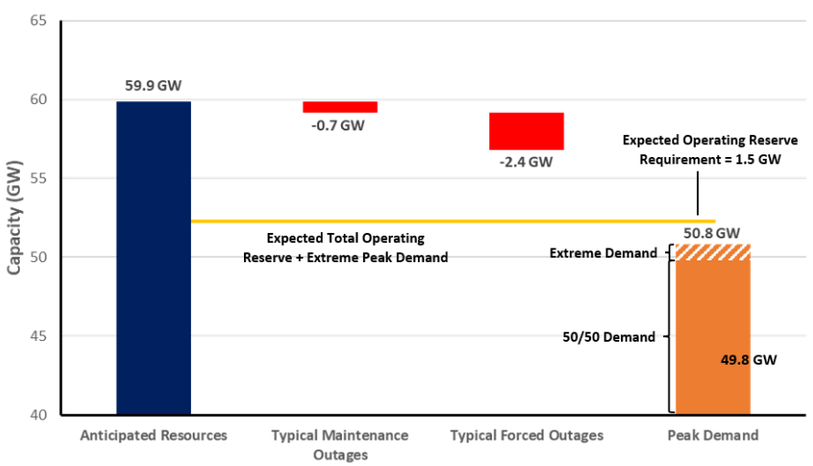
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



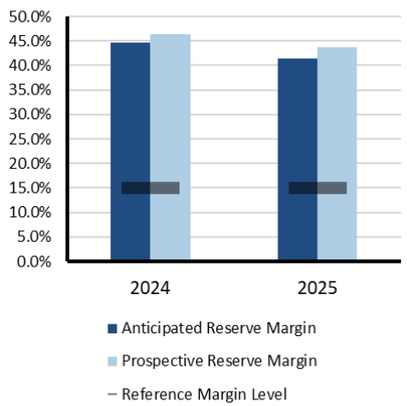
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

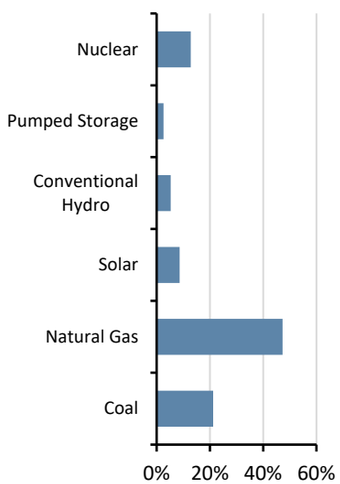
On-Peak Reserve Margin



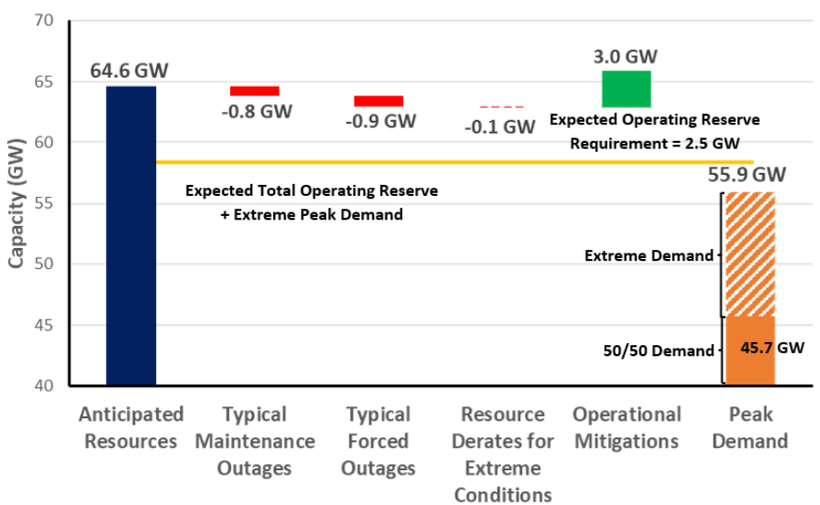
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

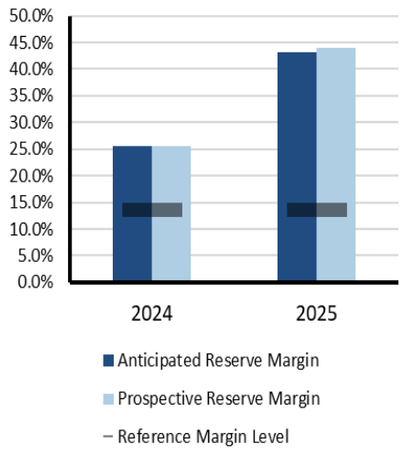
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

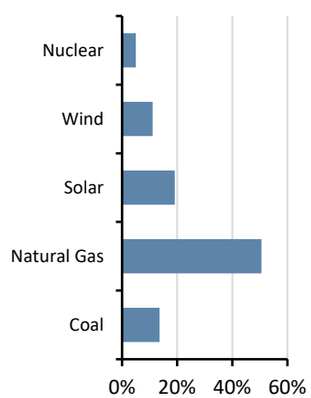
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

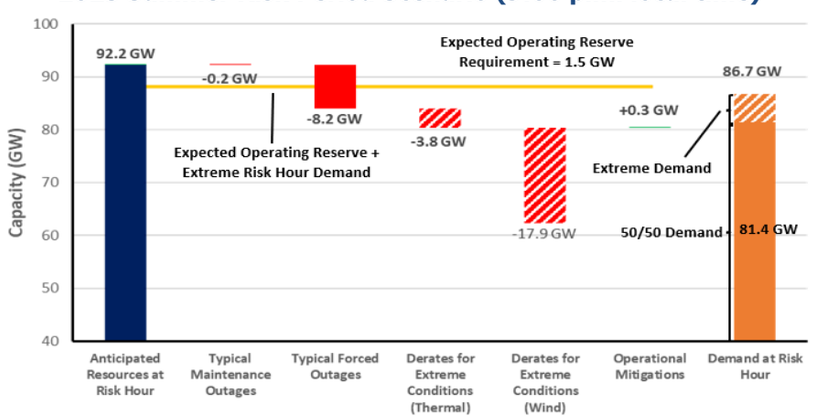
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

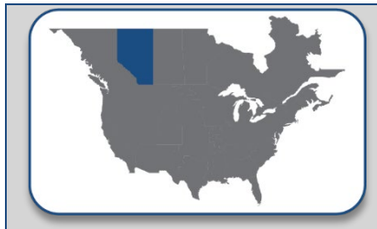
Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

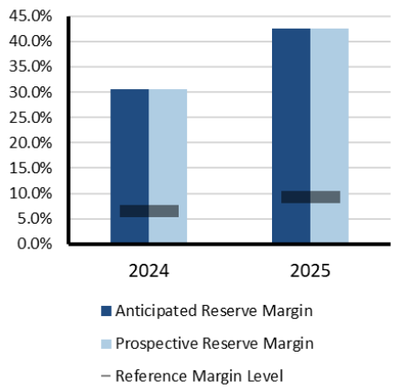
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

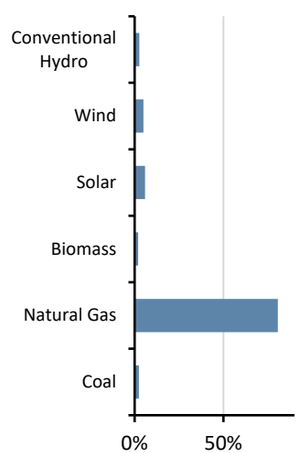
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

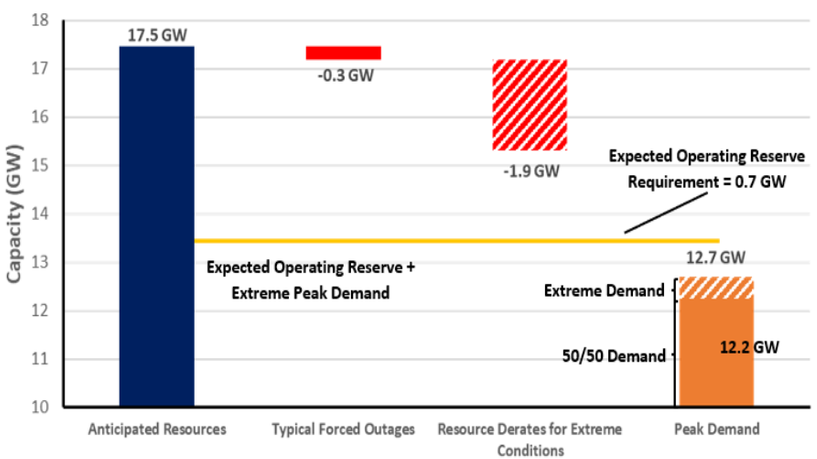
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

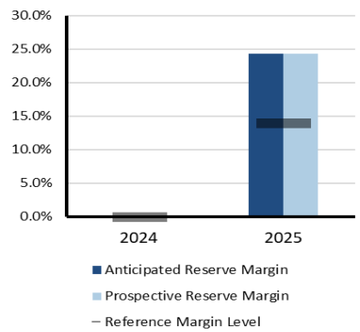
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

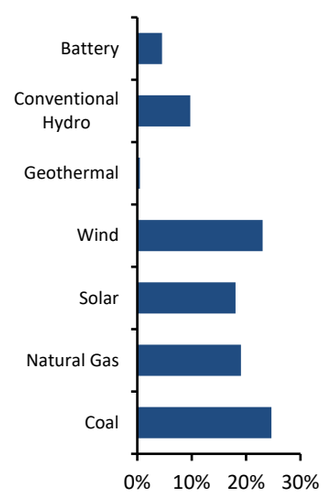
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

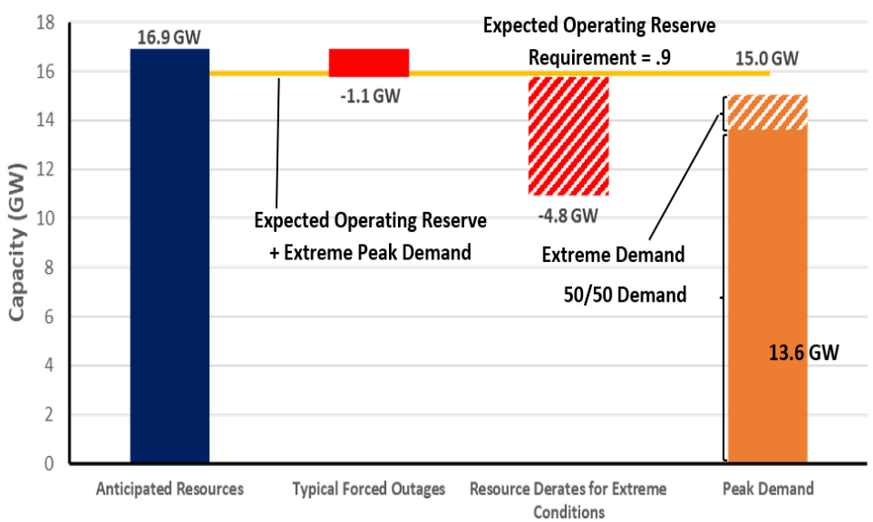
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

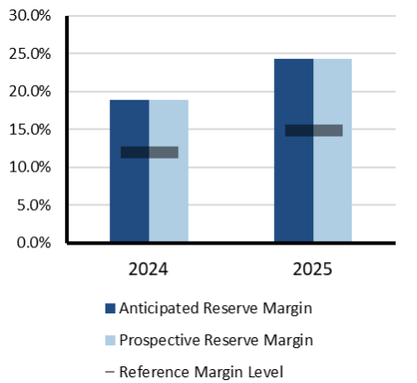
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

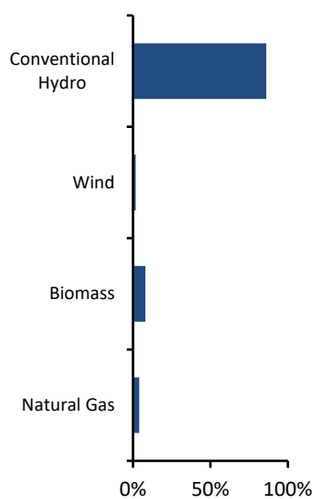
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

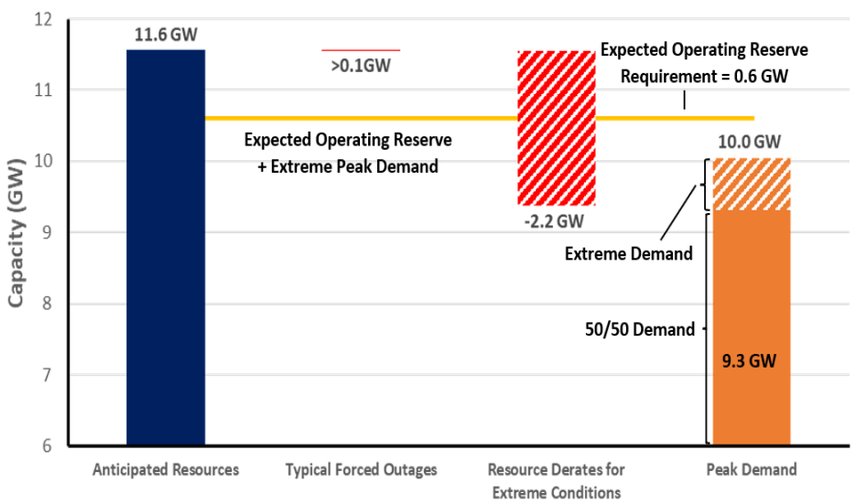
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA*.

Highlights

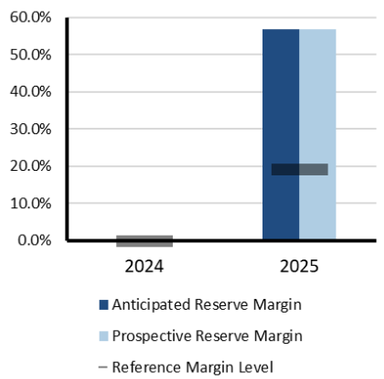
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

Risk Scenario Summary

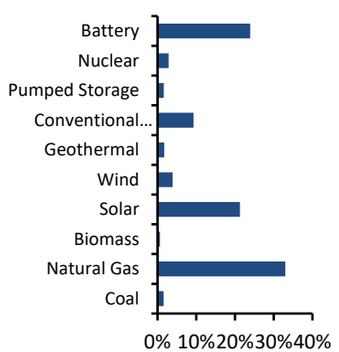
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

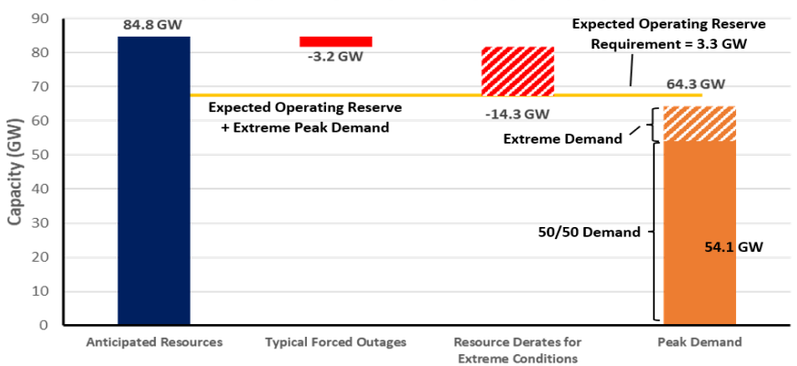
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

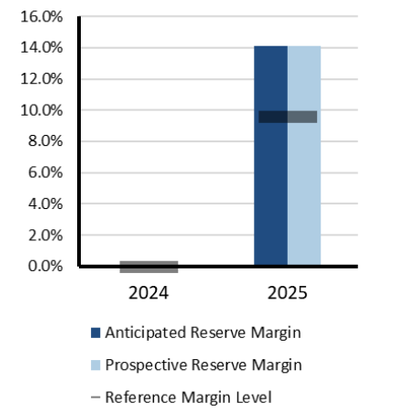
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

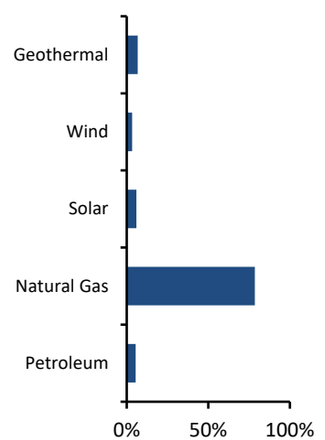
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

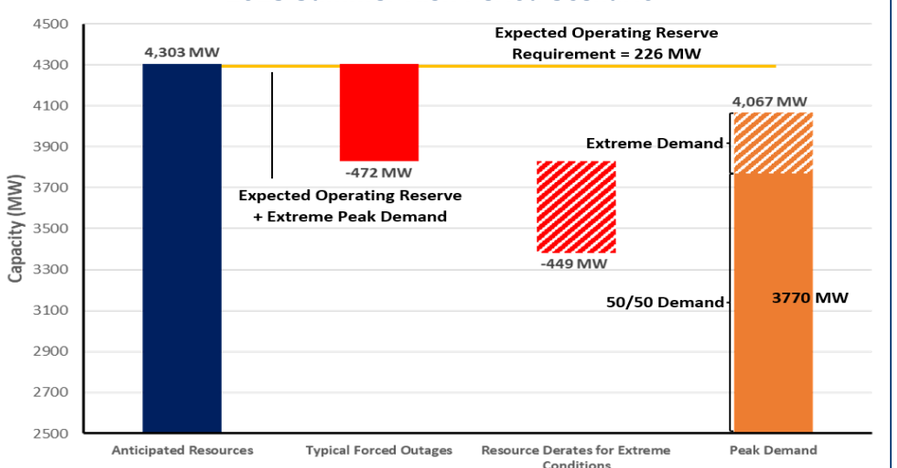
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

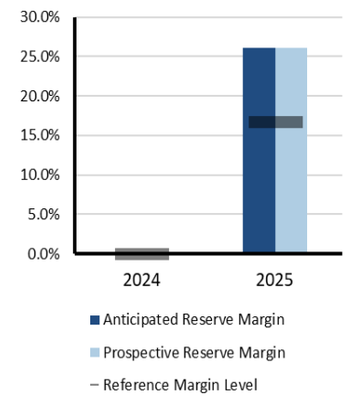
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

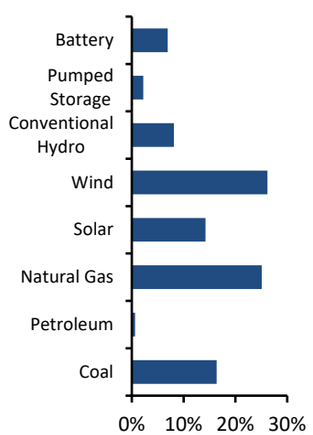
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

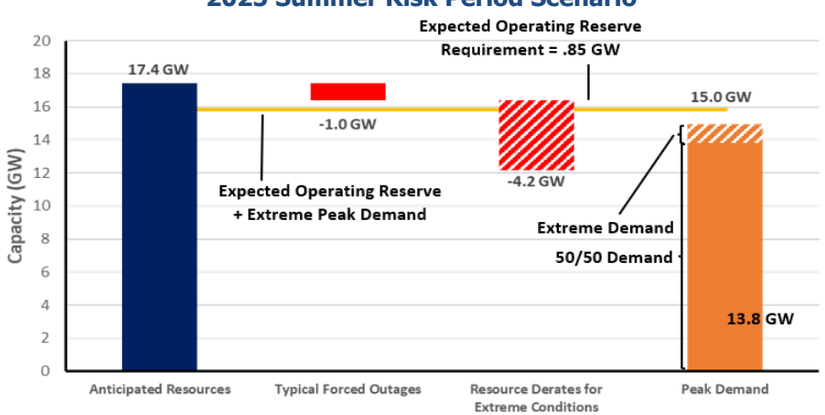


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

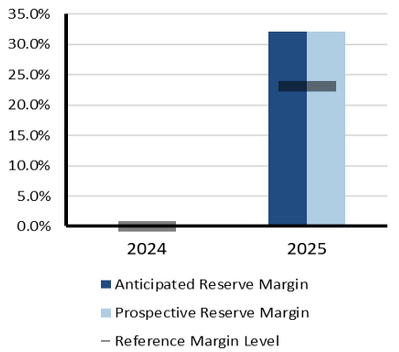
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

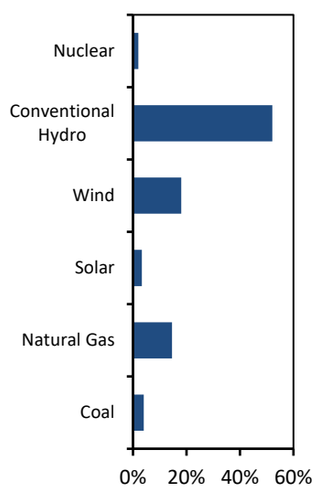
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

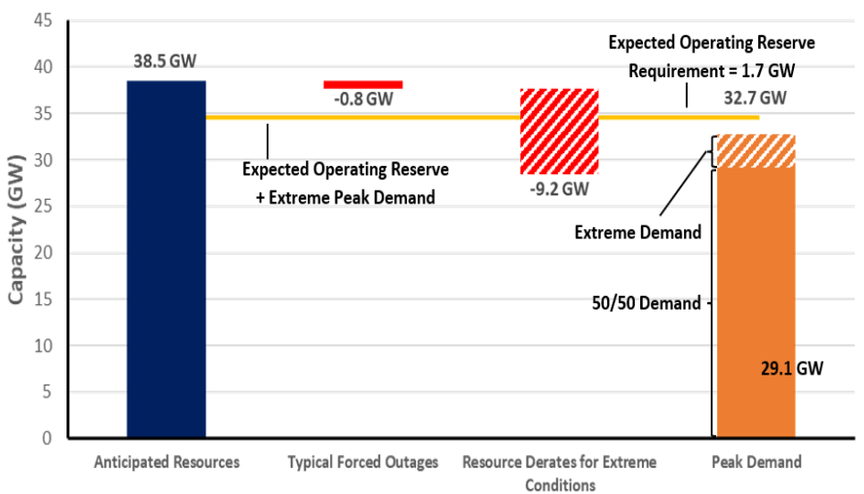
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



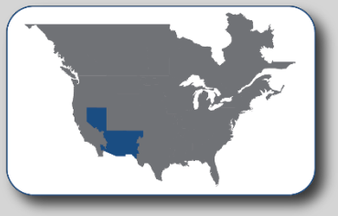
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

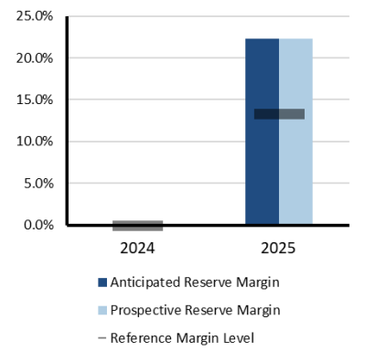
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

Risk Scenario Summary

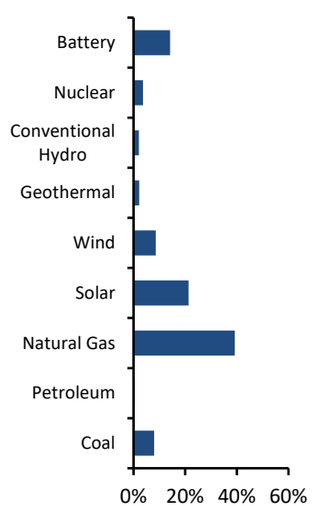
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

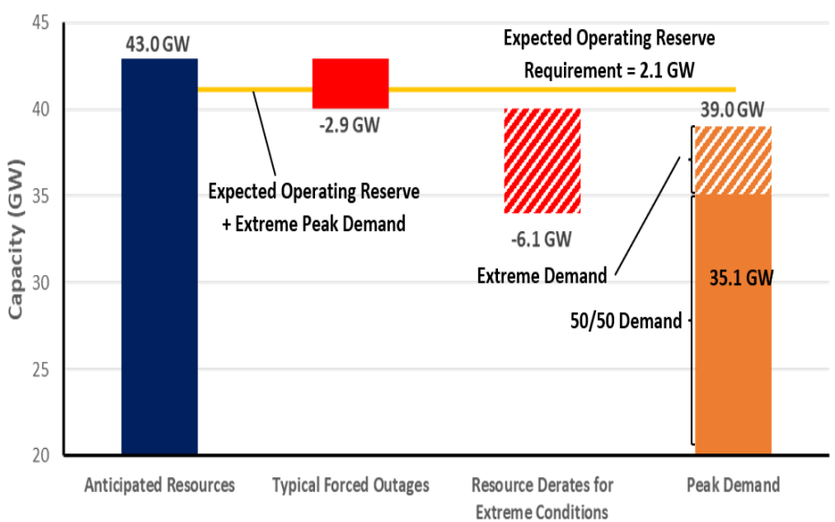
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

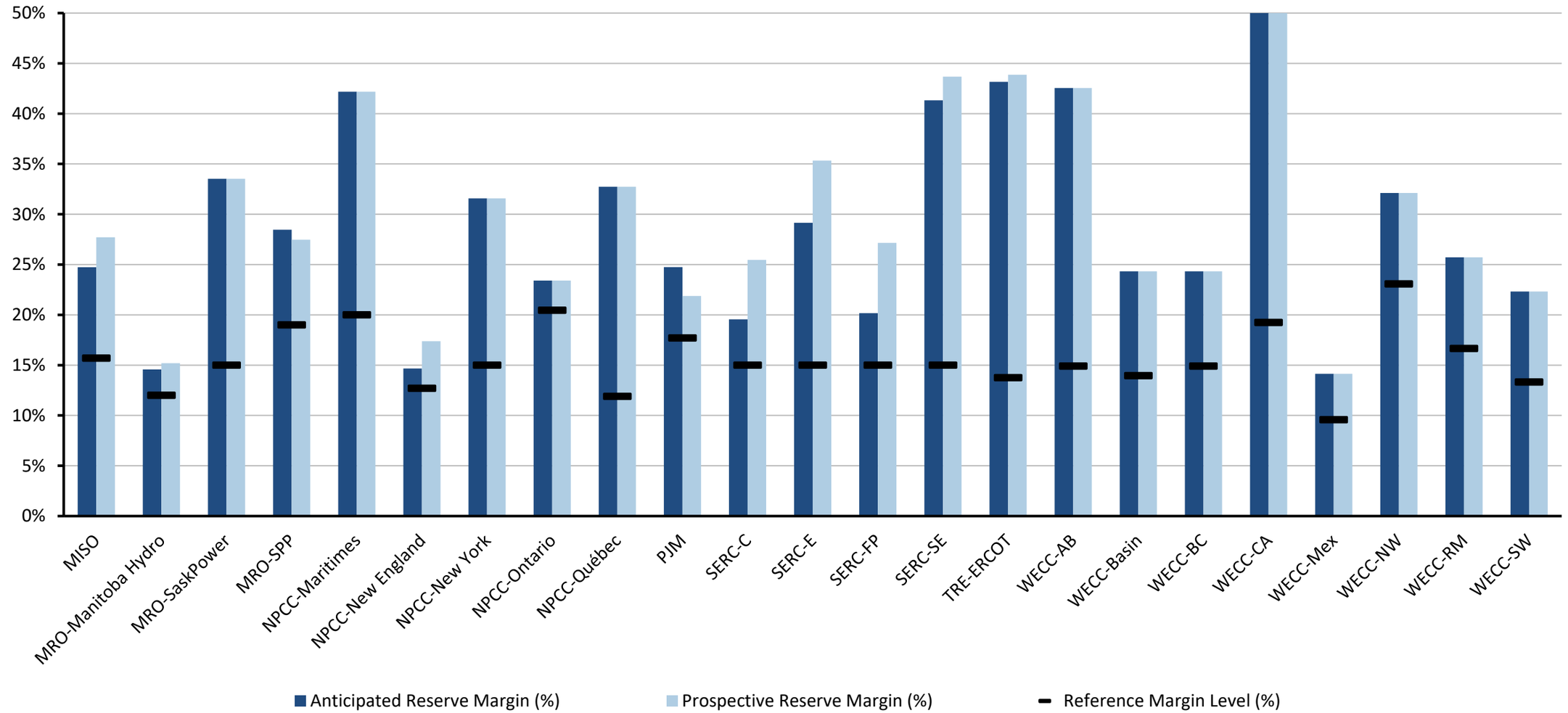


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

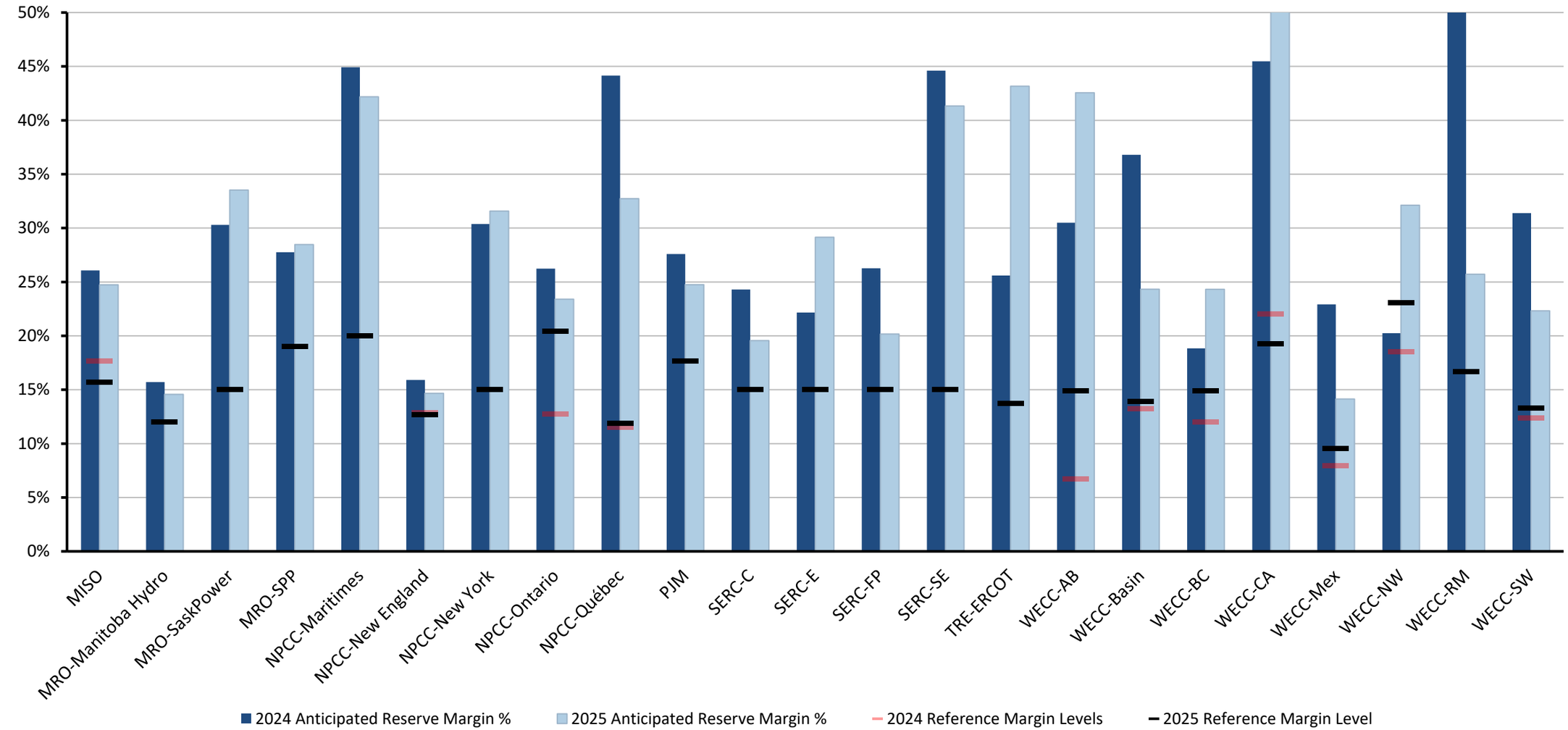


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

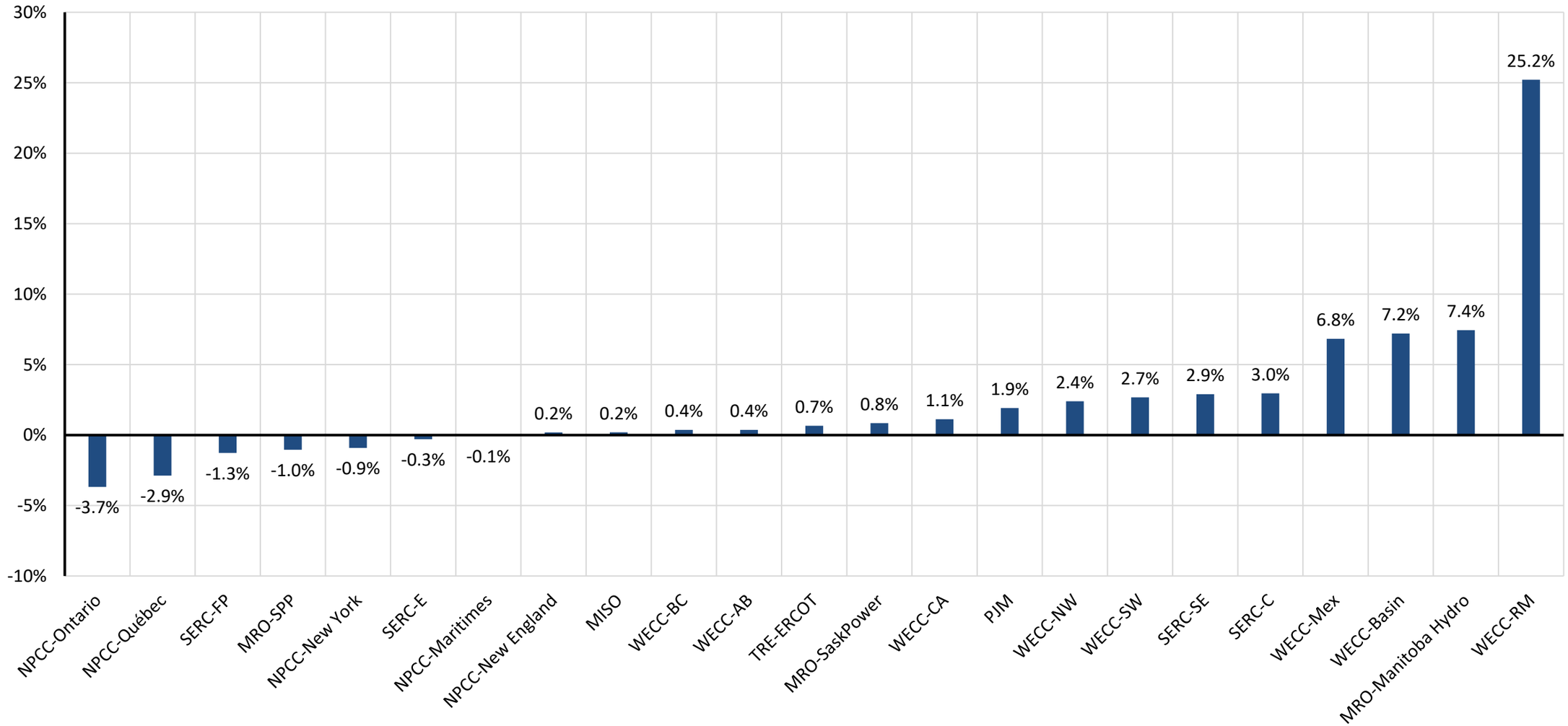


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

EXHIBIT 131-5

Review of NERC's 2025 Long-Term Reliability Assessment

Adria E. Brooks | June 22, 2026

Washington State Resource Adequacy Meeting

Full report can be found at https://gridstrategiesllc.com/reports/

Executive Summary

The NERC LTRA assesses future regional resource adequacy risk. Re-assessment using a more complete accounting of generation, imports, and demand from other data sources results in lower risk.

Overall, the LTRA resource margins are much tighter than what may occur for four reasons.

First, the LTRA underestimates likely-to-connect power resources. Power resources in advanced development stages are projected to provide enough capacity to resolve the majority of shortfalls identified in the LTRA.

Second, the most significant risk to resource adequacy shortfalls are delays to generator interconnection. Actions that delay interconnection study, permitting, and/or construction for generation facilities increase the likelihood of shortfalls.

Third, the LTRA underestimates imports from one region to another. At levels seen historically during extreme events, these are sufficient to further alleviate resource inadequacy.

Furthermore, additional interregional transmission would lessen shortfall risk. The NERC-identified interregional transfer capability additions would help resolve many of the identified seasonal capacity and energy shortfalls.

Fourth, data centers may require significantly less power than expected. Combined with the other three corrections, this scenario could allow all regions to meet 2030 peak summer load and reserve needs.

With a clearer vision of the future and rapid action, the grid could be even more reliable in five years than it is today.

NERC's 2025 Long-Term Reliability Assessment is too pessimistic. This analysis explores three major categories of input assumptions that impact the regional risks NERC identified.

North American Electric Reliability Corporation (NERC)'s Long-Term Reliability Assessment (LTRA) importantly captures potential reliability issues for a snapshot in time. NERC relies on utility-reported input data in making its assessments. This data, by definition, does not account for national power sector trends or limitations—such as double-counting of prospective demand or generation—that can have large impacts on future risk.

In this analysis we compare NERC's input data and assumptions against other sources to explore how changes to inputs impact the severity of risk identified in the LTRA. We explore three categories of inputs: demand, generation resources, and interregional transmission.

As the LTRA highlights, reserve margins—the difference between electricity demand and available supply—are tightening across the country. We find that while these margins are tightening, the severity of that risk is likely less than reported in the LTRA.

Three major factors:



Generation Resources



Interregional Transmission



Demand for electricity

GridStrategies

SOURCE | NERC "2025 Long-Term Reliability Assessment (LTRA)" (Jan. 2026)

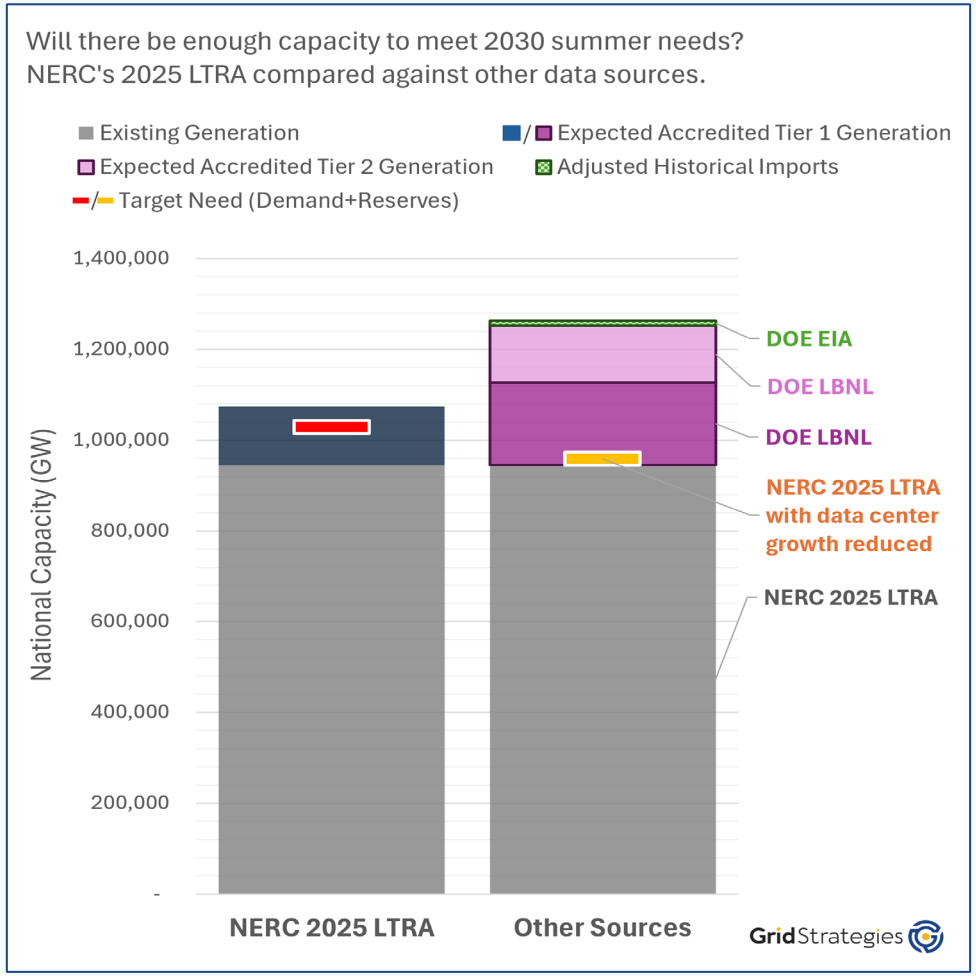
NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- The LTRA generation forecast is based on an incomplete accounting of nearly built generation projects. A more reasonable expectation for generation growth can be determined from each region's interconnection queue.
- The LTRA import forecast excludes the opportunity for increased imports from new interregional transfer capability.
- The LTRA demand forecast is supplied by utilities and regional planners. The vast majority of the load growth in the LTRA forecast is based on utility large load forecasts. Some of this load is uncommitted and may not materialize or it may curtail during peak periods.

The combination of low generation, low import, and high demand assumptions used in the 2025 LTRA resulted in resource margins appearing tighter than may actually materialize.

A comparison of the aggregated resource margins from NERC's LTRA and other national, reputable data sources, which account for the above three factors, is shown to the right.



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025; Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Historic Trends in NERC Assessment Data

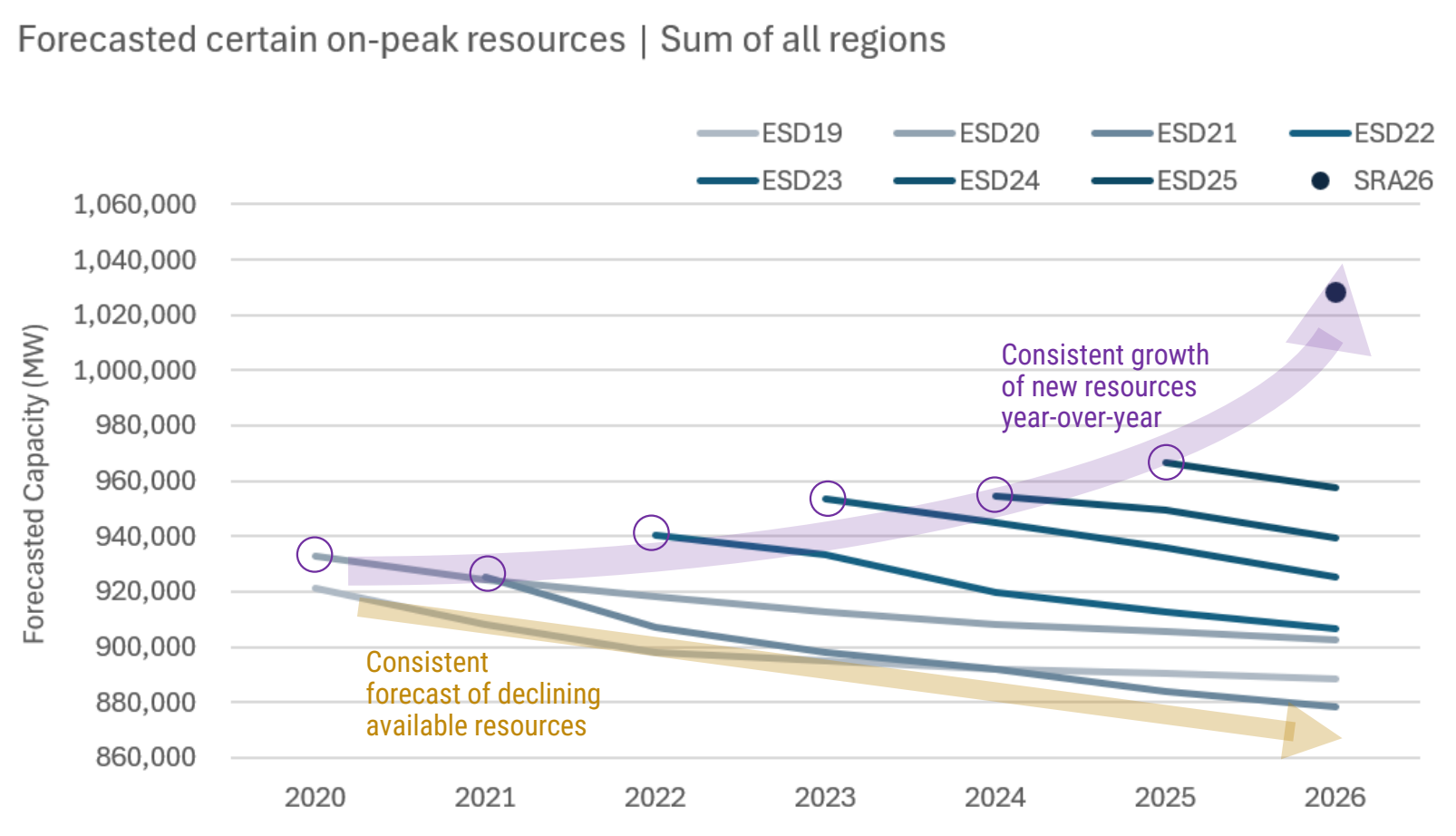
New analysis from our review of NERC's 2026 Summer Reliability Assessment, to be published in July.

New generation resources added to the grid continue to surpass NERC reliability assessment expectations year after year.

Each year NERC compiles regional planners' forecasts for new resources added to the grid. NERC's reliability assessments present both the existing generation corresponding to that year (starting point of any line on chart) and forecasted generation in future years.

NERC assessments have shown the same trend for the same last 7 years in a row: Resource capacity from new and existing generators are always forecasted to decline in future years, even though each subsequent assessment shows an increase in these resources.

The NERC assessments fail to capture the year-over-year growth of certain resources available to meet demand.



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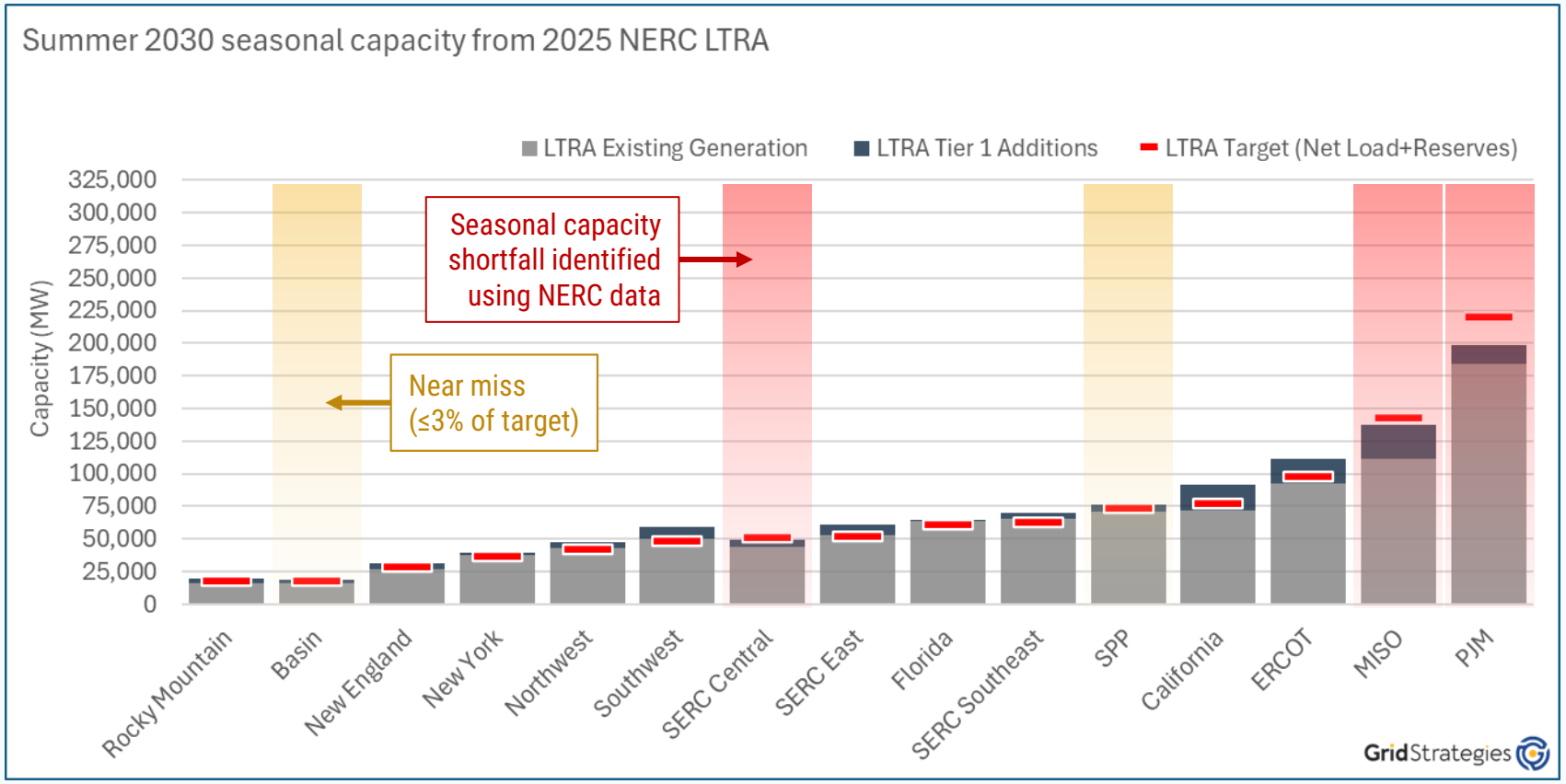
SOURCE | NERC, Electricity Supply and Demand Database (2025)

Regional RA Assessments for Summer 2030

NERC identified several regions as having elevated or high risk in their 2025 LTRA. This is partly due to only considering resources with executed interconnection agreements when determining shortfall risk.

All resources must undergo interconnection studies to identify any grid upgrades that may be necessary to reliably connect. At the end of the interconnection queue process, an interconnection agreement (IA) is executed. NERC considers any resource that has an executed IA as **Tier 1**.

To be resource adequate, a region must have enough future capacity and imports to meet load and reserve margins ("target"). NERC only counts Tier 1 resources toward future resources in the LTRA. NERC identifies three regions* that may be short of 2030 summer capacity needs using its assumptions. Two regions only exceed their target by less than 3%, marked here as "near miss" regions.



*NERC did not identify SERC Central as a heightened risk region though it is shown to be short of future capacity using the LTRA source data, perhaps because they did not identify elevated energy inadequacy risk despite the seasonal capacity shortfall in the region. We highlight it as elevated risk given the identified seasonal capacity shortfall.

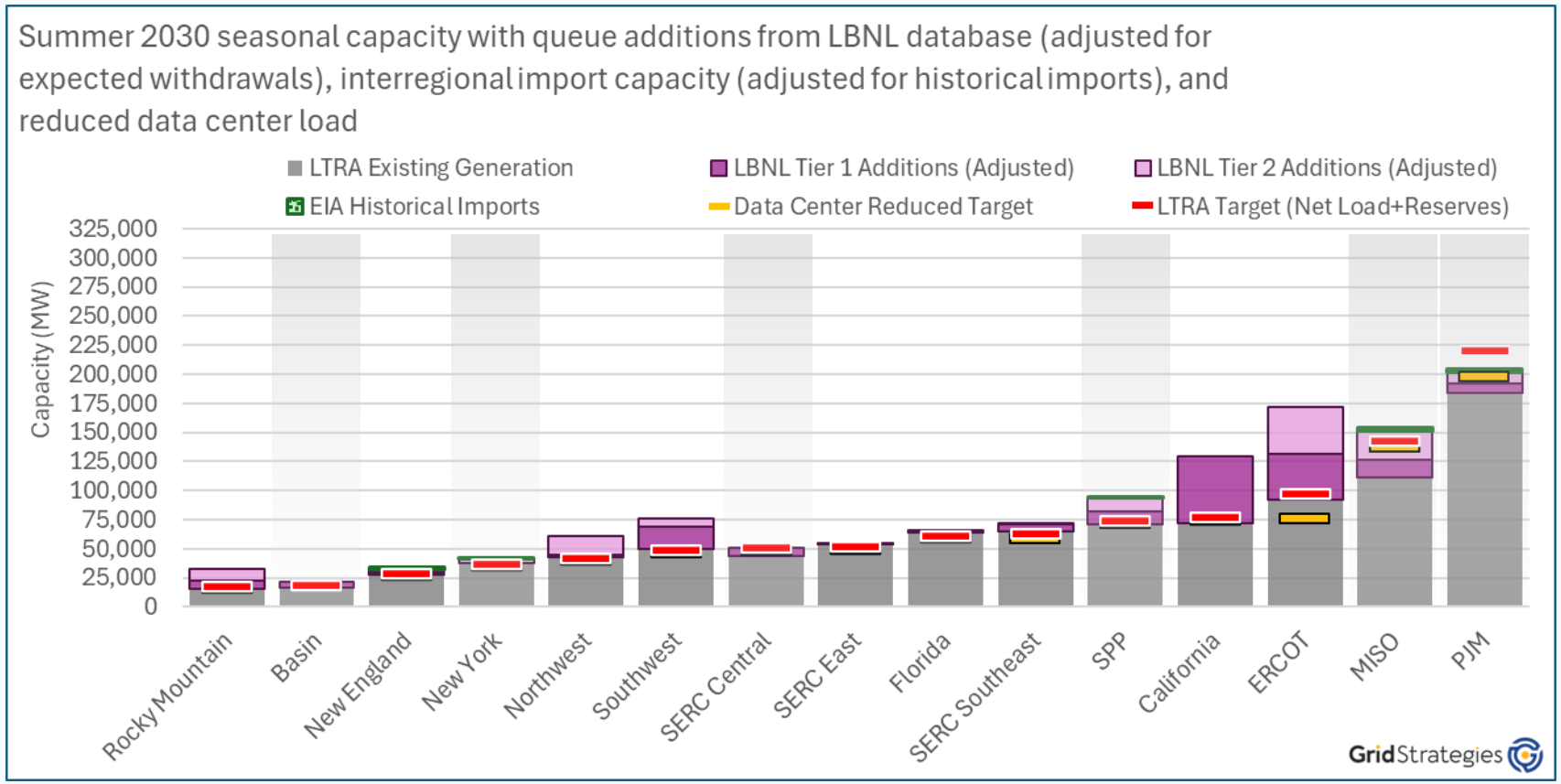
GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "2025 Electricity Supply & Demand (ES&D)" (Jan. 2026)

In this analysis, we considered different assumptions for generation resource, interregional transmission, and demand than the LTRA. The combination of all three suggest all regions could be resource adequate.

The regional seasonal resource adequacy risks identified in the 2025 NERC LTRA are all resolved when evaluated under different input assumptions:

- Including generation that is actively working through the interconnection queues in each region (Tiers 1 & 2)
- Discounting all generation nameplate capacity by the resource and region-specific accreditation methods
- Discounting generation queue data by historic regional and phase-specific withdraw rates
- Consideration of historic non-firm imports during extreme events
- Including increased interregional transfer capability capacity (albeit low likelihood of 2030 in-service date)
- Reduced data center load to account for microchip industry supply chain constraints and generation flexibility



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Shortfall Risk Should Still be Taken Seriously

While reduced risk is likely given different assumptions, these results should not be taken for granted. Enacting existing solutions is needed to stave off future reliability risk.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

EXHIBIT 131-6

Grid Strategies

Review of NERC's 2025 Long-Term Reliability Assessment

Adria E. Brooks, Michael Goggin, John D. Wilson

March 5, 2026

Prepared for Earthjustice, Natural Resource Defense Council, Sierra Club, and Environmental Defense Fund

Table of Contents

1. Executive Summary
2. Generation resource assumptions
3. Interregional transmission assumptions
4. Demand assumptions
5. Extreme event energy adequacy
6. Conclusions and solutions
7. Methodology

Executive Summary

The NERC LTRA assesses future regional resource adequacy risk. Re-assessment using a more complete accounting of generation, imports, and demand from other data sources results in lower risk.

Overall, the LTRA resource margins are much tighter than what may occur for four reasons.

First, the LTRA underestimates likely-to-connect power resources. Power resources in advanced development stages are projected to provide enough capacity to resolve the majority of shortfalls identified in the LTRA.

Second, the most significant risk to resource adequacy shortfalls are delays to generator interconnection. Actions that delay interconnection study, permitting, and/or construction for generation facilities increase the likelihood of shortfalls.

Third, the LTRA underestimates imports from one region to another. At levels seen historically during extreme events, these are sufficient to further alleviate resource inadequacy.

Furthermore, additional interregional transmission would lessen shortfall risk. The NERC-identified interregional transfer capability additions would help resolve many of the identified seasonal capacity and energy shortfalls.

Fourth, data centers may require significantly less power than expected. Combined with the other three corrections, this scenario could allow all regions to meet 2030 peak summer load and reserve needs.

With a clearer vision of the future and rapid action, the grid could be even more reliable in five years than it is today.

NERC's 2025 Long-Term Reliability Assessment is too pessimistic. This analysis explores three major categories of input assumptions that impact the regional risks NERC identified.

North American Electric Reliability Corporation (NERC)'s Long-Term Reliability Assessment (LTRA) importantly captures potential reliability issues for a snapshot in time. NERC relies on utility-reported input data in making its assessments. This data, by definition, does not account for national power sector trends or limitations—such as double-counting of prospective demand or generation—that can have large impacts on future risk.

In this analysis we compare NERC's input data and assumptions against other sources to explore how changes to inputs impact the severity of risk identified in the LTRA. We explore three categories of inputs: demand, generation resources, and interregional transmission.

As the LTRA highlights, reserve margins—the difference between electricity demand and available supply—are tightening across the country. We find that while these margins are tightening, the severity of that risk is likely less than reported in the LTRA.

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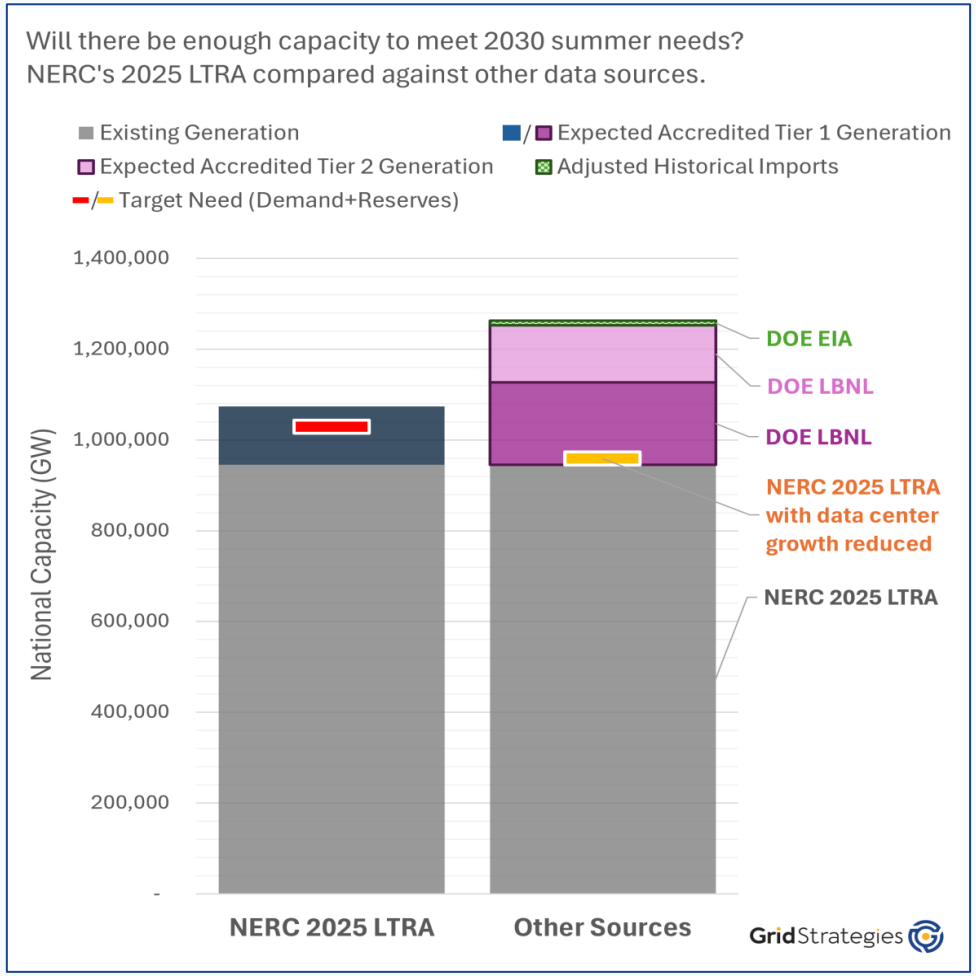
NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

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- The LTRA generation forecast is based on an incomplete accounting of nearly built generation projects. A more reasonable expectation for generation growth can be determined from each region's interconnection queue.
- The LTRA import forecast excludes the opportunity for increased imports from new interregional transfer capability.
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The combination of low generation, low import, and high demand assumptions used in the 2025 LTRA resulted in resource margins appearing tighter than may actually materialize.

A comparison of the aggregated resource margins from NERC's LTRA and other national, reputable data sources, which account for the above three factors, is shown to the right. This chart is explained in the Methodology.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025; Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Implementing currently available solutions will help all regions alleviate the identified capacity and energy risks.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

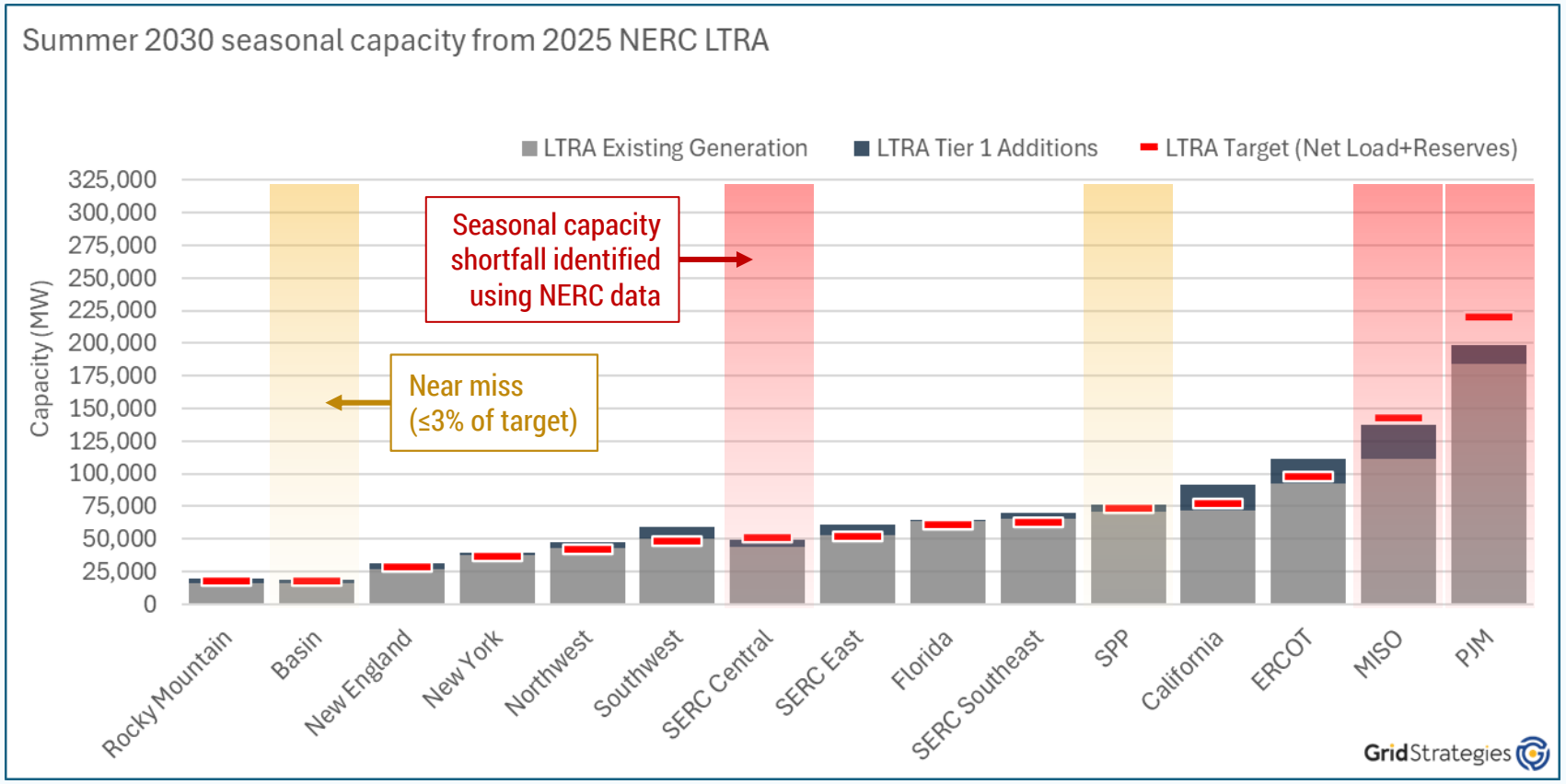
- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Generation Resource Assumptions

NERC only considered resources with executed interconnection agreements when determining shortfall risk.

All resources must undergo interconnection studies to identify any grid upgrades that may be necessary to reliably connect. At the end of the interconnection queue process, an interconnection agreement (IA) is executed. NERC considers any resource that has an executed IA as **Tier 1**.

To be resource adequate, a region must have enough future capacity and imports to meet load and reserve margins ("target"). NERC only counts Tier 1 resources toward future resources in the LTRA. NERC identifies three regions* that may be short of 2030 summer capacity needs using its assumptions. Two regions only exceed their target by less than 3%, marked here as "near miss" regions.



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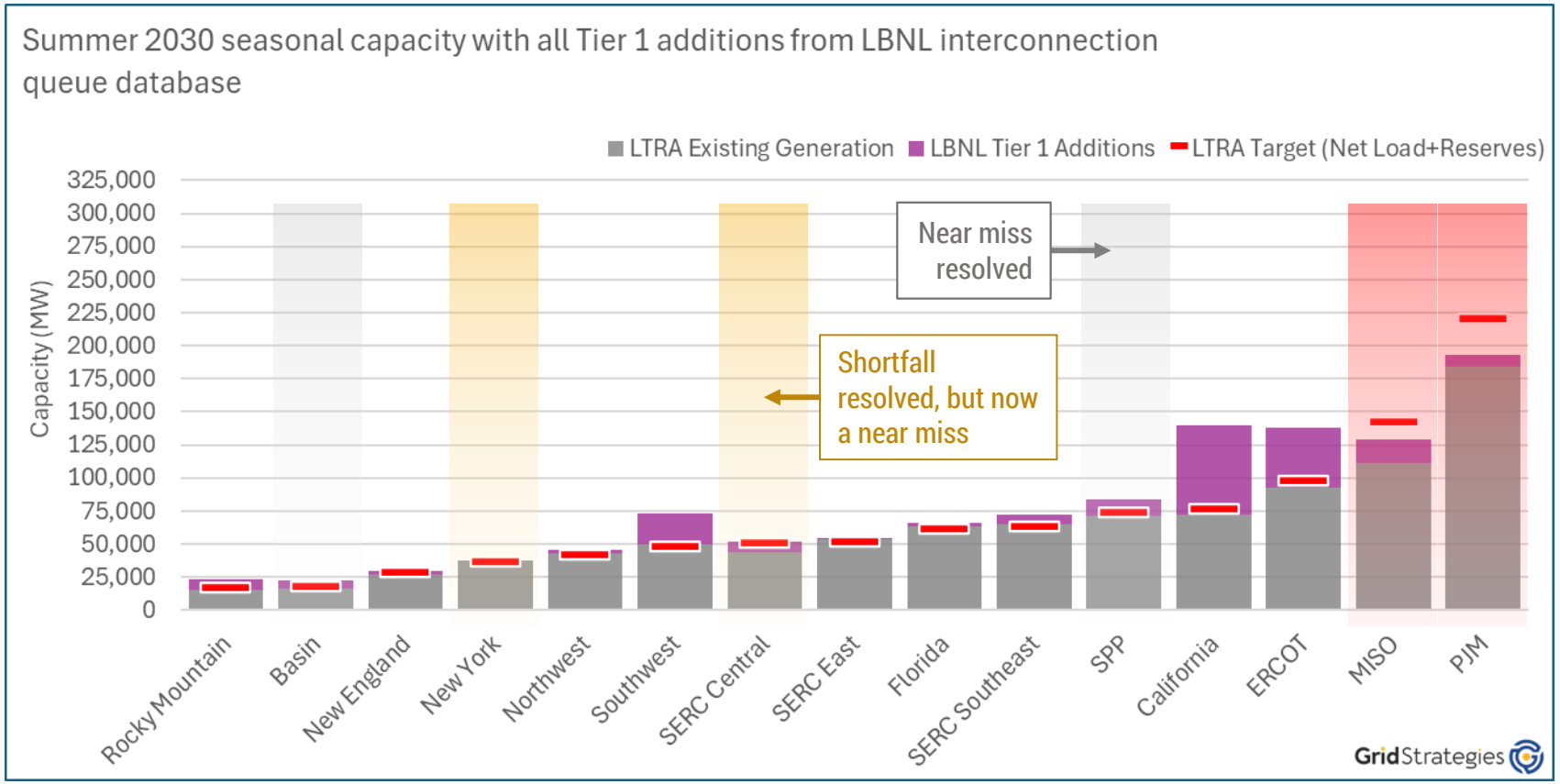
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SOURCE | NERC "2025 LTRA" (2026); NERC "2025 Electricity Supply & Demand (ES&D)" (Jan. 2026)

The amount of resource capacity with executed interconnection agreements in the LTRA is lower than that compiled by LBNL.

The U.S. Department of Energy (DOE)'s Lawrence Berkley National Laboratory (LBNL) tracks interconnection queue data across all regions and is a reputable source of high-quality data. The LBNL data suggests more accredited **Tier 1** resource capacity is available nationwide than is recorded in the LTRA, though regional allocations vary. The mismatch in data could be due to different processing methods, collection periods, and, importantly, resource accreditation methods.*

Using the LBNL data paints a different future risk picture than the LTRA—only two regions show 2030 summer shortfalls. This highlights how sensitive risk assessments are to their input data.



*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. Utilities do not uniformly report seasonal or resource-specific accredited capacity to NERC for use in the LTRA, which, as NERC highlights, may inaccurately account for the capacity availability during peak load (LTRA at 9, 44, 60, 71, 76, 122). See the Methodology for more information.

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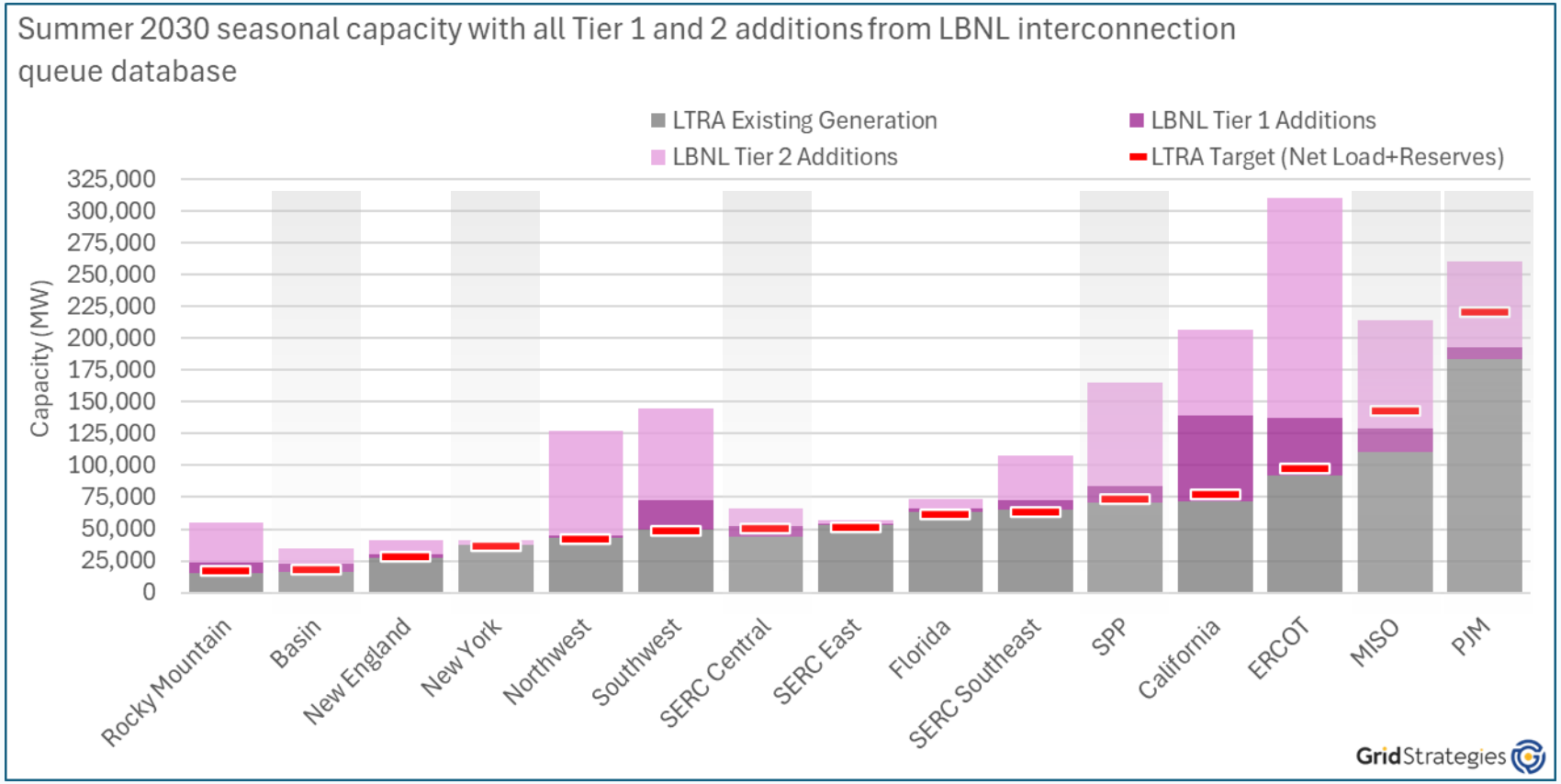
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (Aug. 2025)

There are more resources under development in each region than those with executed IAs. Providing a path to interconnection for these resources helps alleviate risk.

NERC considers any resource that has begun system studies, but has not yet completed them, to be a **Tier 2** resource. According to LBNL data, there is nearly five times the accredited Tier 2 resource capacity with planned in-service dates by 2030 nationwide than NERC-counted Tier 1 as well as three times the NERC-counted Tier 2 summer 2030 resource capacity.

NERC does not include any Tier 2 capacity in the LTRA shortfall analysis. Inclusion of this capacity suggests that regions could be at less risk of seasonal shortfalls than illustrated in the LTRA.

But this is only true if there are clear pathways for interconnection of these resources. LBNL research shows that generators are facing increasing delays in the interconnection study and post-study phases. These delays contribute to project cancellations, which is dangerous for seasonal resource adequacy.



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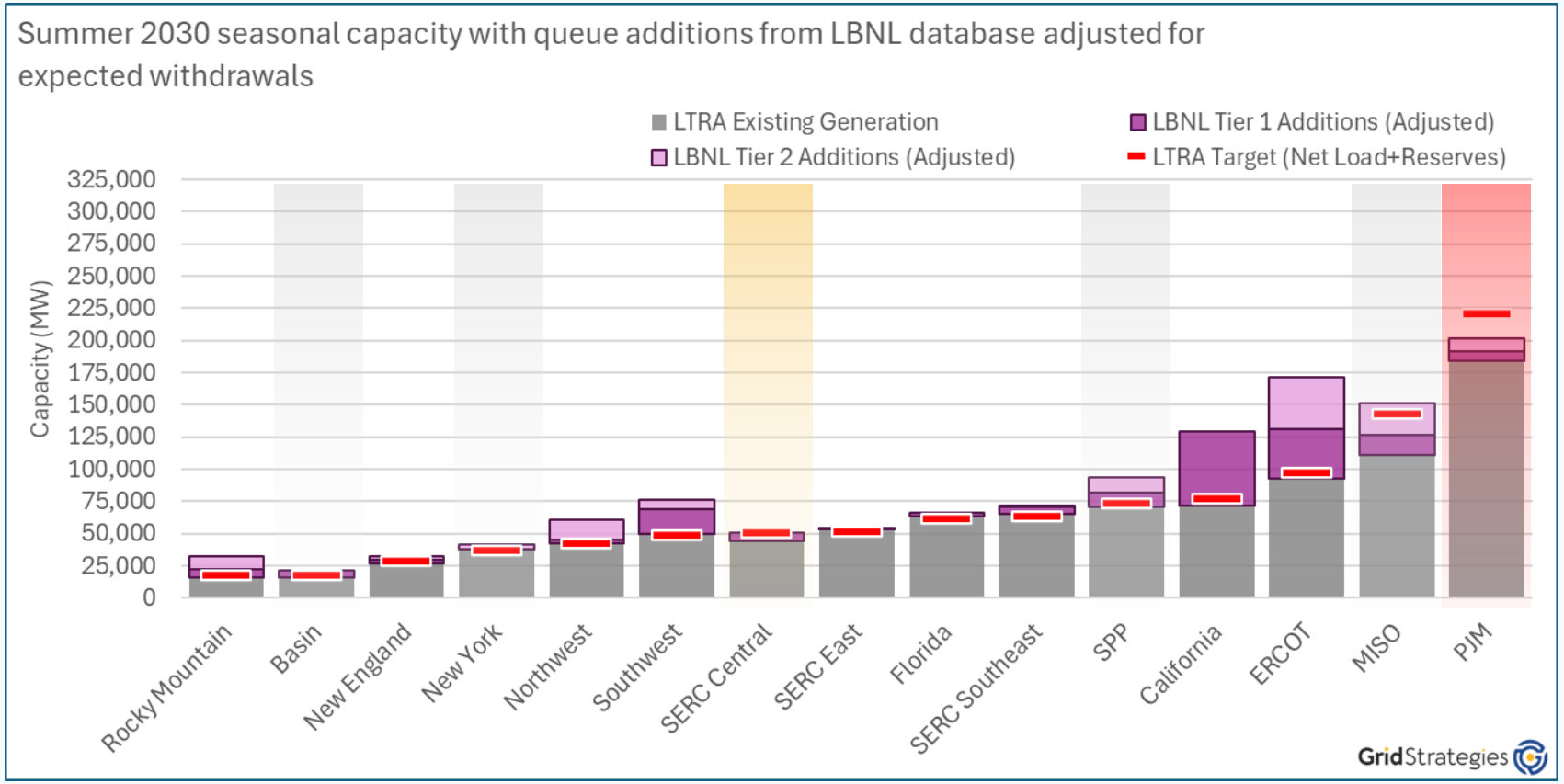
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Even when accounting for likely resource cancellations in the queue and post-queue phases, LBNL data suggests enough resources could connect to meet most regions' 2030 capacity needs.

It is unlikely that all Tier 1 and Tier 2 resources will connect to the grid. LBNL analysis shows as much as 85% of resources that enter the queues fails to connect to the grid ("withdrawal rates"), including facilities with executed IAs.

Rather than omit all Tier 2 data to account for the risk of cancellations (as done in the LTRA), we apply historic region-specific and phase-specific withdrawal rates to the LBNL data to estimate how much may connect to the grid by 2030.

Consideration of likely-to-connect resources currently in the interconnection queues resolves the majority of identified seasonal adequacy shortfalls. The resolution of shortfalls shown here is accomplished without a delay to announced resource retirements.



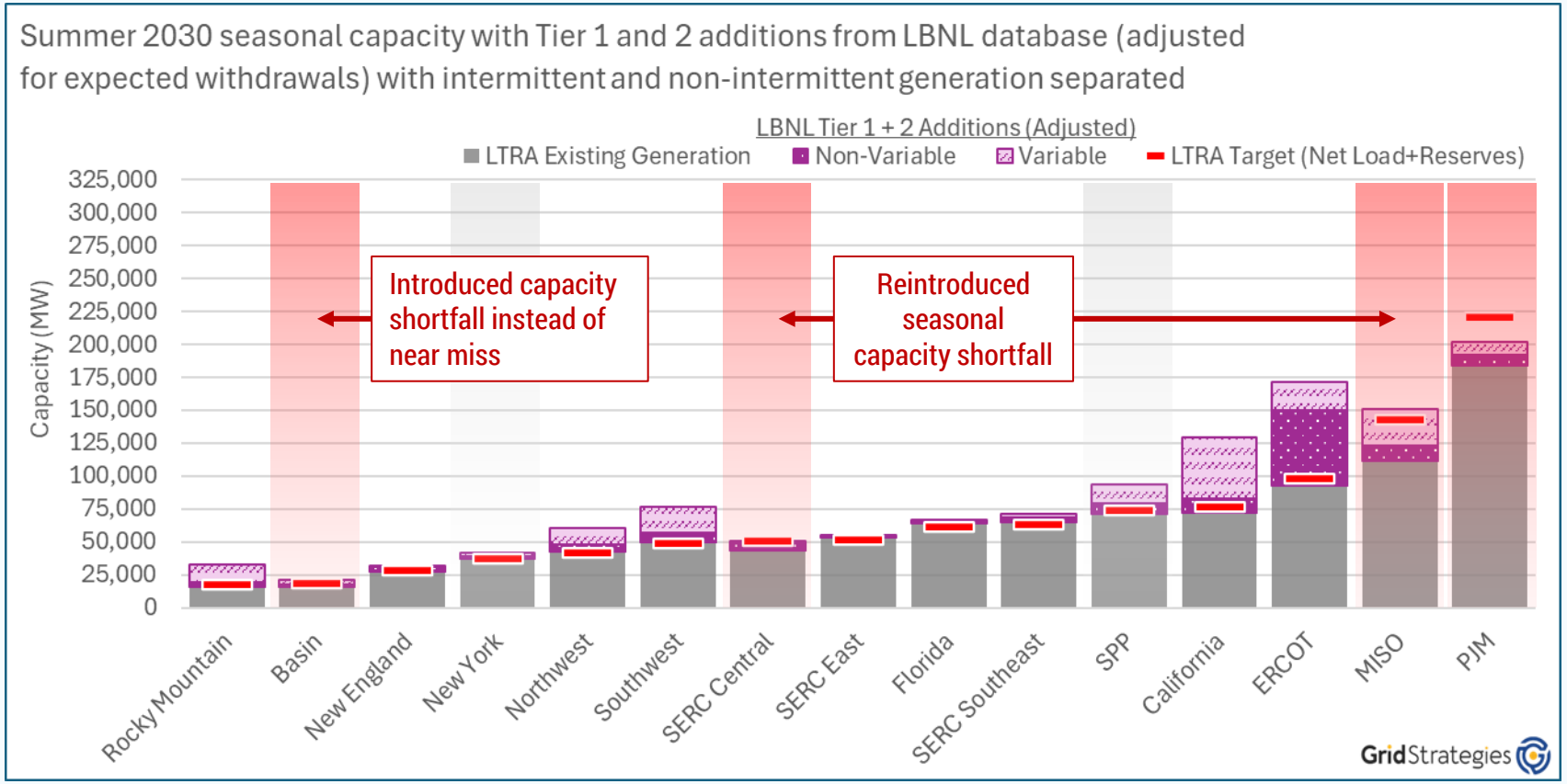
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Delays in the study, permitting, and/or construction phases to resources already in the queues—including wind and solar facilities—could jeopardize meeting regional seasonal capacity needs.

Additional permitting or equipment procurement steps applied to facilities increases their time to interconnection or results in project cancellation outright. Unnecessary hurdles for facilities waiting to interconnect could jeopardize huge amounts of resource capacity in advanced stages of development.

Shown here is the amount of likely-to-connect Tier 1 and 2 resource capacity from the LBNL data, broken out into variable (wind and solar) and non-variable resources.

Actions which delay permitting or construction for variable generation facilities could prevent large portions of the Midwestern, Southeastern, and Western regions from maintaining resource adequacy where they otherwise would be able to.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

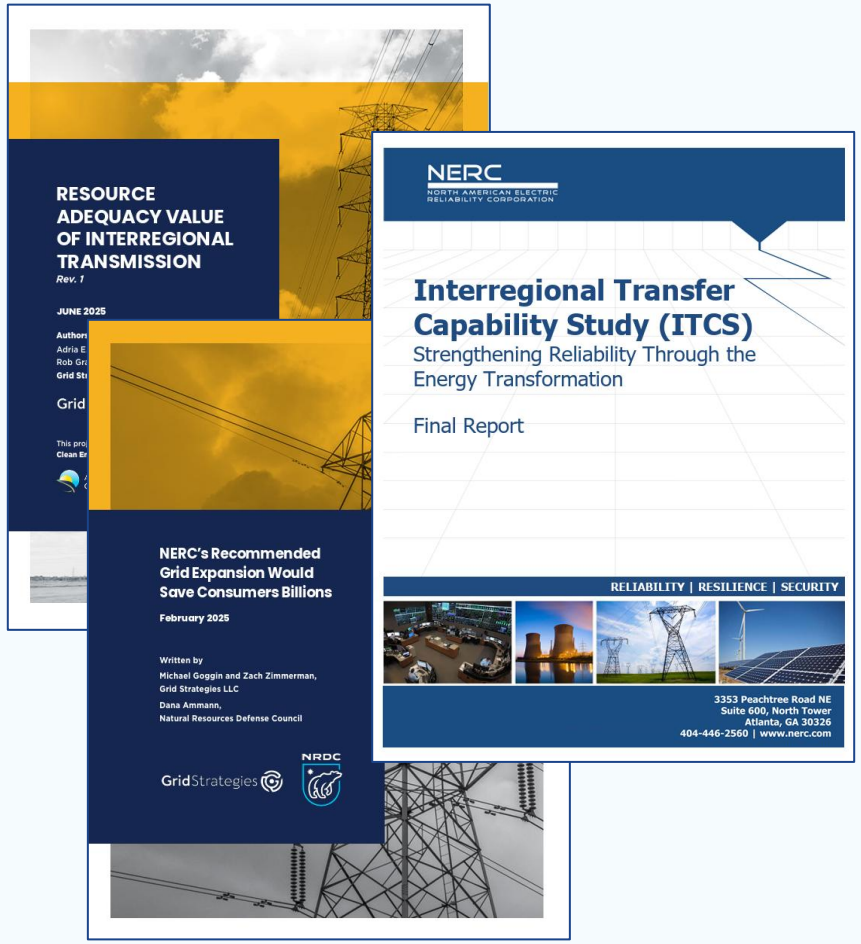
Interregional Transmission Assumptions

Interregional transmission helps to alleviate capacity adequacy concerns, especially during times of grid stress.

One of the many benefits of interregional transmission is the ability to move power between regions during times of grid stress. The availability of imports is primarily due to net load diversity among regions due to timing differences in peak demand and generation unavailability, particularly during severe weather events. Weather patterns and extreme grid events do not impact all regions equally, so there is often spare capacity in a neighboring region that could be shared during times of need. As a result, this benefit will largely persist even if reserve margins in neighboring regions are lower going forward. This phenomenon is well documented in several studies.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores the historical role of "non-firm" imports, which are available during extreme events. For example, MISO imported over 13 GW during Winter Storm Uri, of which 5 GW was in turn exported to SPP, imports that literally kept the lights on in those regions.

Sharing of power can only occur, of course, if enough interregional transmission exists to move the available power. NERC acknowledged this in their 2024 Interregional Transfer Capability Study (ITCS) where they measured the amount of interregional transmission capacity that should be added to each region to help support energy adequacy. The ITCS analysis looks at peak grid stress days for each region and determines if excess capacity is likely to be available in neighboring regions during those same hours. It then suggests interregional transmission capacity be added to move that excess generation.



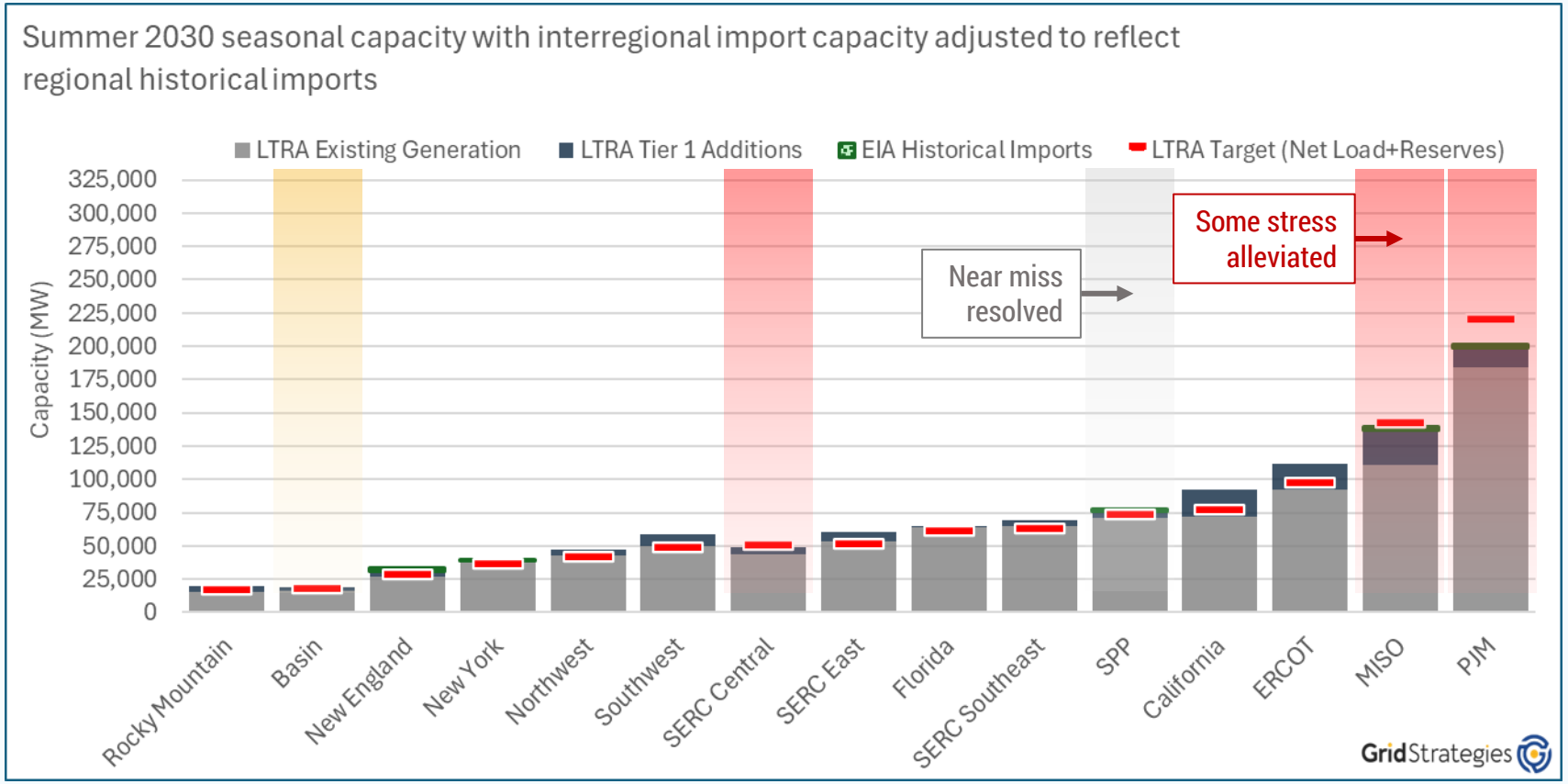
Source | NERC "Interregional Transfer Capability Study" (2024); Goggin, M., Zimmerman, Z., Amman, D., "NERC's Recommended Grid Expansion would Save Consumers Billions" (2025); Brooks, A., Silverstein, A., Gramlich, R., "The Resource Adequacy Value of Interregional Transmission" (2025)

The LTRA only counts firm imports, omitting non-firm imports. Some regional stress is alleviated when combining the LTRA capacity assumptions with historical non-firm import availability.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores non-firm imports over interregional transmission lines that have been available during historical grid stress events.

Hourly regional import and export data collected by the U.S. Energy Information Administration (EIA) confirm regions import significantly more during periods of peak demand than the LTRA assumes.

The inclusion of non-firm imports that are historically available during extreme events helps further alleviate resource inadequacy.



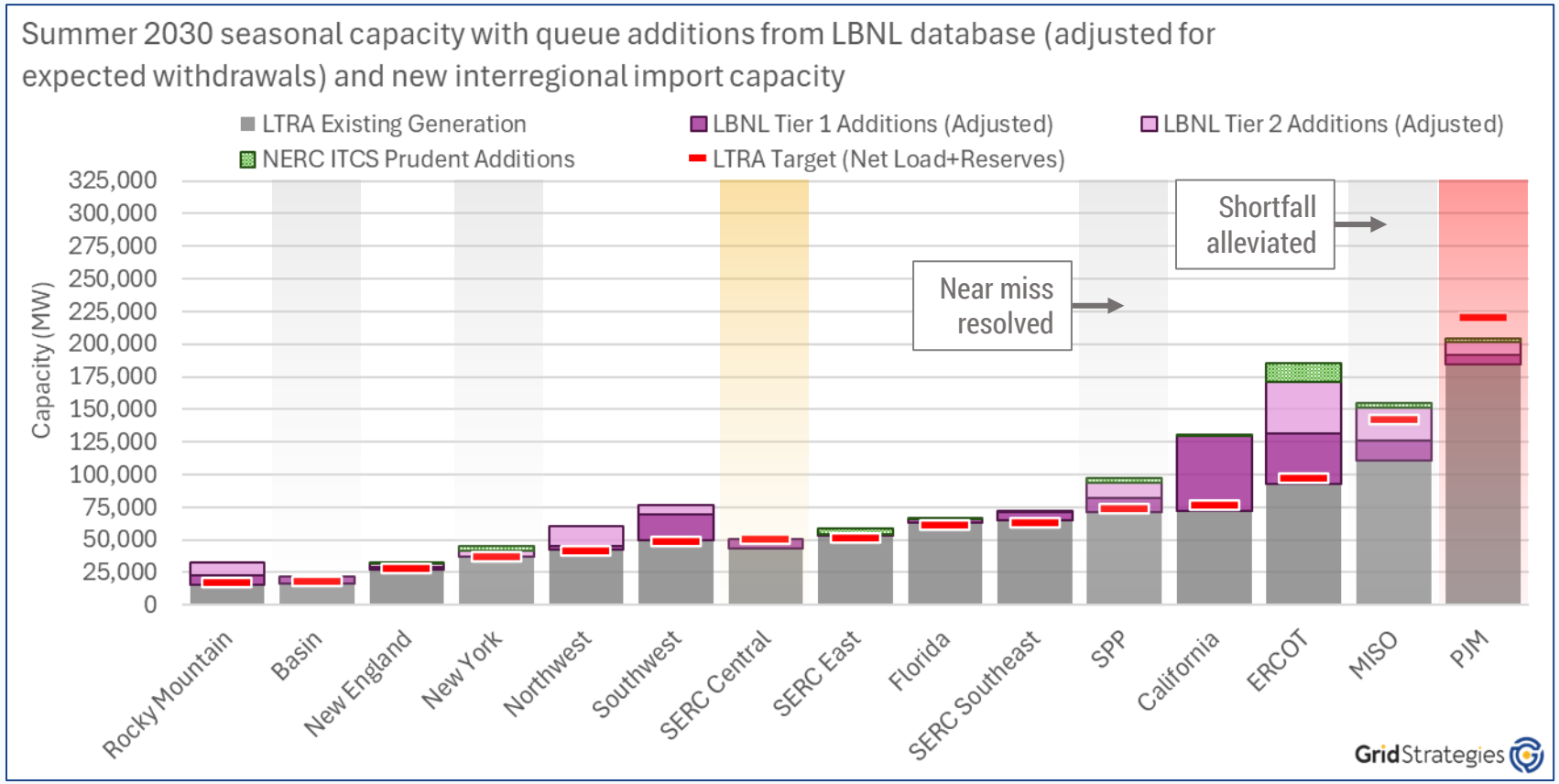
SOURCE | NERC "LTRA" (Jan. 2026); NERC "ES&D" (Jan. 2026); U.S. EIA "About the EIA-930 data" (accessed Feb. 2026)

The combination of NERC-identified increased transfer capability and reasonable resource assumptions from the interconnection queues provides even more security to avoid shortfalls.

The combination of interregional transmission additions suggested by NERC's ITCS and reasonable generation additions using LBNL queue data would provide regions with additional capacity to weather seasonal grid stress events.

The addition of new NERC-identified transfer capability would likely resolve many of the identified seasonal capacity and energy shortfalls.

All transmission takes a long time to develop, but this is especially true for interregional transmission. Unfortunately, the NERC-identified interregional transfer capability additions are unlikely to be built by 2030 under the status quo. Legislative and regulatory action taken now could accelerate the construction of these prudent additions.



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SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Demand Assumptions

The load growth in the LTRA is based on utility projections that, in some cases, are based on overstated assumptions.

NERC compiled the LTRA load growth forecast by rolling up projections from utilities and regional grid operators. Large load forecasts are uncertain and could overstate load growth for several reasons.

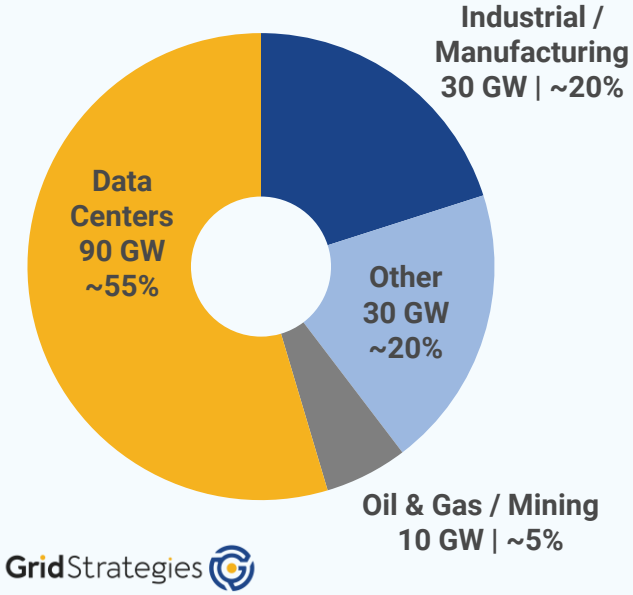
Reliance on customer data: Large load forecasts rely primarily on customer-supplied information.

- Data centers, in particular, are constrained by global supply chains. There is no clear method for individual load forecasts to account for how supply chain constraints will affect specific projects.
- Load forecasts lack visibility into customers' overall business plans. There may be "double counting" as data center operators develop more sites as options than they intend to build. The LTRA includes all loads with "development commitments necessary to drive grid planning studies." In contrast, the LTRA only counts generators that have completed all planning studies and signed an interconnection agreement.
- Many regulated utilities have an incentive to overstate load growth and interconnection success rates to justify additional rate-based investments in generation and other infrastructure.

Time lags: Producing and compiling load growth projections occurs months before the LTRA is released. Mounting delays in large load interconnection and policy changes appear to have slowed load growth since their compilation.

- Load interconnection queue backlogs and long lead times for power transformers and circuit breakers needed for interconnection are likely to delay commercial operation of many large load projects.
- As outlined in the following slides, new large loads from data centers, cryptocurrency mining, and hydrogen electrolysis could each face headwinds that are not fully accounted for in the LTRA.
- Recent policy changes are reducing load growth, such as the recent termination or restriction of federal tax credits for electric vehicles, heat pumps, hydrogen electrolysis, and advanced manufacturing.

Drivers of Load Growth (2025 – 2030)



Load flexibility: Regulations and utility tariffs are beginning to require some large loads to provide demand response or backup generation during periods of peak demand. ERCOT's load forecast includes substantial demand response for crypto mining facilities and assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%.

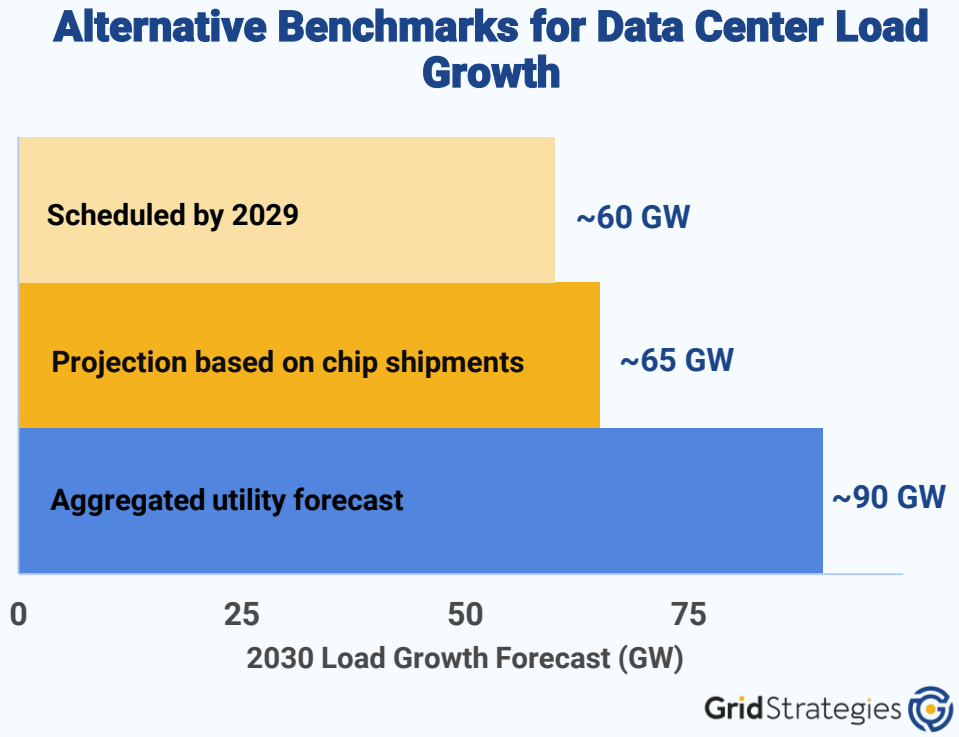
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SOURCE | Wilson, J., et al. "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers" (Nov. 2025)

Assumed data center load

The LTRA reasonably states that, “New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.” However, the growth of data centers and their contribution to peak demand may be overstated due to:

- **Supply chain shortages of chips and other key inputs.** TD Cowen estimated that due to chip limitations, U.S. data center growth would be limited to 65 GW (orange bar), about two-thirds of the data center growth assumed for the U.S. alone in the LTRA (blue).
- **Financial constraints.** Wall Street analysts have expressed concerns that expected revenues are insufficient to sustain the overall industry trajectory for AI data center investment.
- **Load flexibility.** Data centers may be able to use local generation and storage resources to reduce or eliminate their on-peak demand for grid power. Additionally, some types of data centers may opt to curtail their demand during peak periods without local supply. Curtailment activities such as these are unlikely to appear in utility forecasts of expected load. These practices may drive up annual energy use.



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SOURCE | TD Cowen, Data Centers, Generative AI, & Power Constraints: The Path Forward (May 2024); Bain & Company, “$2 trillion in new revenue needed to fund AI’s scaling trend” (Sept. 2025); Wilson, J., et al. (2025)

Assumed cryptocurrency mining load

Cryptocurrency mining accounts for about 7 GW or 15% of ERCOT's projected large load growth through 2030, though it is likely lower in other regions.

However, cryptocurrency mining data centers are understood to be more speculative than other data center types. Cryptocurrency mining facilities are highly modular and can be readily moved to different sites, even after they have been installed and put into service at a site. Unlike some types of data centers, they do not face major siting constraints due to concerns about latency or access to fiber networks. These factors increase the likelihood of "double counting."

In ERCOT, cryptocurrency mines routinely use demand response or price-sensitive demand bids to curtail demand during peak periods. If properly incentivized to do so, their contribution to peak demand can be reduced or eliminated.

Assumed Hydrogen Electrolyzer Load

Most hydrogen production load is forecast in ERCOT, where planned electrolyzers account for about 8-9 GW or 20% of ERCOT's projected large load growth through 2030. NYISO's load forecast used to include substantial hydrogen production, but it has been adjusted downward. Only a few other load forecasts mention hydrogen production, and at much lower volumes than in ERCOT. According to EIA data, the U.S. had only 116 MW of hydrogen electrolyzers in operation in 2024.

ERCOT's forecast may not reflect a full market response to congressional action to tighten the timeframe for projects to qualify for the Section 45V Clean Hydrogen Production Credit. The credit is now only available for facilities that begin construction by the end of 2027 instead of 2032.

The operation of planned electrolyzers is also difficult to forecast, but they are unlikely to fully contribute to peak load for two reasons:

- The tax credit depends on the carbon-intensity of electricity consumption. This will drive electrolyzers operation to hours with high renewable generation, which are unlikely to be periods of peak net load.
- Regardless of the tax credit, electrolyzers will tend not to operate on-peak because the electricity would be too expensive.

SOURCE | U.S. EIA "Electrolyzers are a small but growing source of U.S. hydrogen production" (2024)

Load flexibility can reduce the capacity needed for large loads

Nearly all the preceding categories of large loads can use demand response, on-site generation and storage, or price-responsive loads to reduce or eliminate their contribution to peak demand.

The LTRA assessment of ERCOT's planning reserve margin assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%. Through 2035, as load grows by 59 GW, demand response grows by 50 GW. NERC states that it made this assumption because "signed into law in June 2025, Texas Senate Bill 6 directs the Public Utility Commission of Texas to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations."

While there is considerable debate about the feasibility for some types of data centers to provide flexibility, ERCOT's requirement shows the potential impact on resource adequacy. Nonetheless, no other load forecasts used to inform the LTRA include similar load flexibility assumptions. As a result, a large share of the projected load growth in the LTRA for other regions could be negated if NERC likewise assumed, as it did for ERCOT, that large loads use some type of flexibility during peak periods. Large loads in these regions could use similar flexibility solutions. For example, Google has signed agreements with utilities to use flexibility to reduce peak load contributions from data centers in Indiana, Nebraska, Arkansas, and the Tennessee Valley Authority footprint (Google 2025).

A recent study estimates 30% of data centers may install flexible capability anyway to curtail during localized transmission system overload or contingency events, as a way to move to the front of lengthy interconnection backlogs by reducing the need for cost- and time-intensive grid upgrades (Thomas 2026). Data centers that are unable to curtail could use behind-the-meter resources during peak periods to reduce or eliminate their reliance on grid power.

SOURCE | Google "How we're making data centers more flexible to benefit power grids" (Aug. 2025); Thomas, M. "Bypassing the Grid: How Data Centers Are Building Their Own Power Plants" (Feb. 2026)

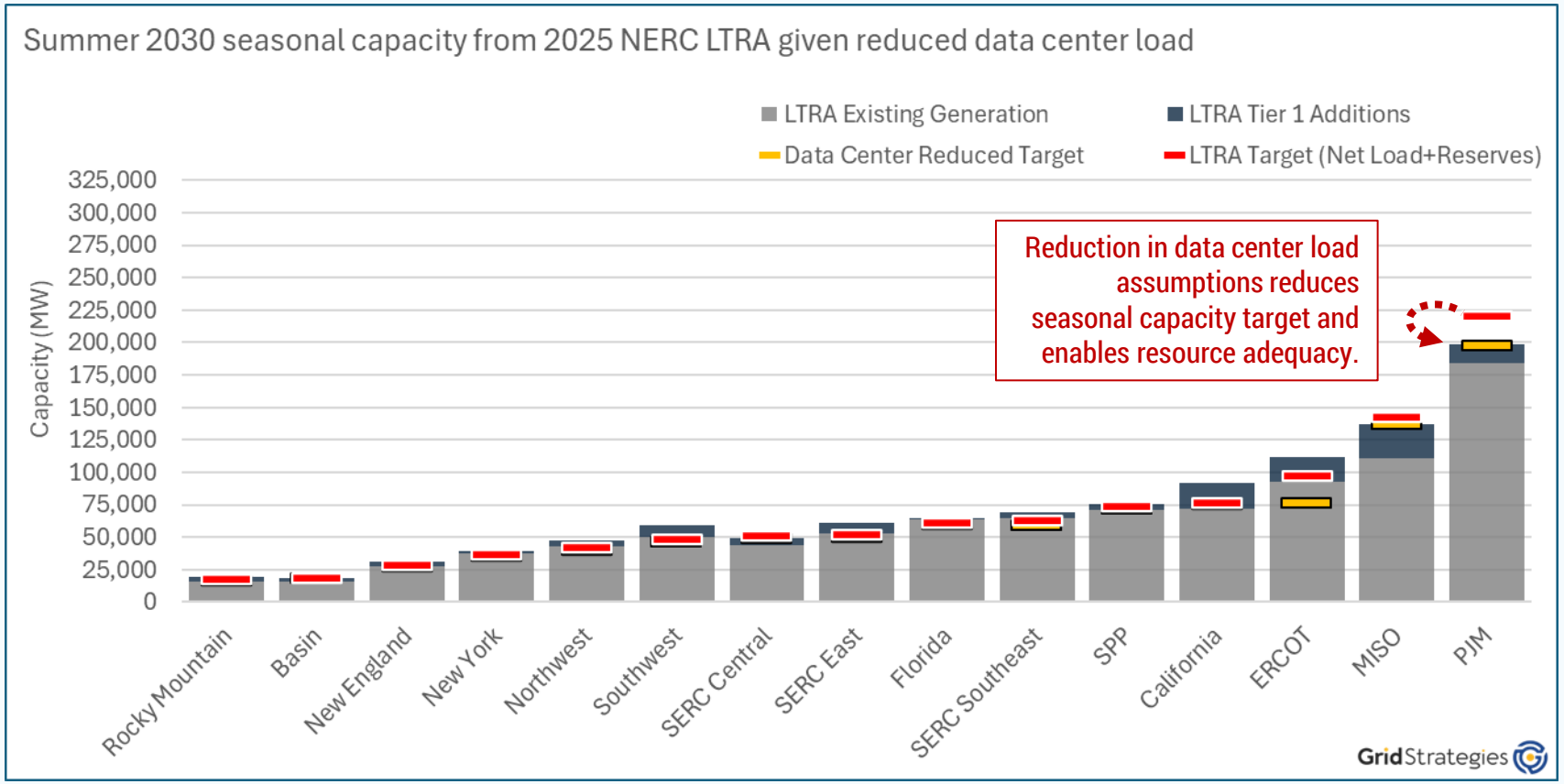
Updating data center load forecasts based on chip-industry forecasts would allow nearly all regions to meet their 2030 target needs

NERC indicates that load growth in several regions is dominated by data centers. To highlight the impacts of uncertainty in data center growth projections in the LTRA, we introduce a scenario which reduces national 2030 data center growth by two-thirds. This reduction is distributed among the regions based on their individual forecasted data center load and is shown as a yellow target in the chart.

A one-third reduction is based on chip industry forecasts and an additional one-third is based on assumed use of on-site generation during peak demand.

Consideration of potential reductions in data center load growth enables all regions to meet their 2030 peak summer load and reserve needs.

Note: If no red target is visible, then the two targets appear to overlap. All regions' net load was reduced.



GridStrategies

SOURCE | NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026)

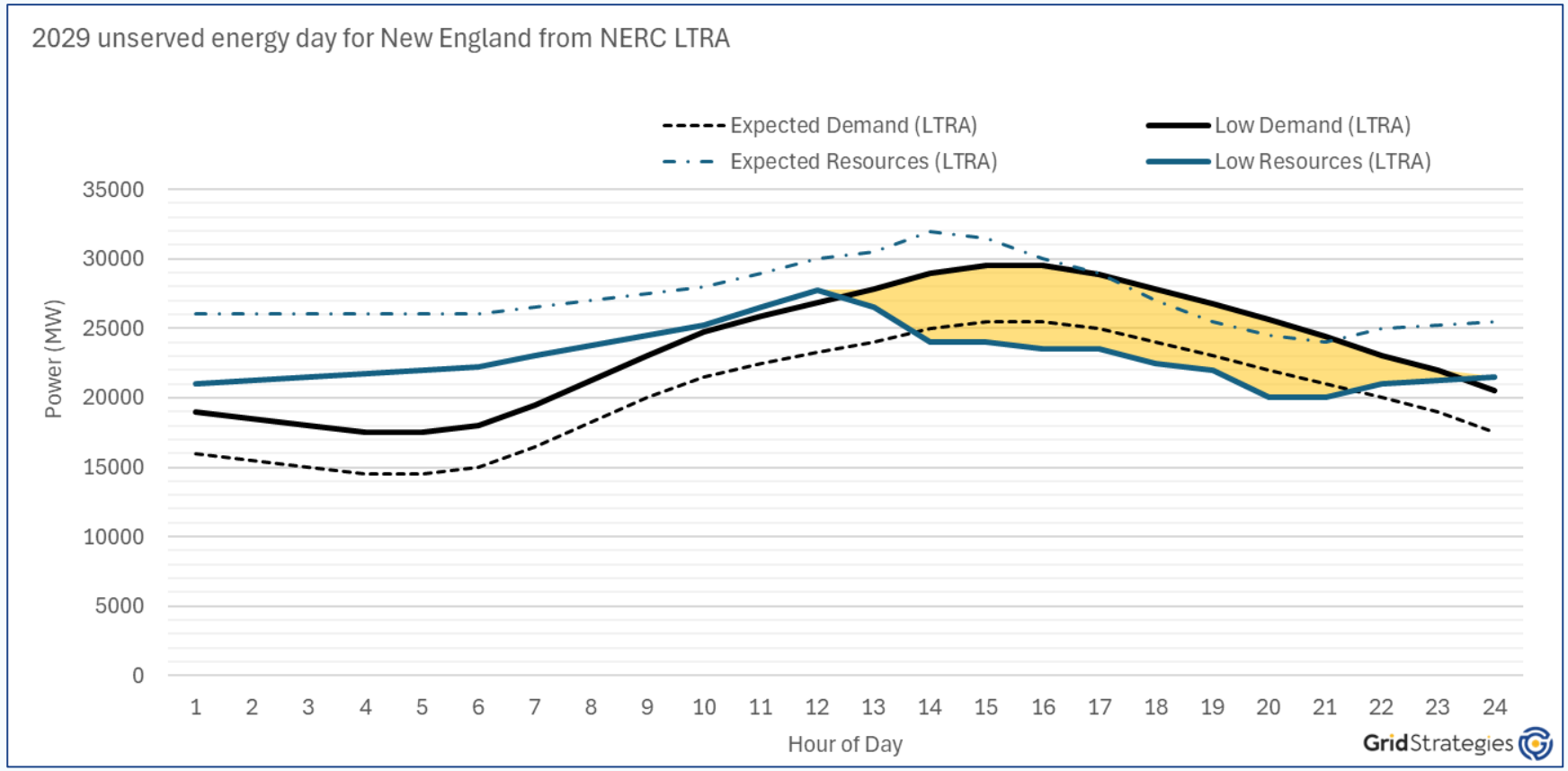
Extreme Event Energy Adequacy

Energy inadequacy risk during extreme events can exist even without seasonal capacity shortfalls. An increase in resource and interregional transfer capability also helps to alleviate extreme event risk.

The risk of energy shortfalls during extreme grid events can exist even without there being a risk of capacity shortfalls when considering only seasonal peak load. It is important to study both capacity and energy adequacy.

For example, NERC found energy shortfalls could occur during extreme heat days in New England,* even though it did not find seasonal capacity shortfalls.

Expected resource production is enough to meet expected demand (dotted lines) on most days, but sensitivity testing shows that the combination of lower-than-expected resources and high demand (solid lines) could result in energy shortfalls (yellow area). Energy shortfalls are often referred to as "unserved energy" or energy inadequacy.



*This figure is a recreation of the extreme event energy analysis shown in the LTRA for New England. We did not independently reproduce this analysis.

GridStrategies

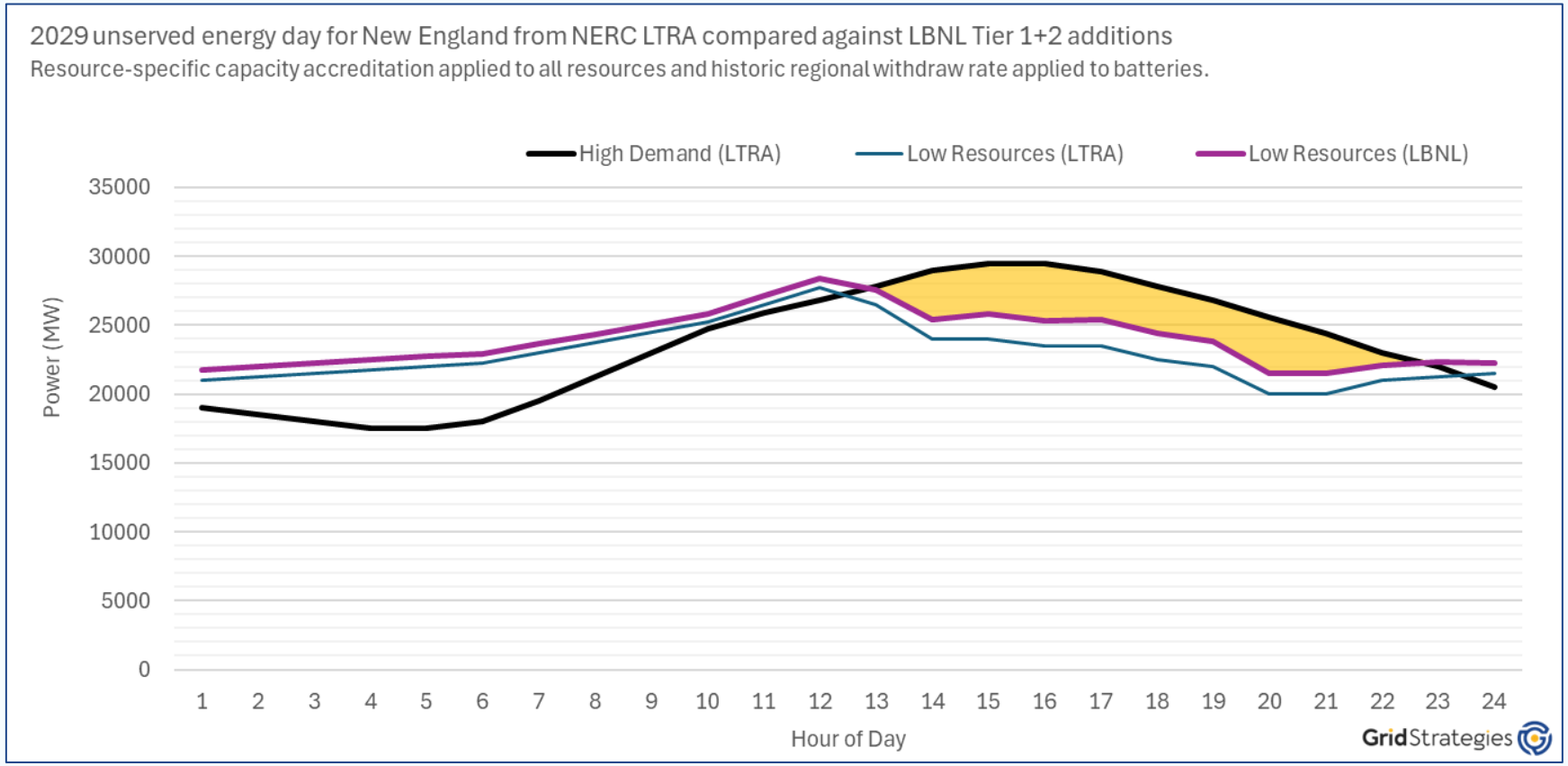
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Using LBNL resource assumptions for New England greatly reduces unserved energy risk during peak load days.

LBNL data records more solar, offshore wind, and storage resources than the NERC data.* Lower-than expected production from the LBNL-identified resource mix (purple line) better matches the times of high demand (black) than the NERC-identified resource mix (blue).

Given accredited, likely-to-connect Tier 1 and 2 resource capacity from LBNL, the amount of potential unserved energy on peak summer days in New England is reduced by nearly 40% of that calculated using NERC data. If capacity had not been reduced by expected withdrawals, the unserved energy shown here would be completely resolved.

Diverse resource mixes—especially those matched to the load profiles of the region—provide major benefits to withstand extreme grid events.



*See the Methodology section for more details.

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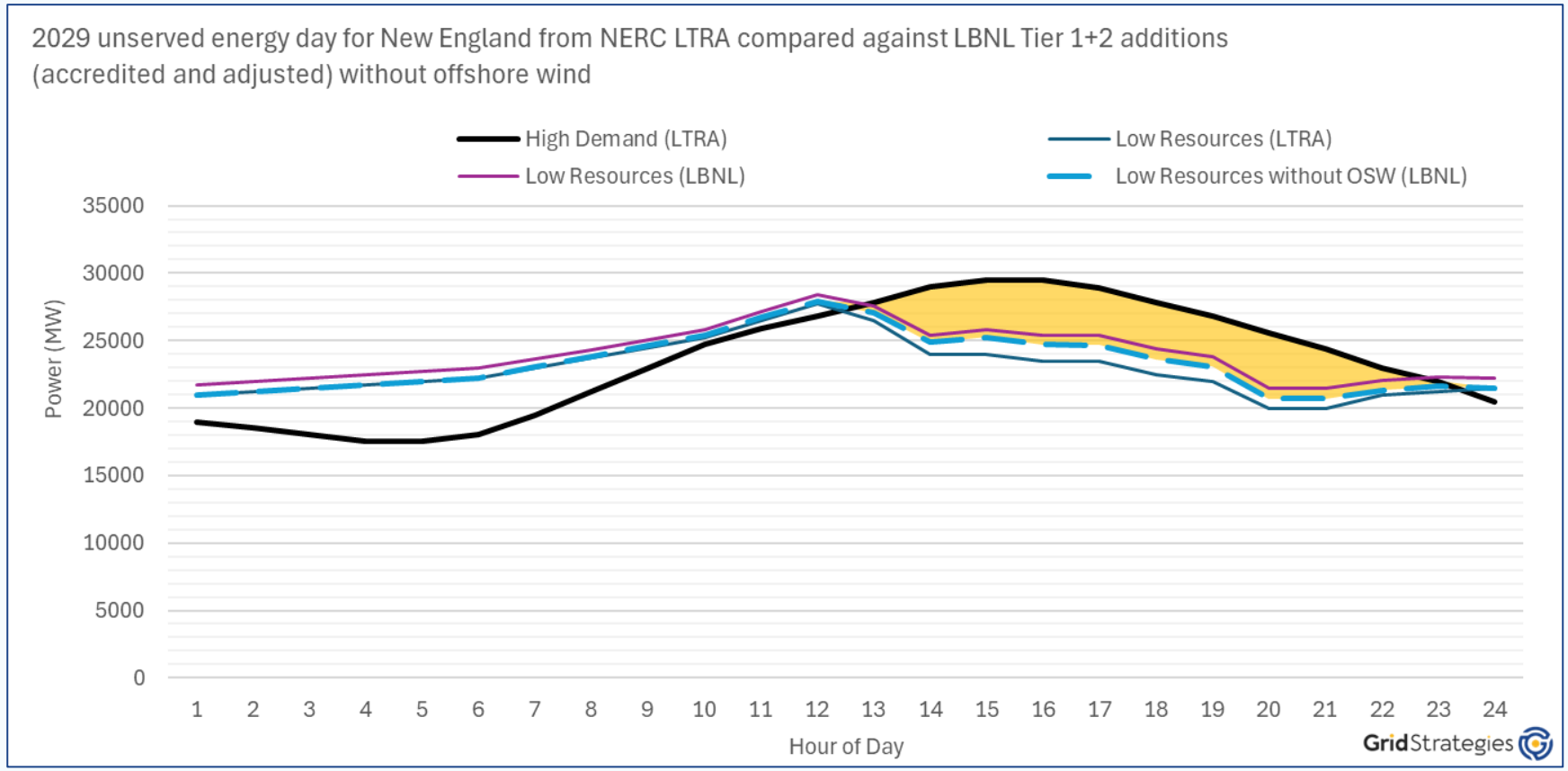
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

As with seasonal capacity adequacy, permitting and/or construction delays of resources with executed IAs are likely to exacerbate energy inadequacy risk during extreme grid events.

Delays of resources progressing through the queues or with executed IAs, whatever the cause, will exacerbate the risk of unserved energy during extreme grid events. Currently, offshore wind is facing additional permitting and construction hurdles. This is especially noteworthy for New England, where strong afternoon offshore wind output could directly reduce unserved energy risk during peak load hours.

Near-term unserved energy risk increases substantially given the delay or cancellation of planned offshore wind generation.

Given the low production of a resource mix without offshore wind (shown as the blue dotted line), the unserved energy risk is only reduced by 20% instead of 40% of that calculated in the LTRA.



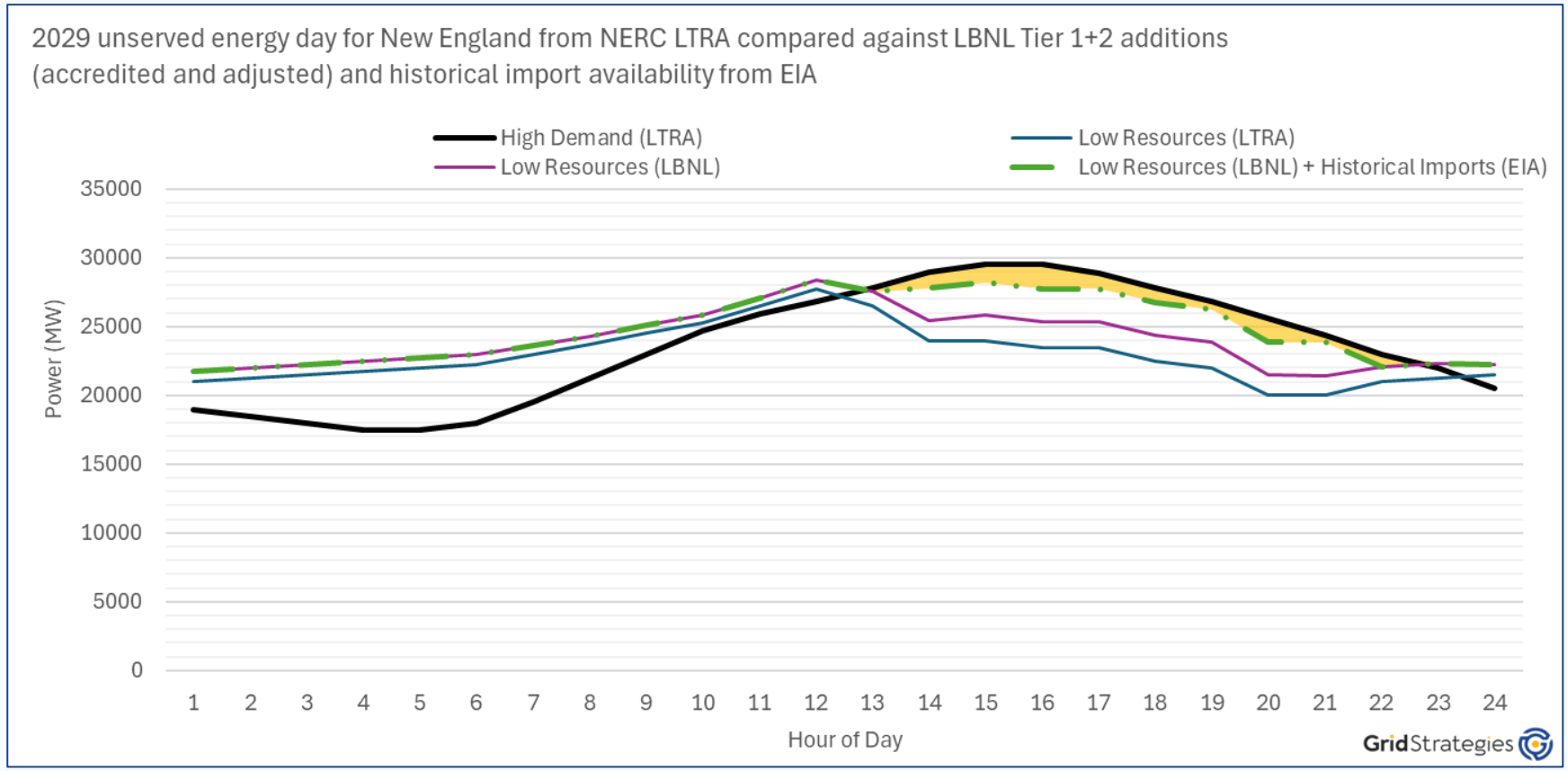
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Interregional transmission designed to move power between regions during times of grid stress further reduces unserved energy risk.

As explained in slides 15-17, NERC only includes firm imports in its seasonal capacity or energy adequacy analysis. This ignores the likelihood of additional "non-firm" imports which are historically available to regions during extreme events. Non-firm imports are those which are not contracted for use during normal operations, but that neighboring regions can export to regions experiencing heightened stress.

Adding the imports which have been historically available to New England during extreme events further reduces expected unserved energy.

The combination of likely-to-connect generation from the interconnection queues and historically available non-firm import data nearly eliminates the unserved energy risk calculated using the LTRA assumptions.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

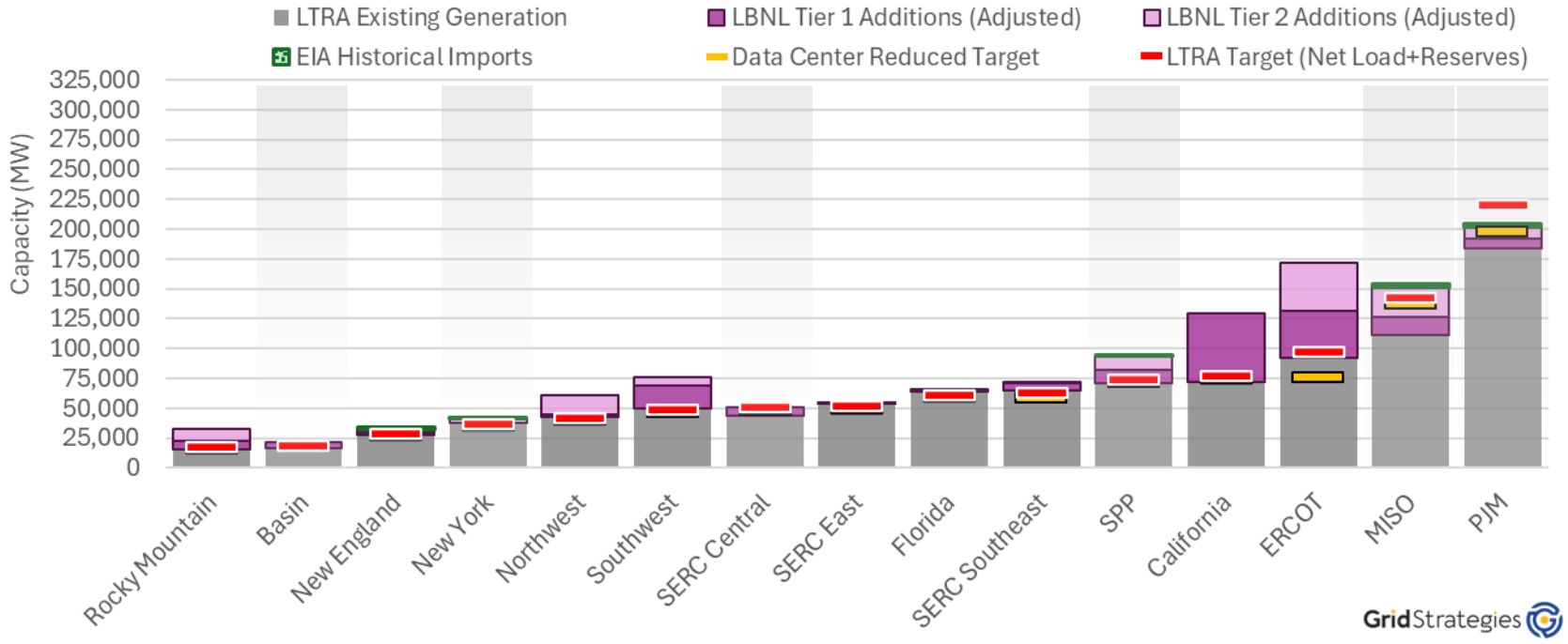
Conclusions and Solutions

In this analysis, we considered different assumptions for generation resource, interregional transmission, and demand than the LTRA. The combination of all three suggest all regions could be resource adequate.

The regional seasonal resource adequacy risks identified in the 2025 NERC LTRA are all resolved when evaluated under different input assumptions:

- Including generation that is actively working through the interconnection queues in each region (Tiers 1 & 2)
  - Discounting all generation nameplate capacity by the resource and region-specific accreditation methods
  - Discounting generation queue data by historic regional and phase-specific withdraw rates
- Consideration of historic non-firm imports during extreme events
  - Including increased interregional transfer capability capacity (albeit low likelihood of 2030 in-service date)
- Reduced data center load to account for microchip industry supply chain constraints and generation flexibility

Summer 2030 seasonal capacity with queue additions from LBNL database (adjusted for expected withdrawals), interregional import capacity (adjusted for historical imports), and reduced data center load



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

While reduced risk is likely given different assumptions, these results should not be taken for granted. Enacting existing solutions is needed to stave off future reliability risk.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Methodology

The NERC LTRA assesses each region's ability to meet both its future capacity and energy adequacy needs.

NERC's LTRA importantly captures potential reliability issues for a snapshot in time. Risk is defined by tightening reserve margins—the difference between electricity demand and available supply.

In its 2025 version, NERC identified several regions* as either **High** or **Elevated** risk of not being able to meet their future capacity and energy needs.

Seasonal capacity shortfall risk: MISO, PJM, and SERC-Central (with SPP and Basin on the margin)

Extreme event energy shortfall risk: MISO, PJM, New England, New York, SERC-East, Basin, Northwest, and ERCOT

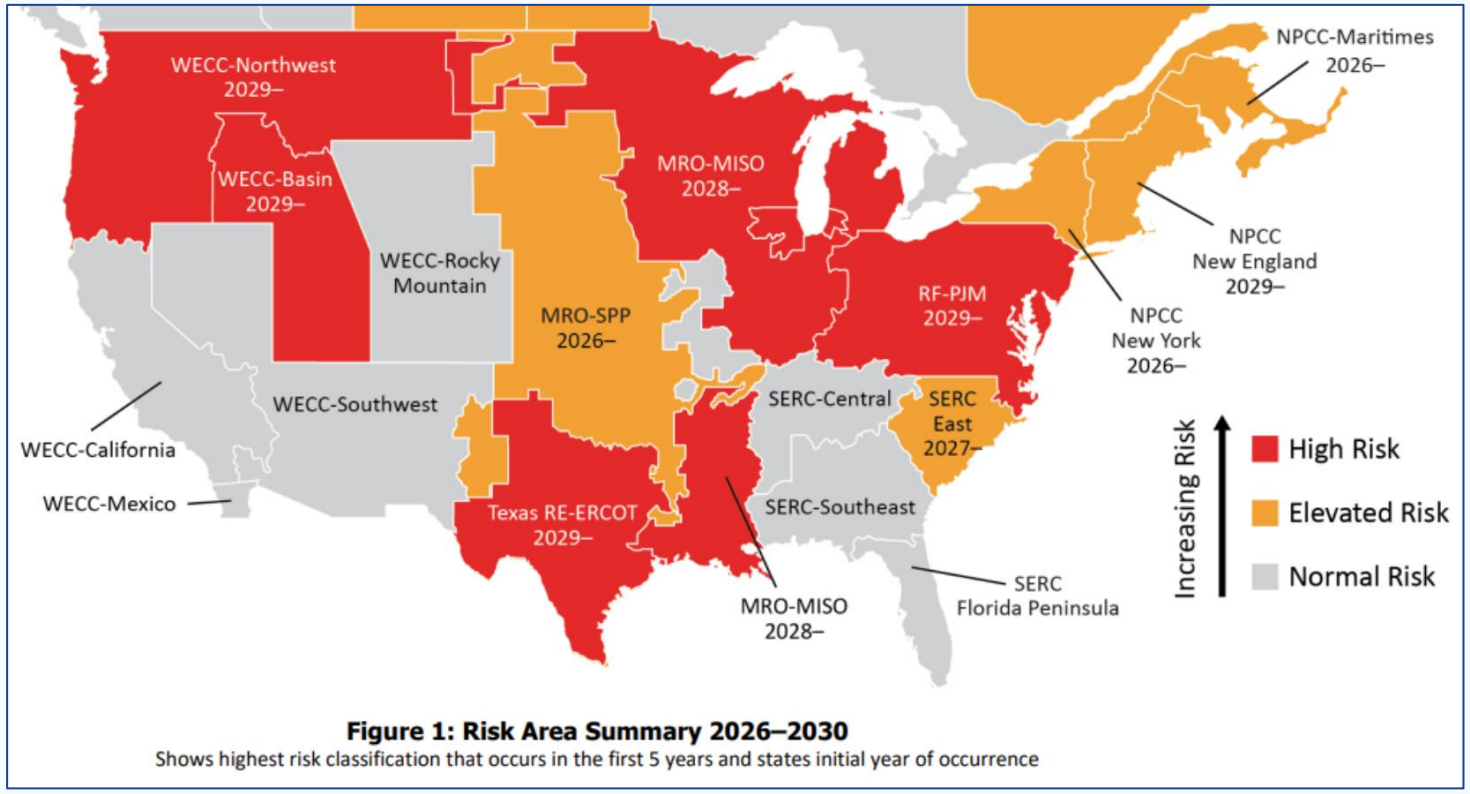


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

*NERC did not mark SERC-Central as elevated risk despite showing large seasonal shortfalls while SPP was marked as elevated risk despite having neither seasonal capacity shortalls nor extreme event energy shortfalls.

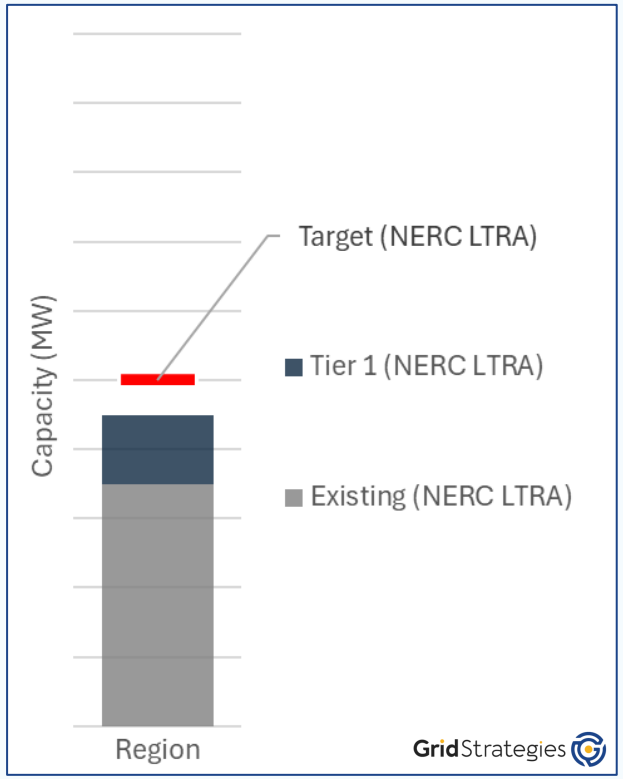
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SOURCE | NERC "2025 LTRA" (2026)

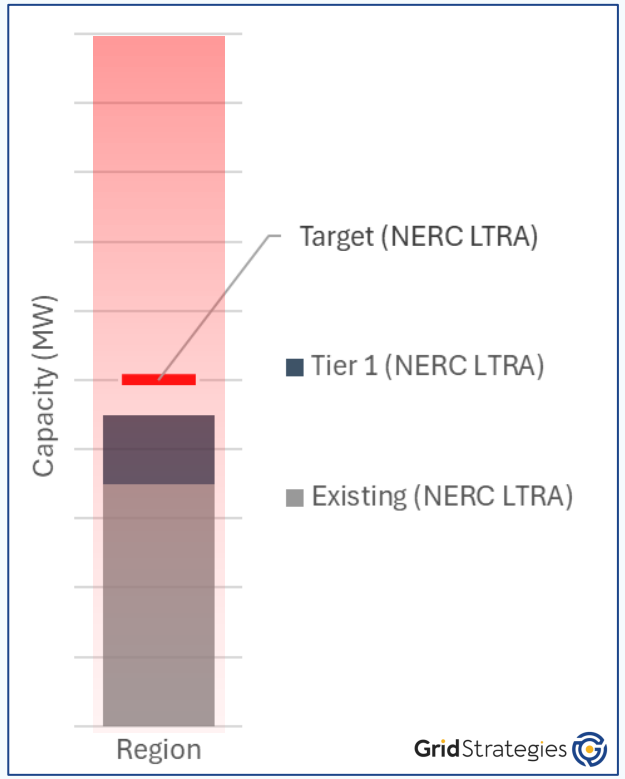
Illustrative walkthrough of seasonal capacity slides

Bar charts showing the existing (light grey) and future (dark blue) resource capacity in each region using NERC LTRA data. The target capacity (red line) is also shown. These charts were created by Grid Strategies using NERC data.

A red highlight is used to signify a shortfall between the existing + future resource capacity and the needed target to meet future load and reserves. A yellow highlight would be used to signify a "near miss."



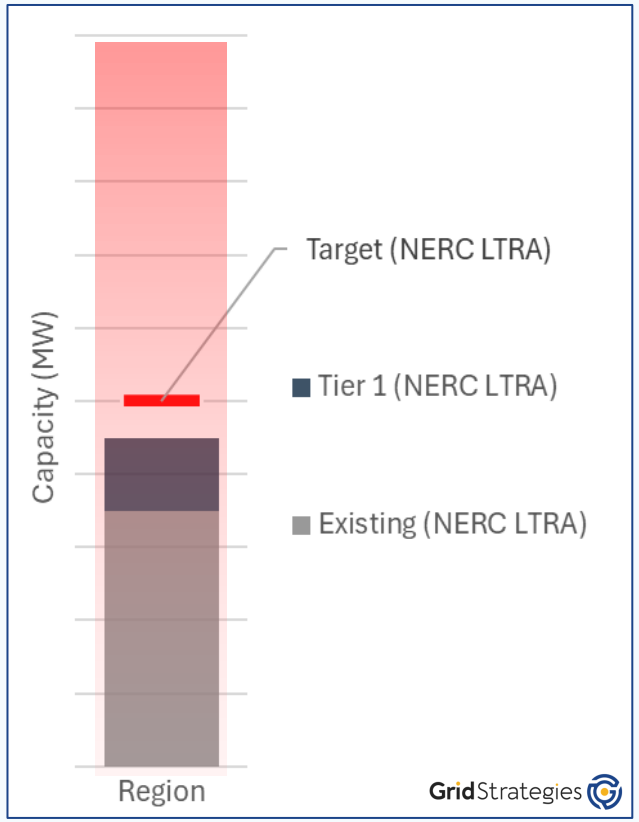
Highlight important features of chart



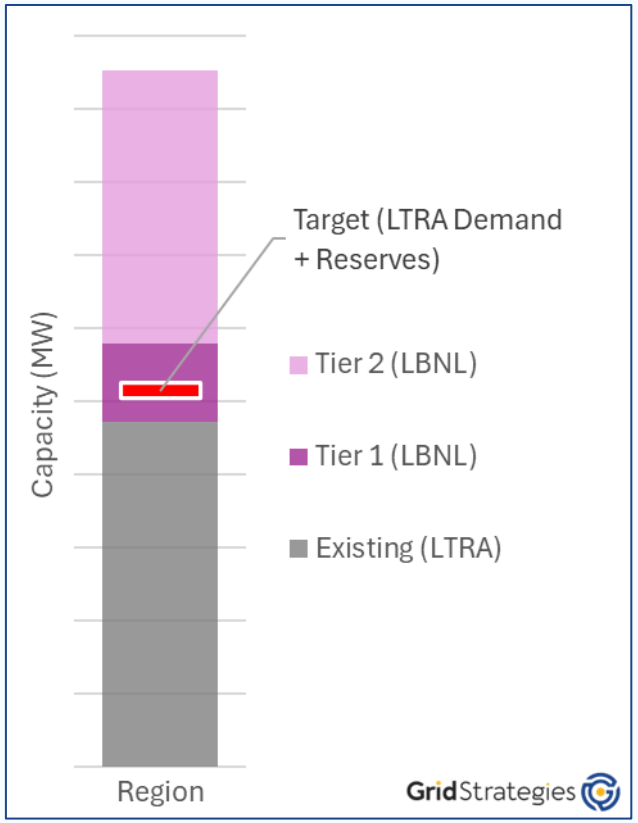
Illustrative walkthrough of seasonal capacity slides

Replace the NERC LTRA resource capacity data with accredited LBNL interconnection queue data (purple) for comparison. Existing and target data is from LTRA and remains unchanged unless specified.

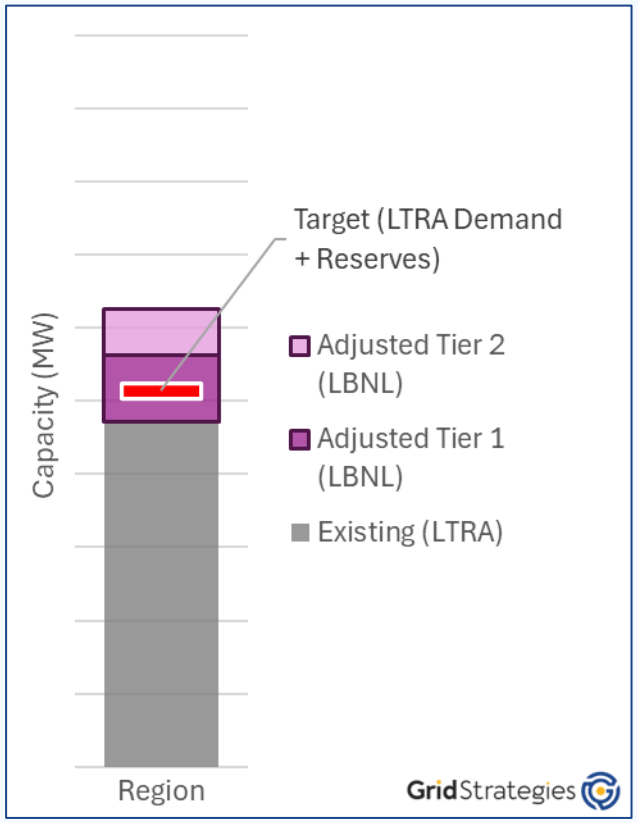
To avoid overcounting queue generation, the LBNL data is discounted based on regional- and study phase-specific withdraw rates.



Replace NERC data with resource-accredited LBNL data



Reduce LBNL data based on expected withdraws



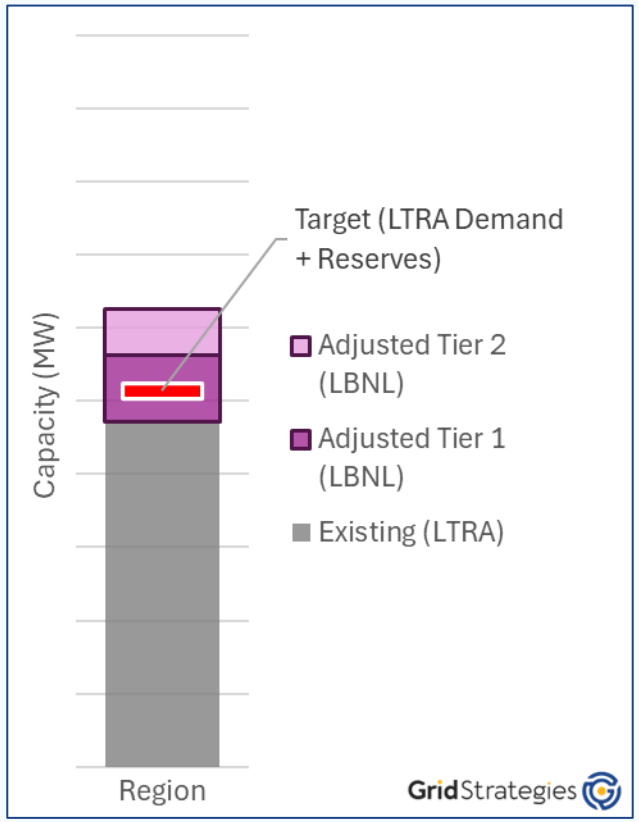
Note red highlight is removed because adequacy has been achieved

GridStrategies

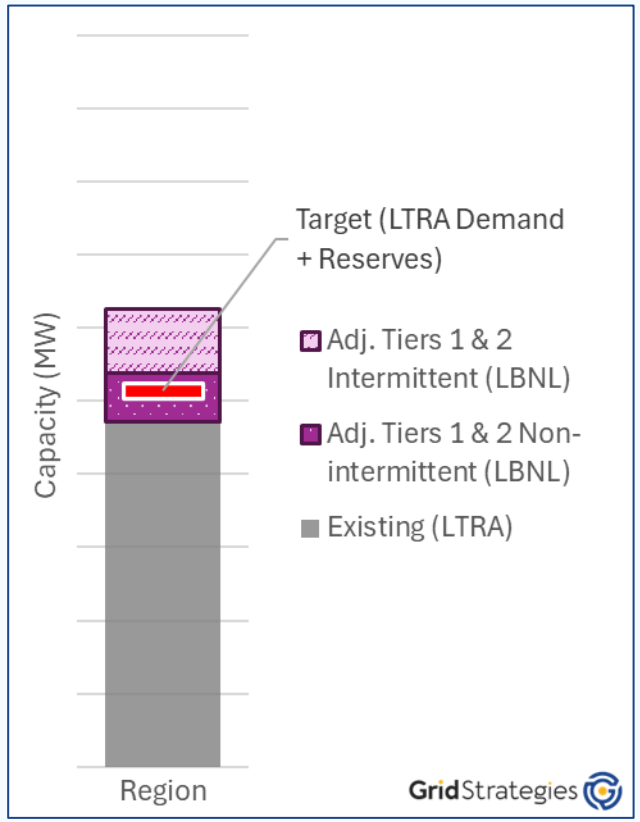
Illustrative walkthrough of seasonal capacity slides

Analyze the LBNL resource data to gain insight into future capacity risk. Purple is still used for LBNL data while different bar borders or pattern are used to indicate interesting features of the data.

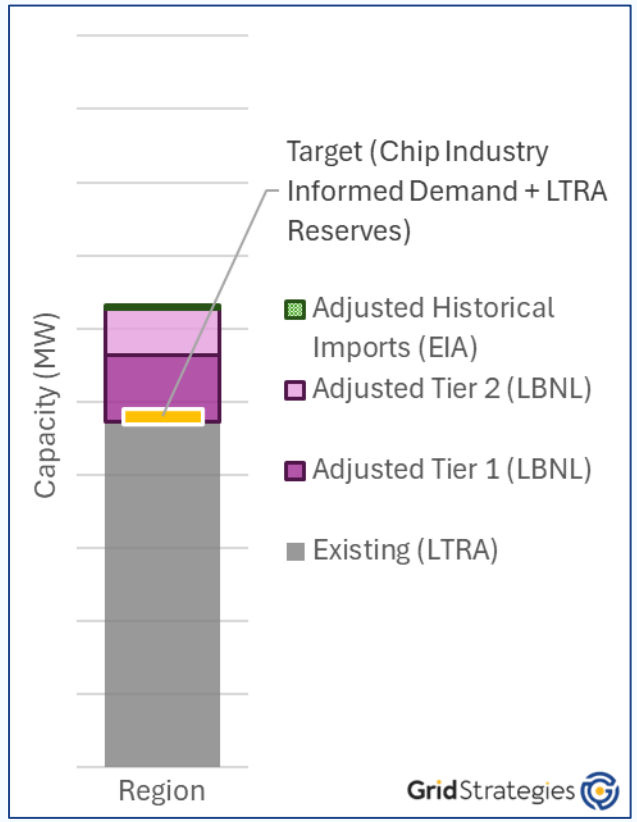
Interregional transfer capability data is adjusted using EIA data to better illustrate available capacity. In some cases, the expected load is changed to match demand forecasts from other sources.



Look at different features of LBNL data



Continue to add more data for analysis



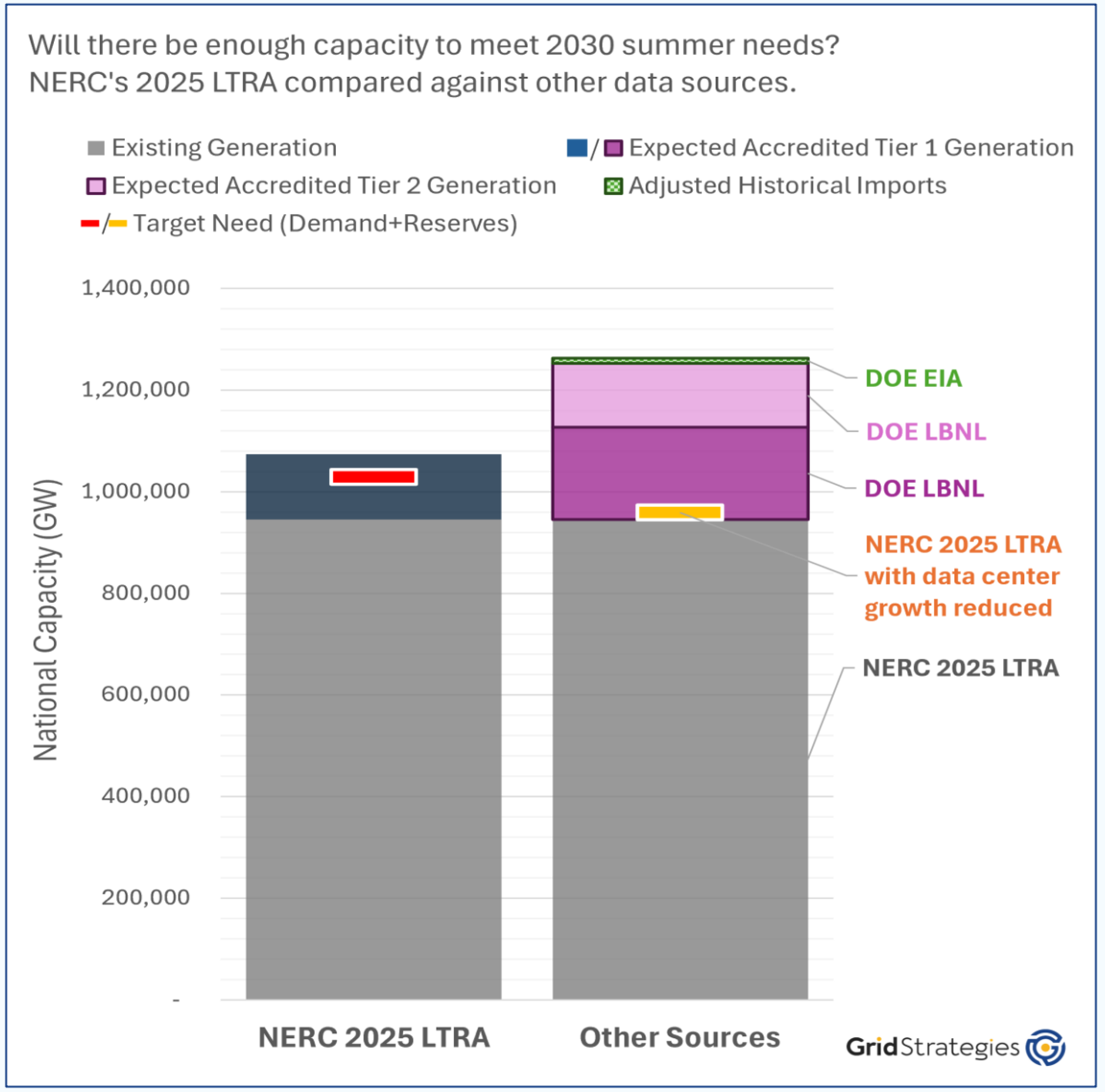
Summary slide of seasonal capacity differences in 2030

On Slide 6, the comparison of NERC 2025 LTRA analysis against our analysis using other sources is meant as an illustrative comparison of the national risk given the use of different credible data sources.

The NERC 2025 LTRA bar was made by summing the forecasted 2030 summer load + reserves (target), existing generation, and Tier 1 data for each region directly from the NERC data.

The target value shown in "Other Sources" was created by applying a one third derate to known data center load growth in all regions. The one-third derate factor is the ratio of estimated data center growth in 2030 from chip shipments to the estimated growth from utility roll-ups as used by LTRA (Wilson, J., et al. 2025). Another one-third derate factor is from the assumption that many data centers are likely to use some form of on-site generation or storage to curtail their peak demand (Thomas, M., 2026). The known data center load growth is from Grid Strategies analysis of total system load growth that is attributable to data centers (Wilson, J., et al. 2025). The impact of this data center growth reduction scenario on individual regions is shown in slide 24.

The generation resources shown in "Other Sources" is the sum of resources available in the LBNL dataset that are reasonably expected to connect by 2030. Adjusted historical imports represent the non-firm imports that have been available during grid stress events from the Energy Information Administration. More detail on the other sources data is provided in subsequent slides.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026); Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Analysis using LBNL data: Regional assessment areas

The DOE's Lawrence Berkeley National Laboratory collects data from the generation interconnection queues for seven ISOs / RTOs and 49 non-ISO balancing areas (including utilities and Power Marketing Administrations), representing roughly 97% of currently installed U.S. generating capacity. This data is compiled annually with help from Interconnection.fyi and is posted for public view at emp.lbl.gov/queues. The 2025 dataset includes data through the end of 2024.

The 56 entities in the LBNL database were mapped to the NERC LTRA assessment areas by geography (maps to the right). The non-RTO utilities were mapped as follows:

WECC California
- LADWP
- SMUD
- WAPA-SN

WECC Rocky Mtn
- CLPT
- BHCT
- CSU
- PacifiCorp
- PRPA
- PSCo
- TSGT
- WAPA-RM

WECC Northwest
- Avista
- BHP
- BPA
- CPUD
- GrantPUD
- MPC
- NWMT
- PGE
- PSE
- TPU
- WAPA-IS

WECC Basin
- IdahoPower

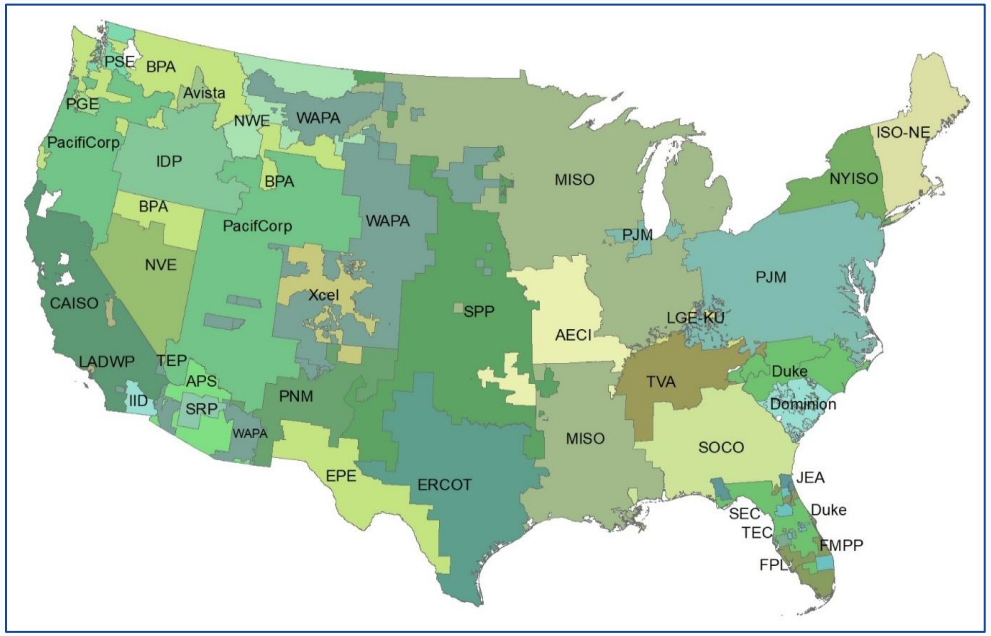
WECC Southwest
- APS
- EPE
- IID
- N-C
- NVE
- PNM
- SRP_ANPP
- SRP
- SRP_Gila
- SRP_PV-PC
- SRP_SWV
- TEP
- WAPA-DSW
- WAPA-MPP

SERC Central
- AEC
- LGE-KU
- TVA

SERC Southeast
- GTC
- SOCO

SERC Florida
- OUC
- TEC
- Duke (FL)

SERC East
- Dominion
- S-C
- Duke (non-FL)



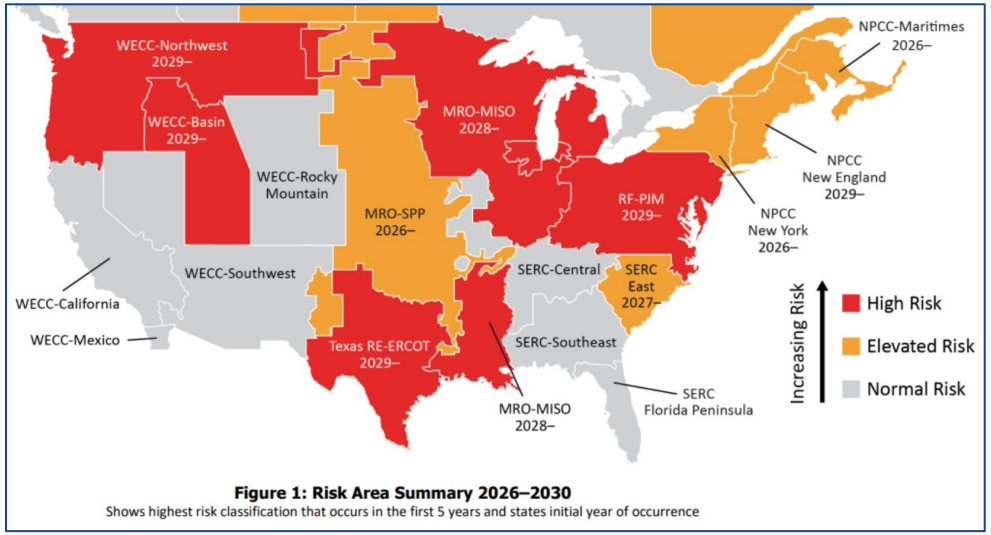


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis of LBNL data: Generation tier status

LBNL interconnection data is organized by its queue status and study phase in the interconnection queues. Queue status refers to if the facility is completed, withdrawn, or actively progressing through the queues.

NERC organizes in-development generation resources by Tiers, where:

- Tier 1 are resources with executed interconnection agreements
- Tier 2 are any resource that is in the study process, and
- Tier 3 are those that have submitted interconnection requests but are not yet under study.

The cross-walk between LBNL's "Queue Status" and "IA Status Clean" fields and the NERC Tiers used in this analysis are shown to the right. Interconnection requests marked as Active in the Queue Status are organized into Tiers based on their IA Status.

Resources considered in to be in advanced Tier 2 status were those with either "IA Pending" or "Facility Study" status in the LBNL data. Suspended interconnection requests are considered Tier 2 because they have already completed some study phases but have paused their continuation of progress. Requests that un-pause often enter at the same study stage. Requests of Unknown or N/A status are considered Tier 3 because their existence in the database indicates an interconnection request has been made, but whether studies have begun cannot be said for sure.

LBNL Queue Status	NERC Tier
Active	(see IA Status)
Withdrawn	Cancelled
Operational	Operational
Suspended	Tier 2
Unknown	Tier 3

LBNL IA Status Clean	NERC Tier
Withdrawn	Cancelled
Operational	Operational
IA Executed	Tier 1
Construction	Tier 1
IA Pending	Tier 2
Facility Study	Tier 2
Cluster Study	Tier 2
System Impact Study	Tier 2
Feasibility Study	Tier 2
Combined	Tier 2
In Progress (unknown study)	Tier 2
Suspended	Tier 2
Not Started	Tier 3
N/A	Tier 3

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Expected withdraw rates

To reduce the likelihood of overcounting generation resources that may not interconnect, we reduced all Tier 1 and 2 resource data in the LBNL queue dataset given region- and status-specific historic withdraw rates.

LBNL publishes the completion rates (as of 2024) of all resources in the regional queues that entered the queue between 2000 and 2019. The withdraw rates vary regionally between 64% and 85%. LBNL also provides information about the queue study phase that projects were in when they withdrew. In general, fewer projects withdraw once they reach advanced stages of the interconnection queue process.

Applying the regional withdraw rates to all generation without regard for its queue location would overly discount generation in Tier 1 and advanced Tier 2 status. Instead, we adjust the amount of generation that is expected to withdraw from each Tier separately. See illustrative figure to the bottom right.

We first calculate the total amount of expected regional withdraws by applying the appropriate withdraw rate to the sum of all Tiers 1, 2, and 3 generation in each region's queue. We assume that 15% of generation in Tier 1 status will withdraw, equivalent to the share of withdrawn requests between 2019 – 2023 in the IA executed phase from LBNL's analysis. Because no generation in Tier 3 is expected to interconnect by 2030, we assume 100% of Tier 3 generation withdraws for every region. The difference between the total amount of expected regional withdraws and that which is assumed to withdraw from Tiers 1 and 3 in each region is applied to the Tier 2 data.

LBNL: Historical completion by region for requests submitted 2000-2019 (as of 2024)

Region	Active	Operational	Withdrawn
CAISO	14%	9%	77%
ERCOT	14%	22%	64%
ISO-NE	8%	18%	74%
MISO	9%	15%	76%
NYISO	7%	8%	85%
PJM	8%	14%	77%
SPP	9%	14%	76%
Southeast	5%	9%	85%
West	13%	9%	79%

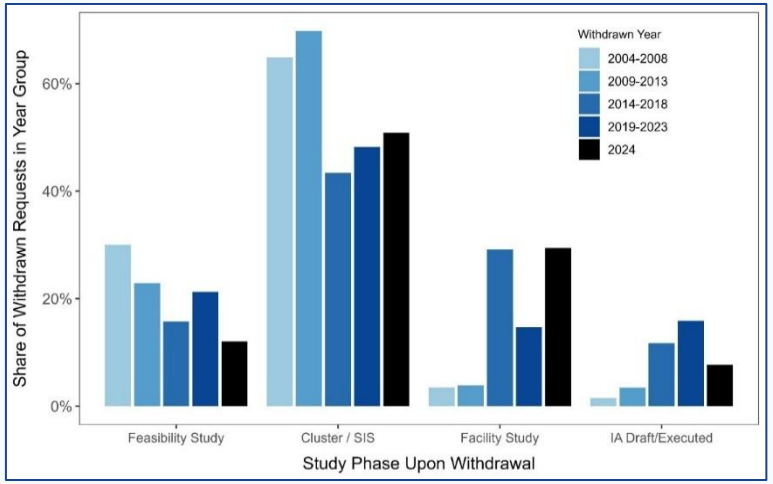
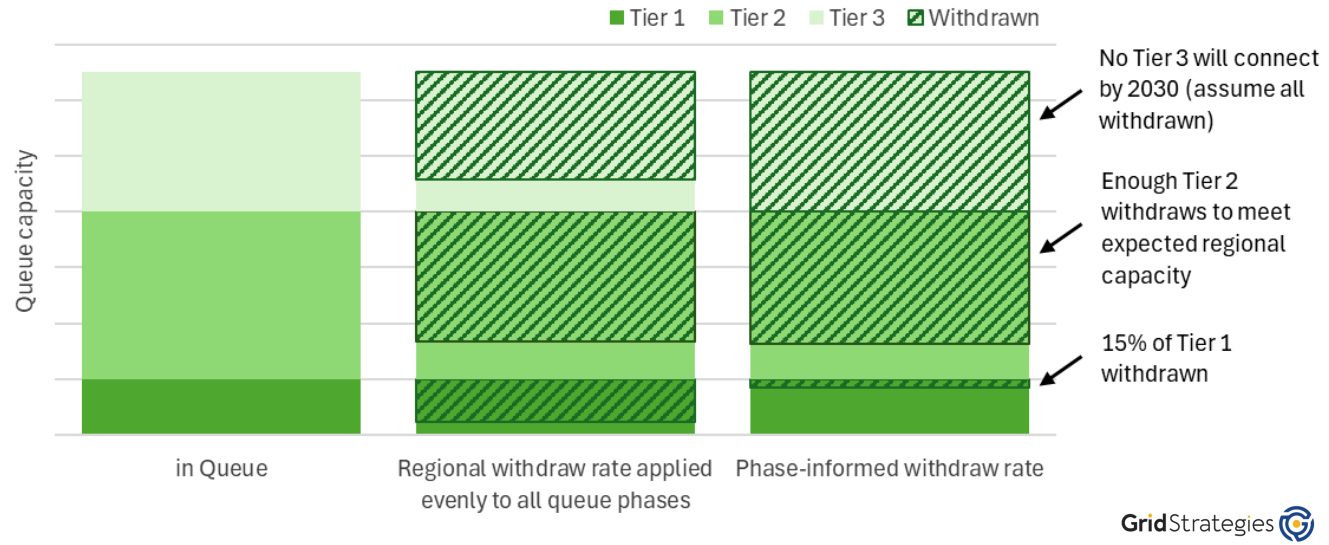


Illustration of two different methods to apply regional withdraw rates to interconnection queue data. The same amount of generation capacity withdraws in both methods.



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SOURCE | Rand, J., et al. (2025)

Analysis using LBNL data: Resource type

LBNL interconnection data is organized by generation resource type. When multiple resource types (e.g., gas and battery storage) are combined into one interconnection request, LBNL lists each resource type. The LBNL database includes a "type_clean" field, which summarizes all types of resources included in the interconnection entry.

These "clean" resource types are organized into a fewer number of categories in our analysis for simplicity. The cross-walk is provided in the two tables to the right.

LBNL Clean Type	Resource Type
Battery	Battery
Offshore Wind+Battery	Battery Hybrid
Other+Battery	Battery Hybrid
Solar+Battery	Battery Hybrid
Solar+Other+Battery	Battery Hybrid
Solar+Wind+Battery	Battery Hybrid
Wind+Battery	Battery Hybrid
Geothermal	Geothermal
Solar+Other	Hybrid
Solar+Wind	Hybrid
Wind+Other	Hybrid
Hydro	Hydro
Offshore Wind	Offshore Wind
Other	Other
Hydrogen	Other Storage
Other Storage	Other Storage
Solar	Solar
Battery+Other Storage	Storage Hybrid
Other+Battery+Other Storage	Storage Hybrid
Solar+Battery+Other Storage	Storage Hybrid
Solar+Wind+Other Storage	Storage Hybrid
Wind	Wind

LBNL Clean Type	Resource Type
Coal	Coal
Gas+Battery	Firm Hybrid
Gas+Battery+Diesel	Firm Hybrid
Gas+Coal	Firm Hybrid
Gas+Diesel	Firm Hybrid
Gas+Oil	Firm Hybrid
Gas+Other	Firm Hybrid
Geothermal+Battery	Firm Hybrid
Hydro+Battery	Firm Hybrid
Oil+Battery	Firm Hybrid
Oil+Coal	Firm Hybrid
Oil+Other	Firm Hybrid
Other+Coal	Firm Hybrid
Other+Diesel	Firm Hybrid
Solar+Diesel	Firm Hybrid
Solar+Gas	Firm Hybrid
Solar+Gas+Battery	Firm Hybrid
Solar+Geothermal	Firm Hybrid
Solar+Hydro	Firm Hybrid
Wind+Gas	Firm Hybrid
Gas	Gas
Diesel	Oil
Oil	Oil
Nuclear	Nuclear

GridStrategies

SOURCE | NERC "ES&D" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Accredited capacity

No resource will produce electricity at its rated capacity ("nameplate") all the time. To account for this, regions apply an accredited value to a resource to indicate a percentage of the nameplate capacity that can be expected to perform during peak demand. The accredited value of a resource varies by fuel type, season, year, and geographic location.

Each region calculates accredited capacity differently. Some consider historic forced outages of a resource type (which tend to overestimate availability) while others use modeling tools to determine how much load a resource can be expected to carry in future years given numerous system dynamics.

The LBNL interconnection queue database provides nameplate values for all generators in the queues. To ensure only a reasonable amount of new resources are accounted for in our analysis, we seasonally accredit each resource type based on the region-specific method used locally for resource accreditation. If a region does not use seasonal or resource-specific accreditation, a neighboring region's method is used.

Unless otherwise noted:

- Battery Hybrid resources are equivalent to battery resources' accredited values
- Firm Hybrid resources are the average of firm resources' accredited values
- Hybrid resources are the average of wind and solar resources' accredited values
- Other resources are the average of any remaining resources' accredited values not otherwise listed

Region	Accreditation Method & Source	Notes
MISO	2025-2026 DLOL	Summer & winter values. Battery resource uses storage (blended) and storage hybrid uses pumped storage DLOL. MISO values are also used for all other regions' resources that are not otherwise noted.
SPP	ELCC for Summer 2026	Summer values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	ELCC for Winter 24/25	Winter values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	25/26 EFORd	Summer & winter values used for all non variable resources. Oil and other resources are RICE with on-site storage, gas is CC. Values also used for ERCOT other; WECC summer other storage.
ISO-NE	CAR-SA: Impact Analysis 1/14/26	Summer & winter values. Used for solar, wind, and hydro resources
ISO-NE	2025 Capacity, Energy, Loads, and Transmission (CELT) Report	Summer & winter values. CELT used for battery, battery hybrid, coal, gas, nuclear, offshore wind, oil, other, and other (pumped) storage resources.
NYISO	2025-2026 Final Capacity Accreditation Factors	Summer values used for both seasons. Rest of state values used for battery (6-hour), hydro, offshore wind, other, other storage (pumped storage), solar, wind.
NYISO	2024 Review of EFORd	Summer & winter values. NYCA values used for coal (steam turbine), gas (CC), nuclear (steam turbine), oil (jet engine). NYISO values are also used for SERC-E summer battery and summer wind.
PJM	2027/2028 ELCC Class Ratings	Summer values used for both seasons for all resources. Battery is 6-hour CSR, battery hybrid is configuration 3, gas is CC, other is waste-to-energy, other storage is other unlimited resources, solar is fixed-tilt, storage hybrid is configuration 1. PJM values also used for SERC-E hydro, nuclear, oil, other, and other storage resources.
ERCOT	25/29 CDR	Summer & winter values for battery (6-hr), other storage (12-hr), solar, and wind. Values also used for SERC-FP and SERC-SE battery.
SERC	2025 CRP Chapter 3	Winter values used for both seasons. 2030 Reference case used for battery (standalone BESS), battery hybrid (synergistic BESS), offshore wind (avg. ELCC for first 800MW), solar (avg. ELCC for first 10 GW of standalone), wind (avg. ELCC for DEP and DEC for first 300 MW).
SERC	2023 Wind ELCC Study	Average ELCC of 5GW and 15GW standalone solar used for all SERC regions' summer solar.
Southwest	E3 2023 Resource Adequacy in the Desert Southwest	2033 values also used for WECC regions' winter battery, summer hydro, summer nuclear, winter and summer wind (unless otherwise stated).
Northwest	E3 2025 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results	Winter values for Greater Northwest used for WECC regions' gas, other storage, solar, wind (unless otherwise stated).
Northwest	E2 2019 Resource Adequacy in the Pacific Northwest	Winter values for 2030 Reference scenario used for WECC regions' coal, geothermal, hydro, nuclear (unless otherwise stated).
CAISO	2026 Net Qualifying Capacity (NQC) for RA Resources	Summer and winter values used for CAISO geothermal, hydro, other (biomass), solar, wind. Values also used for other WECC regions' other, solar, hydro and geothermal (unless otherwise stated).
National	NREL VRE ELCC Study	Median offshore wind used for SERC-FP (SERC), ERCOT, WECC-NW (NorthernGrid), CAISO

Adding historically available interregional transfer capability to the seasonal capability analysis

The EIA historical imports included in the charts on slides 16 and 29 take the difference between the historical import availability (2015 and 2025) from the U.S. EIA Form 930 data and the 2030 firm import assumptions in the LTRA. The last column subtracts imports from demand in all peak hours over the last decade and shows the minimum reduction in in-region generation due to imports.

For New York, an additional 1,250 MW of import availability was added to the EIA Form 930 data to account for the energization of the Champlain Hudson Power Express transmission line.

Comparison of on-peak net imports in four regions as assumed by LTRA against actual, in MW. Exports are negative.

	LTRA 2026 Assumption	LTRA 2030 Assumption	Historical Availability (2015-2025)
MISO	2,809	2,509	5,344
SPP	-18	-78	1,421
ISONE*	567	84	2,464
NYISO	3,405	3,486	2,730†
PJM	3,840	0	2,937‡

*Data for New England (ISONE) predates completion of the 1200 MW New England Clean Energy Connect with Hydro Quebec, so on-peak imports will likely be higher going forward.

† EIA data for New York does not include the Champlain Hudson Power Express, a 1,250 MW line connecting Quebec to New York City that is slated for completion in 2026. Once that is included, NYISO imports should be roughly in line with the LTRA.

‡ The EIA data show PJM was exporting during most peak demand periods over the last decade, so it is not possible to estimate the historical availability of imports for PJM. PJM administratively sets its capacity benefit of ties (non-firm imports) at 1.5% of nameplate generation procured in the capacity market, calculated here as 1.5% for 195,831 MW in the 2025/2026 Base Residual Auction. In its 2023 reserve margin analysis, PJM calculated 6,474 MW in total diversity benefit with its neighbors, much higher than the capacity benefit of ties shown in the table.

GridStrategies

SOURCE | EIA, "About the EIA-930 data" (accessed Feb. 2026); PJM, "2025/26 Base Residual Auction Report" (2024); Brooks, A. et al. (2025)

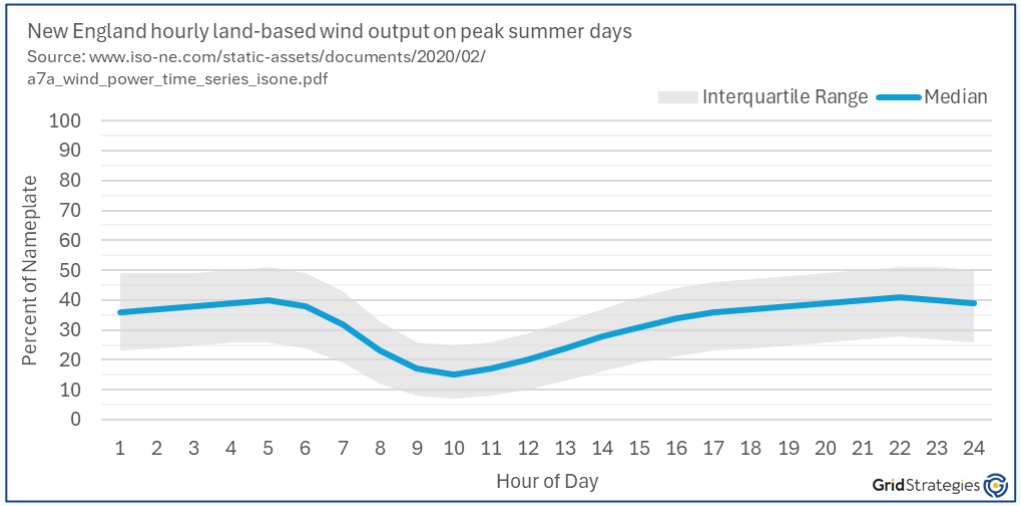
Analysis using LBNL data: New England wind and solar production

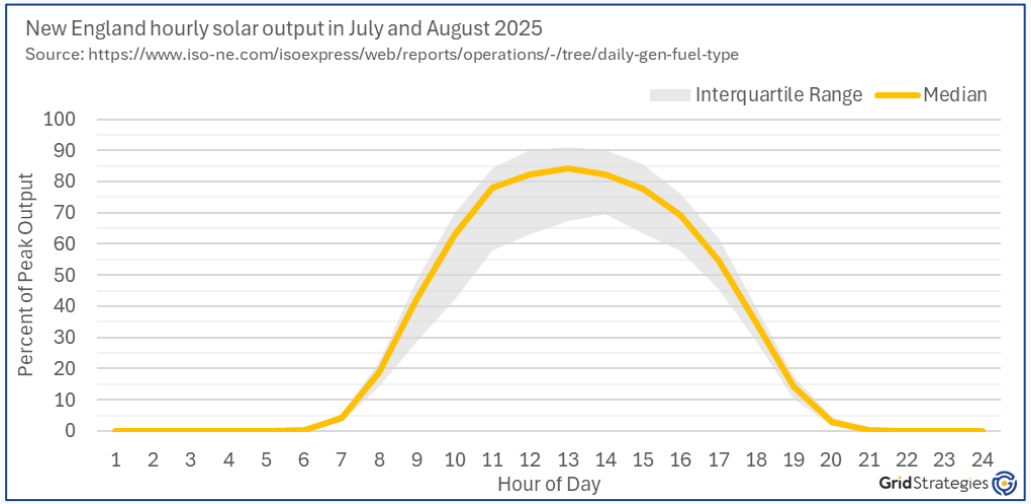
In order to use LBNL data for energy analysis for New England, we compare the amount of Tier 1 and Tier 2 LBNL data against NERC (slide 46). This required an understanding of the generation output in New England during summer months for different resource types.

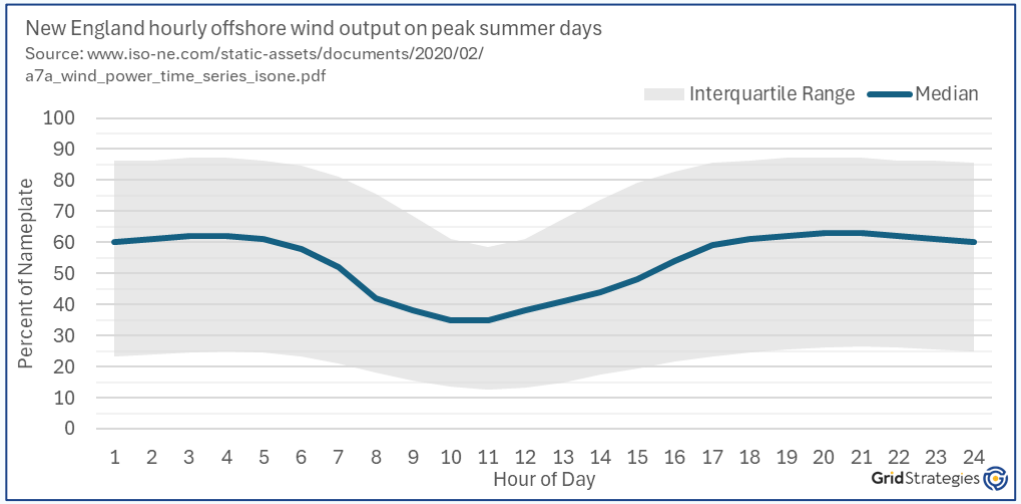
On the right are the hourly median and interquartile range for wind and offshore wind production in New England during peak demand days. This data was collected between 2012 and 2018 by ISONE to help them understand wind output during times of grid stress.

Also shown is the median and interquartile range for average hourly solar output in July and August of 2025, also from data collected by ISONE.

The hourly median data was used to estimate the output of both land-based and offshore wind in New England during peak summer 2029.







GridStrategies

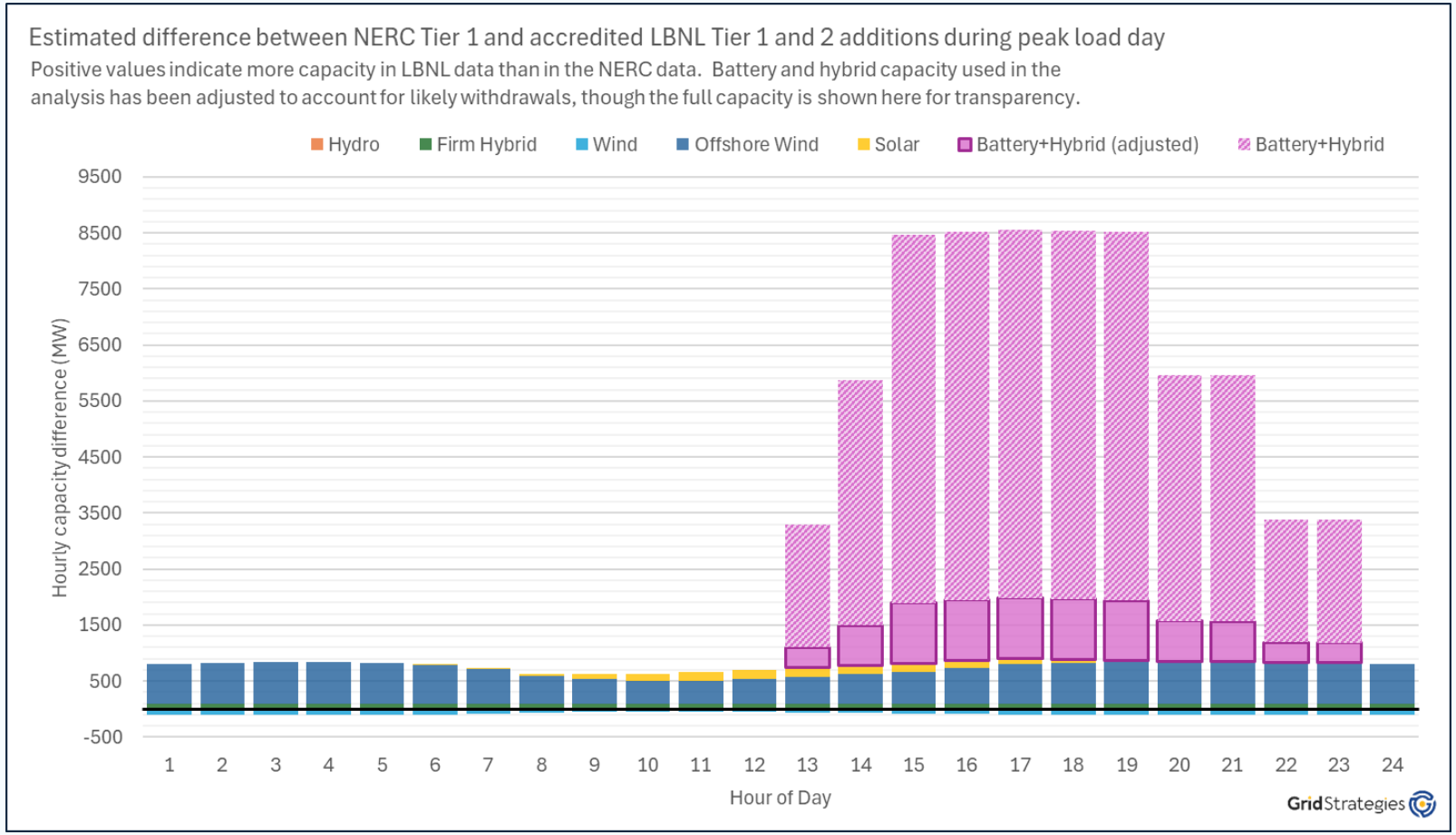
SOURCE | Judd, S. "Wind and Power Time Series Modeling of ISO-NE Wind Plants" (2020); ISONE "2025 Hourly Solar Generation" (2026)

Analysis using LBNL data: New England hourly production

Shown here is the potential change in hourly energy output for New England on peak load days given the different resource mixes between the LBNL and NERC data. Positive values indicate LBNL recorded more capacity for that resource type while negative values indicate NERC recorded more capacity.

As explained on slide 45, we adjusted the hourly production of each resource type to match expected peak day behavior, given regional resource accreditation methods. Battery and battery hybrid resources are expected to discharge at partial capacity for all hours of unserved energy, modulating their output so that no one resource discharges for longer than 6 hours. Given the large quantity of battery and hybrid resources in the LBNL data, these resources were additionally discounted by the historic withdraw rate of the region.

Given the data available, we cannot replicate the energy inadequacy analysis presented in the LTRA exactly. We provide this rough estimate to understand how different generation assumptions would impact unserved energy results.



SOURCE | NERC "2025 LTRA" (2026); NERC "2024 LTRA" (2025); NERC "ES&D" (2026); Rand, J. et al. (Aug. 2025)

EXHIBIT 131-7

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Dockets UE-260005 & UG-260006
Puget Sound Energy
2026 General Rate Case

WUTC STAFF DATA REQUEST NO. 008:
REQUESTED BY: Chris McGuire

RE: Large Load Customers and Data Centers

Please identify all existing and prospective data centers in your service territory. Include project name, location, requested interconnection capacity (MW), expected in service date(s), and expected annual energy use (MWh) at full build out.

Response:

For purposes of responding to WUTC Staff Data Request Nos. 008 through 020, Puget Sound Energy ("PSE") has interpreted the term "large load" consistent with the following definition of the term created by the North American Electric Reliability Corporation ("NERC") Large Load Task Force:

> Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more points of interconnection that can pose reliability risks to the [Bulk Power System] due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces.[1]

Although the NERC Large Load Task Force has not yet provided a demand threshold or more granular characteristics of large loads, the Large Load Task Force anticipates further analysis and has forthcoming developments.[2] PSE proposes a demand threshold of 20 megawatts (MW) to maintain consistency with the definition of the term "data center" discussed below. As of March 31, 2026, the NERC Large Load Task Force has not yet defined the term "data center" or sought to distinguish between data centers and other large load facilities, such as cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces.

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1 N. Am. Electric Reliability Corp., White Paper: Characteristics and Risks of Emerging Large Loads at 1 (2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.

2 *Id*. at 2.

For purposes of responding to WUTC Staff Data Request Nos. 008 through 020, PSE has interpreted the term "data center" consistent with the following definition used by the PSE Customer Engagement group:

> A data center is a physical room, building, or facility with an aggregate contract demand of 20 MW or more and houses information technology (IT) infrastructure for building, running, and delivering applications and services. It also stores and manages the data associated with those applications and services.

For purposes of the above definition, the PSE Customer Engagement group adopted a demand threshold of 20 MW, which is consistent with the definition of the term "emerging large energy use facility" in Engrossed Second Substitute House Bill 2515:[3]

> (14) "Emerging large energy use facility" means a facility that has *a maximum aggregate contract demand of 20 megawatts or more* and is primarily engaged in providing a service described under code 518210 of the 2022 North American industry classification system.[4]

There are no data centers located within PSE's electric service territory operating at a demand of 20 megawatts or more.

Over the period beginning January 1, 2023, through March 31, 2026, PSE has received inquiries from 27 potential large loads and data centers that might be located within PSE's electric service territory. None of the above potential large loads has progressed beyond exploration and study phases or has made commitments to locate within PSE's electric service territory. PSE does not consider potential load requests as probable until the customer commits to construction.

Of these 27 potential large loads and data centers, the following ten remain in study phases:

Project	Type	Requested Load (MW)	Location (County)	Request (Quarter)
Phase 1: Exploratory Conversations				
None				
Phase 2: Feasibility Assessment				
Potential Facility 14	Large Load	35	King	Q3 2024
Potential Facility 25	Data Center	65	Whatcom	Q3 2025

[3] H.B. 2515, 69th Leg., 2026 Reg. Sess. (Wash. 2026) (Engrossed Second Substitute), https://lawfilesext.leg.wa.gov/biennium/2025-26/Pdf/Bills/House%20Bills/2515-S2.E.pdf.

[4] *Id*. at 3 (italics added).

Project	Type	Requested Load (MW)	Location (County)	Request (Quarter)
Potential Facility 26	Data Center	75	King	Q3 2025
Potential Facility 27	Large Load	177	King	Q3 2025
Phase 3: Solutions Study				
Potential Facility 08	Data Center	70	King	Q1 2024
Potential Facility 10	Data Center	200	King	Q2 2024
Potential Facility 12	Large Load	50	King	Q3 2024
Potential Facility 20	Data Center	100	King	Q1 2025
Potential Facility 23	Data Center	80	Kittitas	Q2 2025
Potential Facility 24	Large Load	45	King	Q3 2025
Phase 4: Request for Service; Proceed with Construction				
None				

Of these 27 potential large loads and data centers, the following 17 have withdrawn their requests:

Project	Type	Requested Load (MW)	Location (County)	Request (Quarter)
Withdrawn Requests				
Potential Facility 01	Large Load	260	Whatcom	Q1 2023
Potential Facility 02	Large Load	50	King	Q1 2023
Potential Facility 03	Large Load	33	King	Q1 2023
Potential Facility 04	Large Load	165	Skagit	Q2 2023
Potential Facility 05	Large Load	200	Skagit	Q4 2023
Potential Facility 06	Data Center	300	King	Q4 2023
Potential Facility 07	Data Center	110	King	Q1 2024
Potential Facility 09	Data Center	30	King	Q2 2024
Potential Facility 11	Data Center	250	Pierce	Q3 2024
Potential Facility 13	Large Load	150	Skagit	Q3 2024
Potential Facility 15	Data Center	50	King	Q3 2024
Potential Facility 16	Data Center	35	Thurston	Q4 2024

Project	Type	Requested Load (MW)	Location (County)	Request (Quarter)
Withdrawn Requests				
Potential Facility 17	Data Center	100	King	Q4 2024
Potential Facility 18	Data Center	24	King	Q4 2024
Potential Facility 19	Data Center	1000	Thurston	Q4 2024
Potential Facility 21	Data Center	20	Thurston	Q1 2025
Potential Facility 22	Data Center	50	Pierce	Q2 2025

EXHIBIT 131-8

Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges

SYLVAN ENERGY ANALYTICS



Elaine Hart, Sylvan Energy Analytics

Washington UTC and Department of Commerce Resource Adequacy Meeting

June 22nd, 2026

This work was sponsored by GridLAB

Who we are

SYLVAN ENERGY ANALYTICS

Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.

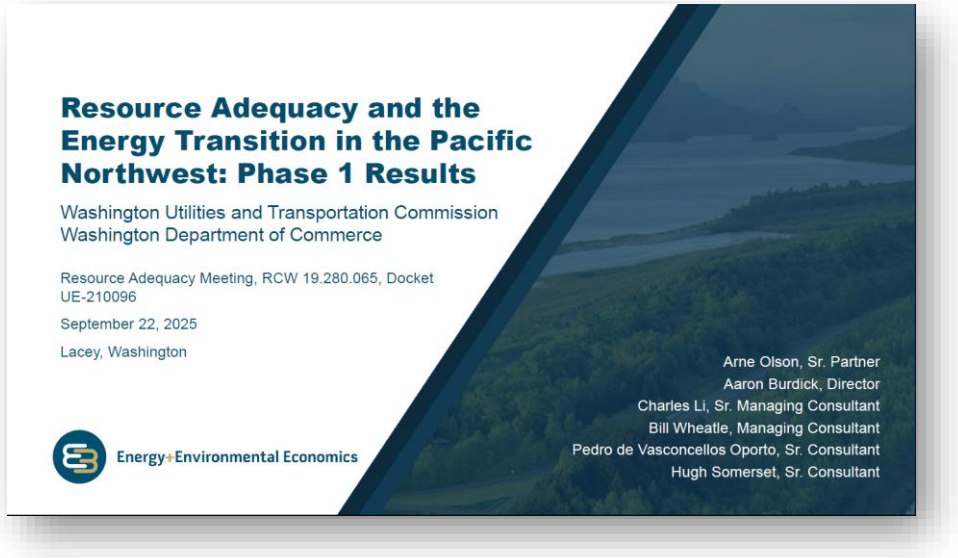
GridLAB

GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
  - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
  - It projected a 9 GW shortfall by 2030 across the "Greater NW," with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
  - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
  - Phase 2 has since been released, with similar findings
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3's analysis and findings and identify near-term opportunities to support regional RA



Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High
Hydro flexibility	• E3 study may underestimate weekly energy shifting available from hydro dispatch • E3's load following hydro dispatch assumption may overlook contributions from short-duration storage	Uncertain (requires further study)
Imports and coordination with California	• E3 study assumptions may slightly underestimate import winter capability • Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)	Low
Retirements and conversions	• Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation • E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)	Low-to-moderate

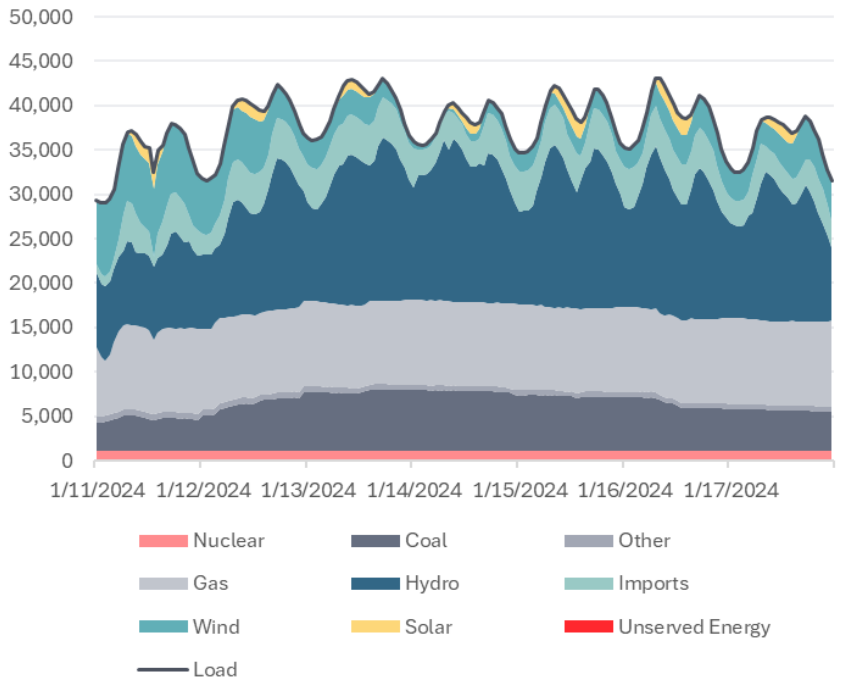
Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the "Greater NW" that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run



Alternative 2030 load scenarios

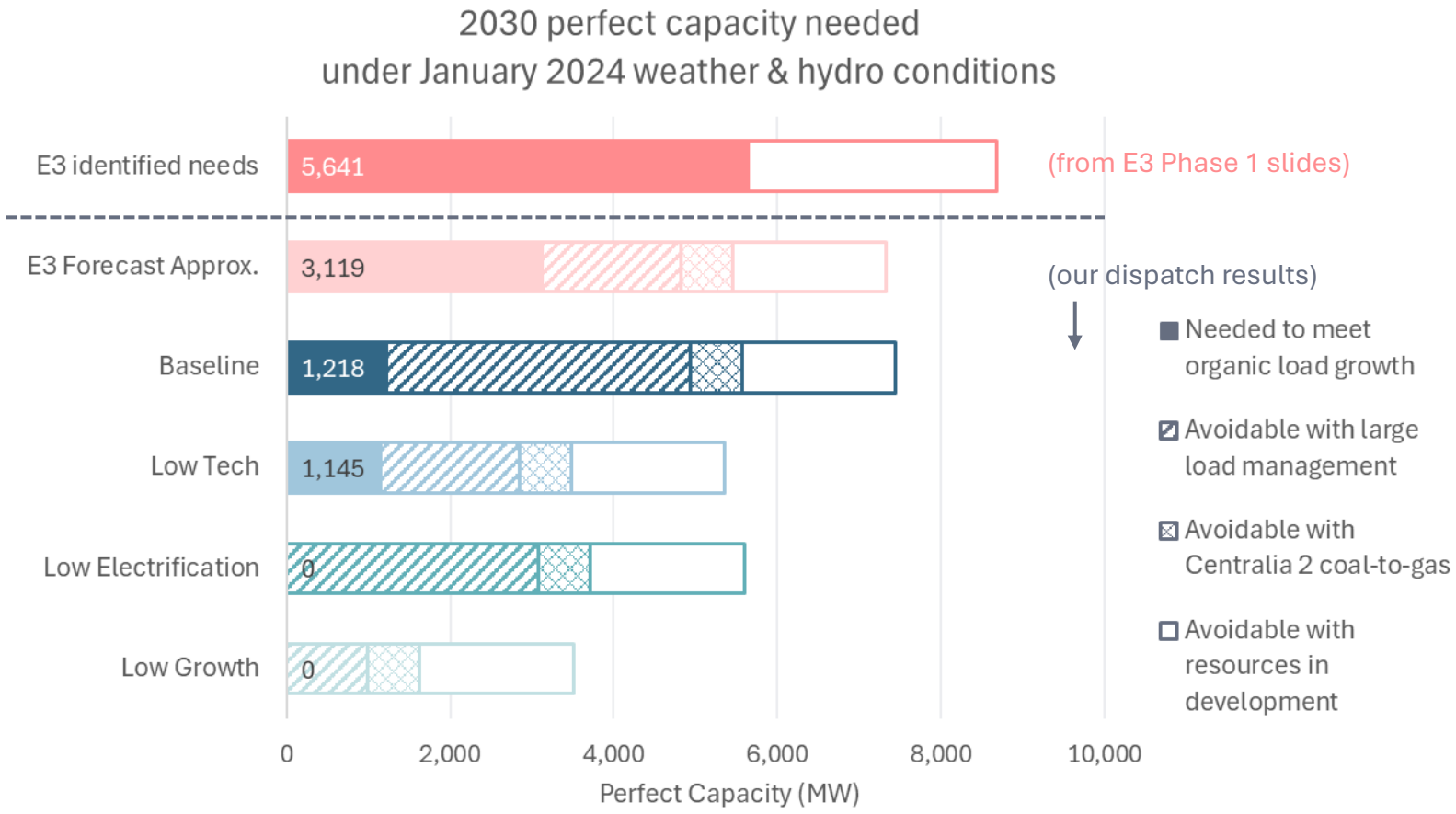
We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

A wide range of potential needs and a crucial role for data center flexibility

- The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
- Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

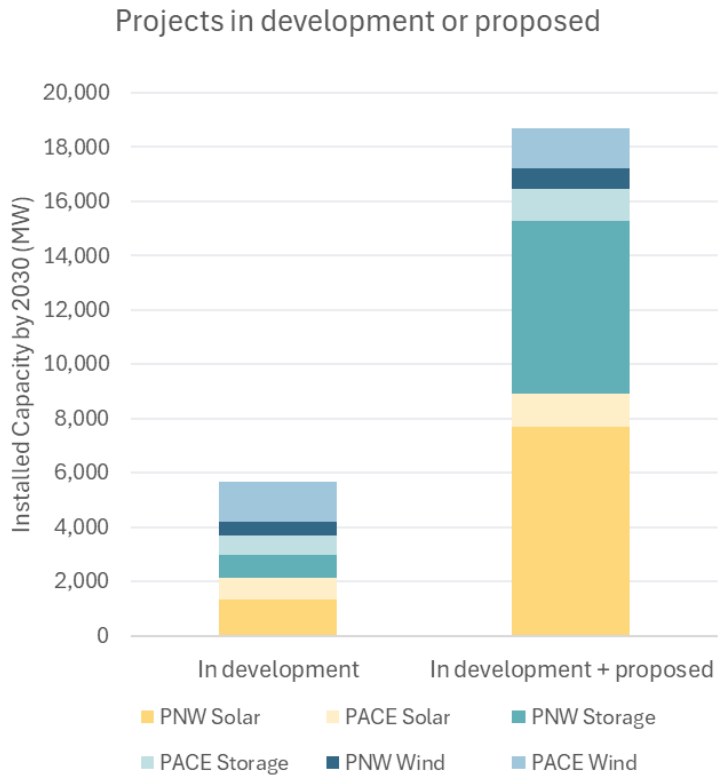


Winter portfolio ELCCs of new clean resources

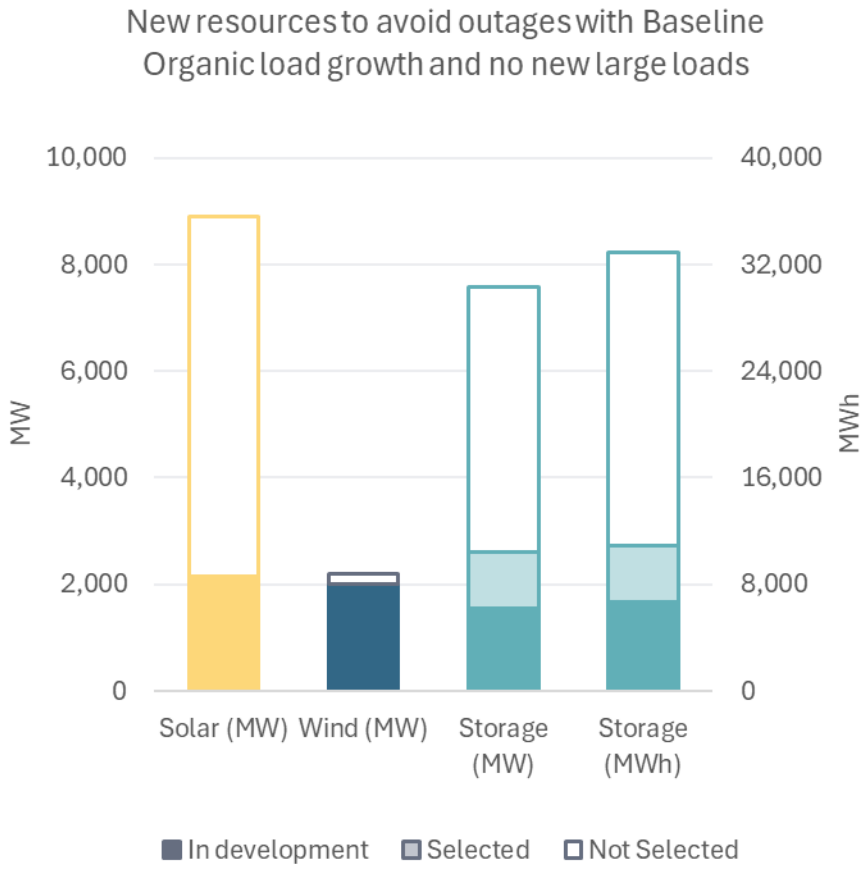
Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
Total	18,675	4,348	23%

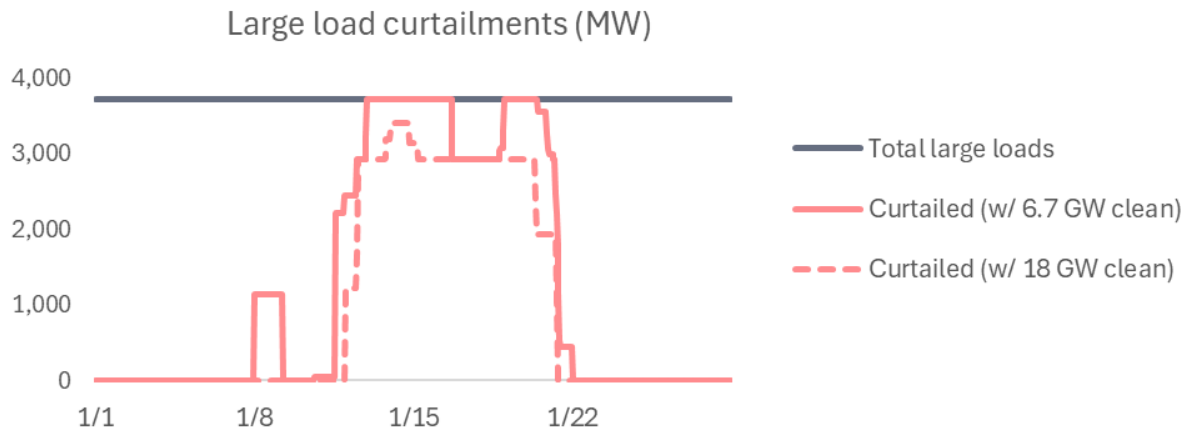
(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)



Clean resource additions and large load management in the Baseline scenario

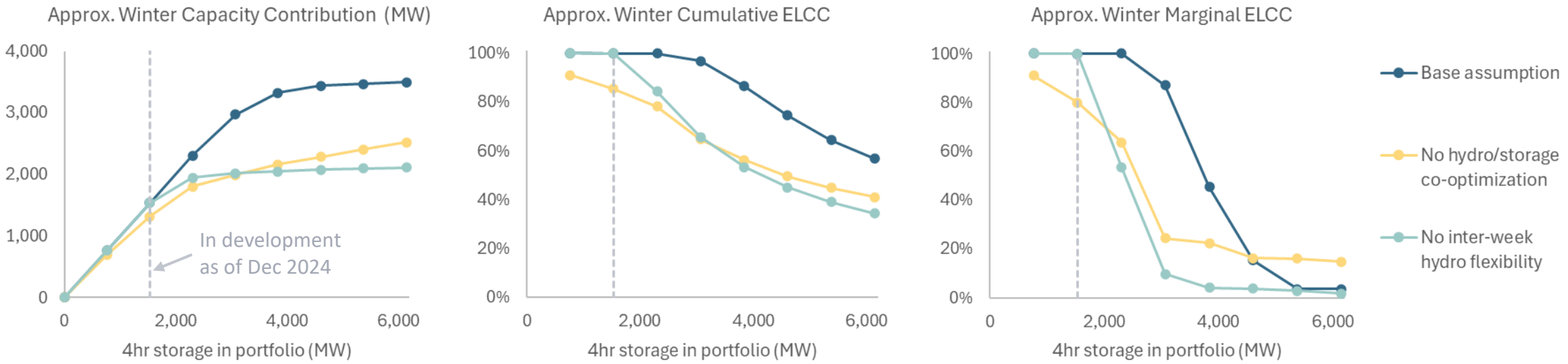


- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- Developing additional clean resources, even in very large quantities, only marginally reduces data center curtailments due to energy constraints



Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
  1. Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
  2. Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



Notes:

- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

Near-term opportunities identified to support regional RA

Policy

- **Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages**

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- **Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits**



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

Thank you!

For more information, contact:

elaine@sylvan.energy

SYLVAN ENERGY ANALYTICS

EXHIBIT 132

Department of Energy
Washington, DC 20585

Order No. 202-25-13

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[6]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[9] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

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[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[17] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[18]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[19] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[20] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

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[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[14] *Id.* at 2.

[15] *Id.* at 7.

[16] *Id.* at 9.

[17] *Id.* at 7, 9.

[18] *Id.*

[19] *Midcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).

[20] *Id.* P 84.

[21] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[22] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[22] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[23] *Id*.

[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[25] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[26] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 133

Department of Energy
Washington, DC 20585

TransAlta Centralia Generation LLC,
GridForce Energy Management, LLC, and
Southwest Power Pool, Inc. Western RC
Regarding the TransAlta Centralia Generation Facility

Order No. 202-26-44

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Northwest assessment area[3] due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation Facility (Centralia) is an electric generating facility in Centralia, Washington. Centralia is owned and operated by TransAlta Centralia Generation LLC (TransAlta). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[4] Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation based on a 2011 Washington law[5] and a subsequent

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] The terms "area" and "region" are used interchangeably herein.
[4] U.S. Energy Info. Admin., *Form EIA-860 detailed data with previous form data (EIA-860A/860B)*, https://www.eia.gov/electricity/data/eia860/ (click "2025 (early release)").
[5] Coal-Fired Elec. Generation Facilities, 2011 Wash. Sess. Laws, Ch. 180, https://lawfilesext.leg.wa.gov/biennium/2011-12/Pdf/Bills/Senate%20Bills/5769-S2.pdf.

agreement between TransAlta and the State of Washington.[6] TransAlta has announced plans to convert the unit to natural gas by 2028.[7]

Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026 (Order Nos. 202-25-11 and 202-25-11B), June 14, 2026, and September 12, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the WECC–Northwest region.

Specifically, I determined that the WECC–Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.[8] I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and

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[6] *See* Memorandum of Agreement between Christine O. Gregoire, Governor, State of Washington, & Paul Taylor, President, TransAlta Centralia Generation LLC (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to Memorandum Of Agreement between Jay Inslee, Governor, State of Washington, & Bob Nelson, President, TransAlta Centralia Generation LLC (July 13, 2017), https://www.regulations.gov/document/EPA-R10-OAR-2020-0732-0010. As a coal-fired facility, it likely would be difficult for the Centralia plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. The costs and time of decommissioning a coal plant are extensive and include various components. Therefore, restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning* 9–12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf; *see also* U.S. Energy Info. Admin., *Capital Cost & Performance Characteristics for Util. Scale Elec. Power Generating Techs.* (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Nat. Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

[8] *See*, *e.g.*, *TransAlta*, Order No. 202-25-11, at 1 (Dec. 16, 2025).

businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[9] I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.[10]

My determination was based on a number of facts. First, in its 2025–2026 Winter Reliability Assessment, the North American Electric Reliability Corporation (NERC) finds that the WECC–Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[11] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year [i.e., in 2025–2026 compared to 2024–2025]."[12]

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[13] and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026."[14] E3 reported that nearly 9,000 MW of new capacity will be needed in the region by 2030, but currently only 3,000 MW of projects for new capacity are in active development.[15] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[16]

EMERGENCY SITUATION

[9] *See, e.g.*, *id.* at 1–3.

[10] *See, e.g.*, *id.* at 3–4.

[11] NERC, *2025–2026 Winter Reliability Assessment*, at 6 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[12] *Id*.

[13] E3, *Res. Adequacy & the Energy Transition in the Pac. Nw.: Phase 1 Results*, at 2 (Sep. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf. *See also id.* (listing E3's study sponsors, which include certain "regional utilities and generation owners).

[14] *Id*. at 10.

[15] *Id*.

[16] *Id*. at 2.

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28 continue, both in the near and long term.[17] The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC–Northwest region. According to the U.S. Environmental Protection Agency's data, in 2025,[18] Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In its 2025 Long-Term Reliability Assessment,[19] NERC assessed that the WECC–Northwest region is at high risk of energy shortfalls over the next five years,[20] noting that "[r]apid forecasted demand growth is driving the need for more resources" and that "[p]eriods of unserved energy are projected for both summer and winter."[21] The assessment notes that peak load in the region "is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest."[22] Additionally, while over 10 GW of new variable resources are in development, the assessment warns that "additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging."[23]

NERC's 2026 Summer Reliability Assessment (2026 SRA) classifies the WECC–Northwest region as an Elevated Risk[24] area with highest-risk conditions occurring in early evening hours (around 6 p.m.) in late summer.[25] The region faces "elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or [is] subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as

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[17] *See, e.g.*, Order No. 202-25-11 at 1.

[18] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "January, February, March, April, May, June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Centralia (3845)"; then click "Centralia (3845)"; then click "Apply Filter"; then click "Preview Data").

[19] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 7.

[21] *Id.* at 8.

[22] *Id.* at 19.

[23] *Id.*

[24] Elevated risk refers to the potential for insufficient operating reserves in above-normal conditions. NERC*, 2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] NERC*, 2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

low wind or solar photovoltaic (PV) energy conditions."[26] Under typical outage conditions the 2026 SRA forecasts reserve margins to be 25.2% and in a scenario with extreme conditions such as higher demand, outages, and derates, reserve margin is estimated to drop to 8.8%, below the 2026 SRA Reference Margin Level of 10.0%. In normal and typical outages, reserve margins in the 2026 SRA are expected to tighten compared to the 2025 SRA, partly due to net demand growth of 4.6% compared to an increase in energy availability by generation resources of 1.5%. NERC notes that "[t]hermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months."[27] In addition, NERC's 2026 SRA notes:

> WECC–Northwest: The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the 2025 SRA and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year.[28]
>
> Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins. Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability. Supply chain constraints and economic uncertainty may impact Tier 1 resources. There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

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[26] *Id*. at 2.
[27] *Id.* at 9.
[28] *Id*. at 2.

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios.[29]

On March 2, 2026, an amended preliminary injunction was issued by the U.S. District Court for the District of Oregon that imposes operational constraints on the dams that comprise the Federal Columbia River Power System.[30] The restrictions imposed by the amended preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC–Northwest assessment region.[31] The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.[32] BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.[33] Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.[34]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding."[35] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[36]

Order Nos. 202-25-11, 202-25-11B, 202-26-18, and 202-26-28 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J.

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[29] *Id*. at 36.

[30] *Nat'l Wildlife Fed'n (NWF) v. Nat'l Marine Fisheries Serv. (NMFS)*, No. 3:01-cv-00640 (D. Or. Mar. 2, 2026) (order granting amended preliminary injunction).

[31] Fed. Def. Response to Minute Order at 4–5, *NWF v. NMFS*, No. 3:01-cv-00640.

[32] *See, e.g.*, Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2582.

[33] *See* Dibble Decl. ¶ 28; *id.* ¶ 42, fig. 3.

[34] *See, e.g.*, *id.* ¶ 26; Stevenson Decl. ¶ 18.

[35] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[36] *Id.* at vii.

Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[37] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[38] In a subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[39]

In addition, President Trump issued a White House Memo that emphasized the findings of Executive Order No. 14156 stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] President Trump "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence

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[37] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[38] *Id.*

[39] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[40] The White House, *Presidential Determination Pursuant to Sec. 303 of the Def. Prod. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*, (Apr. 20, 2026), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity.

[41] *Id*.

(AI) innovation."[42] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Pursuant to section 202(c)(4)(B) of the FPA, DOE has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued availability of Centralia Unit 2 when the Secretary has determined that such continued availability will best meet the emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Centralia plant will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to national defense in the areas affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through December 11, 2026.

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[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf.

[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From September 13, 2026, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)[44] or Southwest Power Pool Western RC[45] (in its role as the Reliability Coordinator) or any successors thereto. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By September 27, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2, consistent with this Order. TransAlta shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

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[44] *See* U.S. Energy Info. Admin., *Hourly Elec. Grid Monitor*, https://www.eia.gov/electricity/gridmonitor/about (click "EIA-930A 2024 data"). On EIA-930A 2024 SCH 2, the BA Code for TransAlta Central Generation is GRID. *See also id.* (click "EIA-930 data reference tables"). On EIA-930 data reference tables, BA Code GRID is associated with Gridforce Energy Management, LLC.

[45] *See* Sw. Power Pool, Map RTO and Western RC Footprint with Planned Expansion map, https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from September 13, 2026, through December 11, 2026, with the exception of applicable compliance obligations in paragraph D.

J. TransAlta is directed to provide written notice to the Department as soon as practicable, but no later than 15 days, following the receipt of any required permits necessary to convert the facility to natural gas.

Issued in Washington, D.C. on this 11th day of September, 2026.

Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Washington Utilities and Transportation Commission
Chair Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl

EXHIBIT 134

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-25-11

MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

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Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, the State of Washington, by and through the Washington State Attorney General, Nicholas W. Brown, moves to intervene and for a stay, and requests that the Department of Energy ("DOE") grant rehearing of Order No. 202-25-11 (December 16, 2025) (the "Order"), attached hereto as Exhibit 1.

I. INTRODUCTION

For well over a decade, the State of Washington and TransAlta Centralia Generation LLC have worked to implement a carefully orchestrated agreement transitioning TransAlta's aging Centralia Coal Plant ("TransAlta Centralia" or "Centralia") away from coal by December 31, 2025. Rather than shuttering Centralia, however, TransAlta plans to reengineer the plant as a natural gas facility, significantly reducing its pollution load to the surrounding environment and significantly increasing both its utility and capacity for servicing the region's power needs. DOE's Order issued mere days before the final cessation of coal operations to transition to gas—commands Centralia to continue its outdated life as a coal plant throws these efforts into chaos, all for reasons that defy both the law and common sense.

DOE should immediately withdraw the Order. As set out below, DOE's Order is unlawful, internally inconsistent, misguided, and based on incorrect assertions about the

Northwest's power infrastructure and operation. DOE's assertions of unfettered authority to usurp state and regional power planning based largely, if not entirely, on generalized long-range concerns directly conflict with the Federal Power Act. That Act, confirmed by decades of DOE's own exercise of authority under the Act, expressly limits DOE's authority to *actual* emergency situations involving war or the sudden and unexpected loss of power. Neither situation exists here. DOE's Order renders Congress's clear guardrails on this power effectively meaningless.

It also does so for reasons untethered from any actual immediate or even long-range problem with the Pacific Northwest's grid. DOE's order presents no legitimate factual basis—let alone substantial evidence—to support its claim that maintaining Centralia as a coal-fired facility is necessary to "meet" any emergency. In fact, DOE's Order is detrimental to the public interest by undermining the very grid stability it purports to protect in a way that will be enormously detrimental to the Northwest's rate payers. In doing so, DOE both misreads and misrepresents the sources it cites as support for an emergency—to the point that DOE's Order can only be explained as aimed to benefit the coal industry rather than at any true "emergency" in the Northwest.

Even putting aside the Order's failure to comply with the Federal Power Act's threshold limitation on emergency use, the Order is arbitrary and capricious and contrary to law. It fails to properly identify or clarify the appropriate entities that have any authority to direct TransAlta Centralia's operation, fails to comply with section 202(c)'s directives to "best" meet the emergency and public interest, and is internally inconsistent, arbitrary, and unlawful in its statement that "continuous operation" is necessary. More than that, the Order

throws TransAlta Centralia's planned upgrades in power capacity and functionality into chaos, in direct conflict with the region's *real* energy needs in 2028.

For these, and a host of other reasons detailed below, DOE should withdraw the Secretary's Order immediately.

II. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

As set out in detail in Section VI below, Washington submits the following statement of issues and specifications of error:

A. The Order is arbitrary, capricious, and contrary to law because section 202(c) and DOE's implementing regulations do not authorize emergency actions based on hypothetical scenarios, long-term forecasts, and/or generalized, unsupported statements about the nation's energy system – the only basis for this Order. Section 202(c) applies only in cases of wartime or actual emergencies involving unforeseen and imminent losses of power. DOE's regulations and past practice reflect that understanding. DOE's Order deviated from it. Further, the DOE Secretary does not have the discretion to bypass these statutory and regulatory limits. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970). *See infra* § VI.A.; Ex. 35 at 29-31 (States' Request for Rehearing, August 6, 2025).

B. The Order is arbitrary, capricious, and contrary to law because:

- It seeks to do that which Congress has expressly reserved to states and regional planning authorities: address generalized short- and long-term resource adequacy concerns. Section 202(c) does not grant DOE the regulatory authority over resource adequacy, allow DOE to issue orders based on *future* energy needs, or provide a mechanism for DOE to advance the President's policy preference for coal. Any finding otherwise is an absurd construction of the Federal Power Act that does not survive scrutiny, *Armstrong Paint & Varnish Works v. Nu-Enamel Corp.*, 305 U.S. 315 (1938), especially given that the Order springs from "an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. EPA*, 597 U.S. 697, 724-25 (2022) (cleaned up); 16 U.S.C. § 824(a). *See infra* § VI.B; Ex. 35 at 31-34.

- It was issued pursuant to an unlawful "protocol" and methodology for section 202(c) orders. That protocol, and DOE's Order here, is inconsistent with existing regulations and was not developed after public notice and an opportunity to comment. DOE's regulations and past practice direct a case-by-case analysis of specific, temporary shortages in particular situations, considering the imminent projected load and power sources in a given region, and based on a detailed application. *See* 10 C.F.R. §§ 205.371, 205.373, 205.375; *see generally* §§ 205.370 - 205.379. Here, DOE issued this Order *sua sponte*, based on its flawed methodology that has never been subjected to public comment, and on long-range supply and demand forecasts or hypothetical future events. *See* Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025); 5 U.S.C. §§ 553, 706; *Shalala v. Guernsey Mem'l Hosp.*, 514 U.S. 87, 99–100 (1995); *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018). *See infra* § VI.A(2) (explaining that DOE's "emergency" finding is inconsistent with past regulations); B (explaining that DOE's current practice exceeds the bounds of section 202(c) and DOE's historical understanding); Ex. 35 at 34-38 (explaining that DOE's new standards and definition of emergency violates the APA's notice-and-comment requirement).

C. The Order is arbitrary, capricious, and not based on substantial evidence because:

- The Order relies on statements in a North American Electric Reliability Corporation ("NERC") Winter Reliability Assessment that are taken out of context and misrepresented.

- The Order relies on a PowerPoint presentation from Energy + Environmental Economics ("E3 PowerPoint") that does not describe an emergency or find that no other source could meet a potential energy shortfall. DOE also fails to examine or disclose the assumptions, data, or methods used in creating the E3 PowerPoint.

- The Order is arbitrary and capricious because DOE relied in part on its flawed methodology, published in July 2025, which suffers from numerous analytical, mathematical, and empirical flaws. DOE's methodology also ignores reasonable alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs.

- DOE failed to reasonably explain why its methodology supports issuing an emergency order here, when the methodology found the system in the Northwest was currently reliable and Washington meets DOE's reliability standard in the short and long-term.

- DOE relies on generalized and unsupported presidential statements in executive orders, which are not evidence and which direct action that violates the Administrative Procedure and Federal Power Acts.

None of these documents are reasoned, evidentiary bases to find that an emergency exists. *See* 16 U.S.C. § 825*l*(b); 5 U.S.C. § 706(2)(E); *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (same and noting that Federal Power Act orders must also be either "consistent with past practice or adequately justified"); *see also, e.g., Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962). *See infra* § C; Ex. 35 at 21-38 (explaining problems in DOE's methodology).

The Order is also arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because:

- It fails to resolve ambiguity and creates confusion with regard to the entities that have authority to order TransAlta Centralia to run. *See infra* § D(1).

- It fails to comply with section 202(c)'s requirement to craft terms that "best meet the *emergency* and serve the public interest," 16 U.S.C. § 824a(c)(1), or to examine reasonable alternatives to issuing an emergency order, *see Spirit Airlines, Inc. v. U.S. Dep't of Transp.*, 997 F.3d 1247, 1255 (D.C. Cir. 2021). Those alternatives include energy imports and exports, existing reliability planning mechanisms, or alternative energy sources. *See infra* § D.2, D.4; Ex. 35 at 22-25.

- DOE failed to consider the operational status of Centralia, its limitations to meeting peak energy needs, or its environmental and economic constraints. DOE also *failed* to consider other evidence that conflicts with its findings that an emergency exists, including state regulators' response and assessment of the NERC Winter Reliability Assessment and E3 PowerPoint, the availability of hydroelectric power, existing capacity resources in the WECC Northwest, or utilities' Integrated Resource Plans. *See infra* § C.4, D.2, D.4. E.1.

- In *stating* a need for "continuous operation," DOE fails to account for the fact that Centralia's power has no current customers or section 202(c)'s temporal and environmental limitations. *See* 16 U.S.C. § 824a(c)(2). *See infra* § D.3.

- It *risks* destabilizing the grid it purports to protect because it interferes with and disrupts utilities' existing resource plans. *See infra* §§ D.3-4, E.

- It pursues an extra-statutory motive of preserving aging and uneconomic coal-fired *power* plants at consumer expense, which contradicts the Federal Power Act's express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Order also establishes an unlawful preference for coal-fired power over other alternatives, including but not limited to natural gas, in violation of the Federal Power Act's prohibition on undue discrimination or preference. The Administration's energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep't of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022); *see infra* § D(5); Ex. 35 at 27-29.

D. The Order is arbitrary, capricious, and contrary to law because DOE failed to consider important factors affecting the public interest or explain why its order serves the public interest notwithstanding these factors. Specifically, DOE's order undermines the Northwest's energy market, leading to increases in electricity rates and harm to consumers. The Order could force curtailment of cheaper and abundant hydropower. It will also derail the long-planned conversion of TransAlta Centralia to natural gas, which utilities have determined to be the best way to meet the region's future energy needs. Running Centralia will also result in significant air pollution, harming human health and the environment. 16 U.S.C. § 824a(c)(1); *Michigan v. EPA*, 268 F.3d 1075, 1981 (D.C. Cir. 2001). *See infra* § E.

E. In failing to assess the environmental consequences of a major federal action significantly affecting the human environment, the Order violates the National Environmental Policy Act. 42 U.S.C. § 4321, *et seq*.

III. MOTION TO INTERVENE AND INTERVENOR'S INTEREST

The State of Washington moves to intervene in this proceeding and become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. *See* RCW 43.10.030(1). *See also City of Seattle v. McKenna*, 172 Wash. 2d 551, 259 P.3d 1087 (2011) (noting that RCW 43.10.030(1) grants the Attorney General discretionary authority to act in any forum "on a matter of public concern" (internal quotations and citations omitted). The TransAlta

Centralia Plant is located in the State of Washington, and the State is aggrieved by the Order in several ways.

First, Washington has a direct contractual interest in the retirement of Centralia on December 31, 2025. In 2011, the Washington Legislature passed the Coal-Fired Electric Generation Facilities Bill, SB 5769. S.B. 5769, 62nd Leg., (Wash. 2011). That Act directed Centralia to comply with the state's greenhouse gas emission performance standards by the end of 2020 for its first boiler and the end of 2025 for the second. RCW 80.80.040(c). It also directed the Governor to enter into a Memorandum of Agreement with the owners of Centralia. RCW 80.80.100. The State and TransAlta signed the Memorandum of Agreement in 2011, which was amended in 2017 to specify that Centralia could continue to generate power, so long as it was not coal-fired power. Ex. 5 (2011 MOA); Ex. 6 at section 1 (amending Subsection D(5) of the MOA) (2017 MOA Amendment).

The Memorandum of Agreement required Centralia to permanently cease coal power generation from one boiler in 2020, and the other boiler in 2025. Ex. 5; Ex. 6. In exchange for that commitment, the State of Washington confirmed that the facility met the greenhouse gas emissions performance standards and other environmental requirements of the State, guaranteed the ability of TransAlta to enter into long-term power contracts for the sale of electricity from Centralia, and promised to maintain sales and use tax exemptions for the plant. Ex. 5. The State of Washington kept those promises, sacrificing tax revenue and granting TransAlta flexibility with regard to operational controls in exchange for Centralia ceasing coal operations by the end of 2025. *See, e.g.*, RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax);

RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and remediation costs in rates).[1] Because the Order deprives Washington of the benefit of its bargain under the Memorandum of Agreement, Washington suffers distinct harms as a result of the Order.

Second, Washington has a direct regulatory interest in Centralia's retirement by the end of 2025 because continued coal-fired operations will directly violate state law as well as a regulatory order issued by the Department of Ecology. Centralia is subject to Washington's emissions performance standard (EPS) for baseload electric generation in the state, RCW 80.80.040. The EPS is essentially a carbon intensity standard, limiting the volume of greenhouse gas emissions that an electric generating facility may emit per megawatt-hour of power produced. RCW 80.80.040(1), (3). This standard cannot generally be met by coal-fired plants without employing carbon sequestration technology.[2] The application of this standard was delayed for TransAlta until the scheduled shutdown of its two boilers at the end of 2020 and 2025. RCW 80.80.040(3)(c) ("A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year

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[1] *See e.g.* RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax); RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and remediation costs in rates).

[2] The emission performance standard is currently set at 876 GHG/MWh. WAC 173-407-130 (setting forth EPS standard in Ecology's EPS rules). *See* RCW 80.80.040(1)(providing procedures for setting standard); RCW 80.80.050 (setting out Washington Department of Commerce's role to set standard); WAC 194-26-020 (Washington Department of Commerce setting standard).

prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025: [referencing process for setting standard].").

TransAlta relied on the 2025 retirement of its last coal-fired boiler as its means of complying with Washington's emissions performance standard. Ex. 7 at 2, §D(a)(1) (2011 BART Order) ("The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the [coal-fired] units."). Further, the Washington Department of Ecology issued Centralia a regulatory order imposing Best Available Retrofit Technology ("BART") requirements pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART order specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition; Ex. 8 at 3, condition 3 (2020 BART Order, Revision 2). Thus, continued operations of TransAlta's coal-fired boilers, without substantial investment in new emissions-lowering technology, will directly violate Washington's Emission Performance Standard and BART order.

Third, Washington residents will suffer health and environmental harms because of the Order, with costs to the State resulting from the heightened burden on state-provided insurance and public hospitals. As detailed below in Section IV(H)(2), continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonians' health imposing direct harms on the State and its agencies, and impair visibility at

Washington's iconic natural areas such as the Mount Rainer National Park. Ex. 10 at ¶ 7 (Declaration of Gary Palcisko).

Fourth, these environmental harms will frustrate the Washington State's regulatory interests, harm the State's public trust resources, and pose a financial burden to the State. For example, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12 (Top 10 Stationary Sources of GHG Emissions in WA, 2022); Ex. 13 (Top Washington Greenhouse Gas Emissions Sources, 2023). By mandating the continued operation of the Centralia Coal Plant, the Order will make it harder for Washington to meet its statutory greenhouse gas emissions reduction requirements. RCW 70A.45.020. And continued burning of coal will also hinder Washington's investigation and cleanup of the site under the Model Toxics Control Act (MTCA). *See* Ex. 52 at ¶ 16 (Declaration of Thomas Middleton). Under MTCA, the Washington Department of Ecology is responsible for investigating contamination, developing cleanup action plans, and identifying potentially liable parties (PLPs) for sites contaminated with hazardous substances. *Id.* at ¶ 4-14.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above MTCA cleanup levels. *Id.* at ¶ 7. The Order will prolong the contamination of the Site, exacerbating the time and resources the State must expend to investigate and plan its cleanup. *Id.* at ¶ 14. The Order will also cause continued aerial emissions of hazardous substances, which have the potential to settle on and contaminate thousands of properties and create thousands of potentially liable parties under MTCA. *Id.* at ¶ 14. Determining liability and cleanup responsibility for so many sites is resource-intensive for the State. *Id.* Finally, the Centralia

Coal Plant uses settling ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15. The Order will require TransAlta to continue using the settling ponds, preventing the Washington Department of Ecology from performing cleanup of the ponds, and potentially posing risks related to groundwater contamination. *Id.*

Fifth, Washington's electricity grid will be less reliable because of the Order. In addition to the direct interest in grid reliability to power state buildings, public schools, and hospitals, Washington has a regulatory interest in maintaining grid reliability.[3] Centralia experiences extended periods of non-operation. In the years 2023-2025, the Centralia Plant Unit #2 shut down 29 times, 25 of which were forced outages. Ex. 11 at ¶ 7 (Declaration of Clinton Lamoreaux). Additionally, when coal-powered generation facilities do shut down, they have a longer start-up time than natural-gas-powered facilities, which makes them less responsive to fluctuating energy demands. Ex. 14 (Owen Comstock, *About 25% of U.S. power plants can start up within an hour,* U.S. ENERGY INFO. ADMIN., November 19, 2020). This is especially true for "cold" startups, where the facility must start up after an extended period of nonactivity. Cold startups take longer than startups following a briefer outage where the facility components are still warm from recent operation. Ex. 11 at ¶ 8. It took Centralia anywhere from 11 to 18 hours to reach its operational capacity during the six cold startups

[3] The Washington Utilities and Transportation Commission (UTC) is tasked with regulating IOUs such that any services rendered are "adequate and efficient," RCW 80.28.010(2), (11); RCW 19.405.080(2)(a) (reporting requirements concerning reporting on meeting load, reliability standards, and resource adequacy); RCW 80.28.130 (granting UTC authority to order an electric utility to make improvements to their system to "secure adequate service or facilities").

from the fourth quarter of 2024 through the third quarter of 2025. *Id.* Plus, because Centralia is likely overdue for maintenance, it could face more frequent shutdowns than in previous years. Ex. 11 at ¶ 10-11.

This will be exacerbated by the apparent staffing shortages Centralia faces. Ex. 11 at ¶ 12. Finally, aside from in limited circumstances, Washington utilities are prohibited from purchasing power from coal plants after December 31, 2025. RCW 19.405.030. Because of these frequent shutdowns, the length of time needed to start up the plant, the uncertainties around maintenance and staffing, and the legal barriers to purchasing power from Centralia, coal operations at Centralia are less reliable, efficient, or economical than other alternatives. However, the Order will force ratepayers to pay for Centralia's operations rather than investing in alternatives, resulting in a loss of capacity and flexibility for Washington's electricity grid.

Sixth, Washington agencies, households, and businesses will likely pay higher electricity bills because of the Order, and Washington has a regulatory interest in keeping electricity rates fair and affordable.[4] Under the most recent Power Purchase Agreement (PPA) which expired on December 31, 2025, the price from Centralia's coal is significantly higher than the wholesale energy market price, at $62.04 per MWh versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15 (Declaration of Callahan Moriyasu). It is also unclear whether Centralia will be safe to operate. Recent inspections and the most recent quarterly

[4] *See e.g.* RCW 80.28.010(1) (The UTC is also tasked with regulating IOUs in the public interest and ensuring rates for "any service rendered" are "just, fair, reasonable, and sufficient."); The Clean Energy Transformation Act requires utilities to achieve targets at the "lowest reasonable cost," RCW 19.405.040(6)(a)(i), -.050(3)(a),-.060(1)(c)(ii), -.080(2)(b).

report indicate that Centralia's pollution control technology requires maintenance or repairs. Ex. 11 at ¶ 10-11. Further, recent staffing shortages may have led to the violations that Centralia was noticed for in December. Ex. 11 at ¶ 12. TransAlta will likely have to expend resources to quickly hire and train new staff to operate the facility. TransAlta will no doubt seek to recover those costs through its rates. Although the precise amount of the costs is not yet known, by ordering the continued operation of TransAlta's Centralia Coal Plant, the Order ensures that Washington ratepayers will see unreasonably higher electricity bills, in contradiction with Washington's statutory mandate to secure rates that are "just, fair, reasonable, and sufficient." RCW 80.28.010(1).

IV. BACKGROUND

A. The Long-Planned Retirement of TransAlta's Coal-fired Units

1. The TransAlta Centralia coal-fired power plant

The Centralia generating plant is a coal-fired power plant located just east of Centralia in Lewis County, Washington that is owned and operated by TransAlta Generating LLC ("TransAlta Centralia" or "Centralia"). Centralia was built in the late 1960s and originally consisted of two coal-fired boilers. Ex. 15 (The Daily Chronicle, *Plant Job Underway*, June 14, 1968); Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). The first boiler went into operation in 1971 and the second in 1972. The first boiler, known as "Unit 1" was retired in 2020, and the second boiler, "Unit 2," was scheduled to retire by December 31, 2025. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). Centralia currently has a nameplate generating capacity of 729.9 MS and a net capacity of 670 MW. Ex. 18 at "Operating" tab, row 5359, plant name "TransAlta Centralia Gen LLC" (U.S.

Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860).

TransAlta Centralia generates electricity by combusting pulverized coal in a boiler to generate pressurized steam to drive a turbine. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). This produces emissions of sulfur dioxide (SO2), oxides of nitrogen (NOx), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants including mercury. Ex. 17 at 2. TransAlta Centralia has been one the largest historical sources of NOx and SO_2 in Washington, annually emitting over 5,000 tons of NOx and 1,500 tons of SO2 in 2011–18. Ex. 19 at 74 (2022 Visibility SIP). Since closure of Unit 1 of Centralia in 2020, emissions have decreased by approximately half, but these emissions still rank amongst the highest in the State for a single source. Ex. 19 at 74. TransAlta Centralia is also the largest single stationary source of greenhouse gas emissions in the state with, over 3.9 million metric tons of annual CO2 emissions in 2022, and over 4.5 MMT CO2 in 2023. Ex. 12; Ex. 13. These pollutants have significant adverse health and environmental impacts. Ex. 10 at ¶¶ 7–14. TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural areas, including at Mount Rainer National Park, located only 50 miles from the plant. Ex. 19 at 172 (2021 Visibility SIP).

2. Agreement reached over a decade ago to transition TransAlta away from Coal

In 2011, Washington, TransAlta, environmental groups, and the local community worked together to establish a plan to transition Centralia away from coal towards cleaner fuels. Ex 20 (TransAlta Power Plant, Department of Ecology). The Washington Legislature

passed the Coal-Fired Electric Generation Facilities Act, Engrossed Second Substitute S.B. 5769, Ch. 180, Wash. Laws of 2011, requiring TransAlta Centralia to comply with the state's greenhouse gas emission performance standards beginning at the end of 2020 for Unit 1 and the end of 2025 for Unit 2. Ch. 180, Wash. Laws of 2011 § 103; RCW 80.80.040(1), (3)(c). The Washington Department of Ecology then issued a Best Available Retrofit Technology (BART) order to TransAlta pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART Order recognized that TransAlta Centralia would comply with the greenhouse gas emissions standards through the phased retirement of its coal-fired boilers. Ex. 7 at 2 §D(a). The BART order further specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition 4; Ex. 8 at 3, condition 3. By the end of 2011, the State and TransAlta signed a Memorandum of Agreement, as required by SB 5769, in which TransAlta formally agreed to the phased shutdown of both coal-fired boilers by the end of 2020 and 2025 respectively. Ex. 5 at 1 (Recital D) (TransAlta agreed to "permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025.").

In 2017, the MOA was amended to, among other things, change the scope of power generation activities that TransAlta Centralia was required to cease in 2020 and 2025. While the 2011 MOA originally requiring cessation of all "power generation operations" in the two boilers, the amendment signed in 2017 narrowed this to requiring cessation of only "*coal-fired* power generation operations" of each boiler. Ex. 6 at Section 1 (amending Subsection D(5) of the MOA). This would allow TransAlta to continue generating electricity at Centralia upon

the conversion of its boilers to cleaner fuels such as natural gas. Ecology's 2020 revision to TransAlta's BART Order reflected this, acknowledging the possibility of continued operation of the Centralia plant with cleaner fuels. Ex. 9 at 3 (2020 Bart Order TSD at 3) ("If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.").

3. TransAlta coal-to-gas conversion project

TransAlta has now developed a plan to convert TransAlta Centralia to natural gas.[5] On December 9, 2025, TransAlta announced a long-term agreement with Puget Sound Energy to perform a coal-to-gas conversion on Centralia's Unit 2 facility with a planned contracted capacity of 700 MW to deliver power to Puget Sound Energy ("PSE") through 2044. Ex. 20 at 1 (Press Release from TransAlta dated Dec 9, 2025,). TransAlta expects to invest approximately $600 million in capital expenditures in the project, and is targeting late-2028 to begin commercial operations, which will reduce emissions by approximately 50%. *Id*. TransAlta's President and Chief Executive Officer, John Kousinioris explained that TransAlta was "pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers." *Id*.

[5] The State cites to the announced conversion to natural gas in keeping with industry practice of including announced planned additions to generation. To finalize those plans, TransAlta will need numerous permits and approvals from the State for the conversion to occur. Nothing within this filing should be interpreted as any agency or arm of the State presupposing or otherwise commenting on the merits of those permits or approvals.

After conversion, TransAlta Centralia will operate only when there is high demand, with the majority of its hours of operation expected to be at half load (~350 MW) or at minimum stable generation load (~190 MW), but with the ability to quickly ramp up to high loads when needed by the grid. Ex. 21 at 1-1 (December 2025 TransAlta PSD Permit application). Conversion of Centralia to natural gas will dramatically reduce TransAlta Centralia's emissions of almost all pollutants, including large and fine particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), lead, and carbon dioxide (CO_2). Ex. 21 at 3–4 (Table 3-1).

B. Washington Recently Assessed and Confirmed Resource Adequacy in Our Region

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Indeed, in its July 2025 resource adequacy report, DOE wrote, "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level….entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience." Ex. 4 at i (DOE 2025 Resource Adequacy Report).

In this, DOE is correct, and Washington's Utilities and Transportation Commission does precisely that, and held three meetings in 2025 in conjunction with Washington's Department of Commerce to consider information from industry experts from Washington utilities, regional planning organizations, transmission operators, reliability experts, and the public. Ex. 53 ¶¶ 4-6 (Declaration of Brian Rybarik, Chair of the Washington Utilities and

Transportation Commission). As a matter of best practice, resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country. *See* Ex. 55 (*Best Practices in Integrated Resource Planning,* Synapse Energy Economics & Lawrence Berkeley National Laboratory (Nov. 2024). Following this best practice, the Washington Utilities and Transportation Commission, and the November 2025 Winter Readiness Resource Adequacy meeting, Washington planners invited presentations from NERC, the Western Electricity Coordinating Council, Arne Olson, the author of the E3 PowerPoint, as well as from Washington utilities. Ex. 22 (Nov. 19, 2025 Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting) (The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

By contrast, DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. And, as far as Washington can determine, DOE failed to attempt consultation with any of the local, regional, or national reliability experts in issuing its emergency order regarding TransAlta. Using the information from the entities responsible for maintenance and operation of the grid, in November 2025, Washington's utility regulators confirmed the adequacy of generation resources for our state's electricity grid. Ex. 22. In a letter summarizing the September meeting, Washington state utility regulators assessed resource adequacy as follows:

> Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.

> However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

Ex. 22 at 1–2. Washington's utility planners also considered Washington's winter readiness, reporting that:

> Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Counsel, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions with winter. Extreme weather poses and elevate risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures for firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.
>
> At the November 4 Meeting, the Bonneville Power Administration and utilities shared steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sount Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

Ex. 50 at ¶ 10 (Declaration of Andrew Reeves); Ex. 50-4 (Summary of 2025 Winter Preparedness Meeting). The Chair of the Washington Utilities and Transportation Commission reviewed DOE's emergency order in light of his industry experience, his review of resource adequacy plans filed with the Commission, the information from national, and

regional experts and concluded, "I do not find that DOE's Order's conclusions that an energy emergency exists in the coming winter months credible, nor do I agree that action under the DOE order (keeping the Centralia coal plant available) will assist in solving the unlikely extreme conditions that could lead to an energy emergency." Ex. 96 at 3.

Tellingly, DOE's flawed July 2025 Resource Adequacy Report found that even assuming all firm planned retirements, including TransAlta, and assuming minimal resource additions the Washington region faces no significant long term reliability risk:

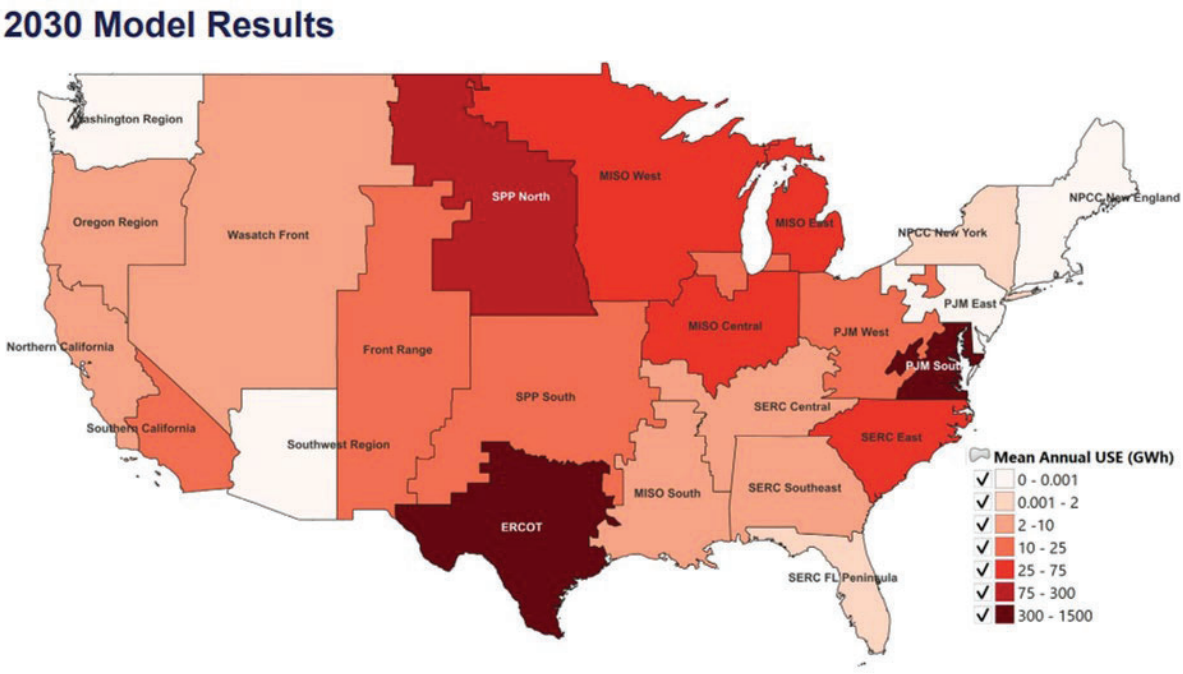


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Ex. 4 at 6 (DOE 2025 Resource Adequacy Report). The deep methodological flaws in DOE's report are discussed at greater length below. But for the purposes of this review, all information agrees; even under DOE's worst case scenario analysis, the Washington region is one of the few regions in the country in which reliability is not a concern before 2030. The

reality is that there is no reasonable dispute that there is no energy emergency in the Washington to justify an order to keep TransAlta available as a coal plant.

C. DOE's Historical Use of Section 202(c)

Prior to 2025, DOE has used section 202(c) sparingly, and only in response to concrete, particularized emergencies subject to limitations to ensure that DOE's reach extends no further than necessary to address the emergency at hand.

As discussed below, section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). The law also effectively immunizes noncompliance with "any Federal, State, or local environmental law or regulation" associated with an action or omission necessary to comply with a 202(c) order." 16 U.S.C. § 824a(c)(3). However, the Act also imposes significant limits on any 202(c) order that "may result in a conflict" with a pollution control requirement, including limiting the hours of operation of such facilities and limiting the order to 90-days, with extension possible. 16 U.S.C. § 824a(c)(2) and (4).

That authority originated as a wartime power granted in 1935 to what was then the Federal Power Commission in order to guard against energy-related shortages that were viewed as hampering national security during World War I. *See* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 798-802 (2025). The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II. *See id.* at 803. Section 202(c) orders were issued repeatedly during the war, primarily

to order interconnection between utilities, but the provision was rarely invoked once the war ended. These "interconnection" orders between utilities were more necessary at a time when America's electric grid was more fragmented, monopolized, and less diversified than it is today. *Id.* at 802-804. Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time. *Id.* at 801-802. A number of organizational changes ensued in the decades following the War and the provision's authority eventually came to rest with the Secretary of Energy. *Id.* at 803-04; 42 U.S.C. § 7151(b).

DOE has historically invoked its 202(c) emergency sparingly to respond to clear-cut and imminent emergencies to avoid immediate significant blackouts. *See* Rolsma, *supra*, at 805-509. Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of 2024, DOE appears to have used section 202(c) twenty times, not counting amendments and extension orders, prior to 2025. *See* Ex. 23-1 through 23-20. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000. Ex. 23-1 (DOE, *Order Pursuant to Section 202(c) of the Federal Power Act*, December 14, 2000). Since then, by far the most common usage—comprising 14 of 20 instances—has been in response to extreme weather events such as hurricanes, extreme cold, and extreme heat. *See* Exs. 23-2 and 23-3 (DOE Order Nos. 202-05-1 & -2, September 28, 2005) (response to Hurricane Rita); Ex. 23-4 (DOE Order No. 202-08-1, September 14, 2008) (Hurricane Ike); Ex. 23-5 (DOE Order No. 202-20-1, August 27, 2020) (Hurricane Laura); Ex. 23-13(DOE Order No. 202-24-1, October 9, 2024) (Hurricane Milton); *See* Ex. 23-7 (DOE Order No. 202-21-1, February 14, 2021) (extreme cold); Ex. 23-11 (DOE Order No. 202-22-3 (December 23, 2022)

(extreme cold); Ex. 23-12 (DOE Order No. 202-22-4, December 24, 2022) (extreme cold); Ex. 23-6 (DOE Order No. 202-20-2, September 6, 2020) (extreme heat in California); Ex. 23-8 (DOE Order No. 202-21-2, September 10, 2021) (extreme heat, wildfires and drought in California); Exs. 23-9, 23-10 (DOE Order Nos. 202-22-1 & 2, September 2022) (same).

In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both. And, in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements. DOE also limited the duration of those orders to the minimum period necessary to address the emergency, typically lasting for a period of days to weeks. *See* Rolsma, at 839-42 tbl.1 (chronicling all section 202(c) orders issued "after dissolution of the Federal Power Commission").

The typical process for issuing a section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes including demand response mechanisms are incapable of addressing, though they may be issued by DOE unprompted as well. *See* 10 C.F.R. § 205.370. Applications for section 202(c) orders made by outside entities are to include specific details to "be considered by DOE in determining that an emergency exists" and the appropriate intervention. 10 C.F.R. § 205.373. This includes "[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the

emergency," "[a] description of the situation and a discussion of why this is an emergency, . . . includ[ing] any contingency plan of the applicant and the current level of implementation," and "[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts." 10 C.F.R. §§ 205.373(a)-(o).

Prior to 2025, DOE has used section 202(c) on only three occasions to delay the retirement of generation facilities[6]. These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close. Ex. 23-1 at 1 (DOE Order No. 202-05-3, December 20, 2005) (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24). The D.C. Public Service Commission, supported by the local utility,

[6] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.

PEPCO, explained that the Mirant facility directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[7] *Id*. at 2. Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C. *Id*. at 3–4. Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility. *Id*. at 5–8. The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service. *Id*. at 10–11.

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from ENERGY. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under

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[7] This incident eventually led to the statute's 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a section 202(c) order, leading the statute to read as it does today. *See* Rolsma, *supra*, at 806-08 (citing DEP'T OF ENERGY, ORDER NO. 202-05-3, December 20, 2005); 16 U.S.C. § 824a(c)(3)-(5).

repair. And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials. Ex. 24 (Letter Request of Grand River Dam Authority). The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first. Ex. 23-15 at 2 (DOE Order No. 202-17-1). The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes." *Id*.

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond. Ex. 23-16 at 1 (DOE Order No. 202-17-2). DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes." *Id*. at 2. DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order. Ex. 23-17 at Summary of Findings (DOE Order No. 202-17-4, Sept. 14, 2017). In its extension order, the Department continued to limit dispatch of the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units. Ex. 23-17 at 2 (DOE Order No. 202-17-4, September 14, 2017).

D. White House Strategy to Prop Up the Coal Industry

Since the 2025 Inauguration, the White House and DOE have sought to radically transform how section 202(c) of the Federal Power Act is applied—departing in almost every material respect from the longstanding approach described above. On January 20, 2025, his first day in office, President Trump issued Executive Order 14156, titled "Declaring a National Energy Emergency." 90 Fed. Reg. 8433. That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.[8] *See Id*. (providing no factual support for claimed emergency).

On April 8, 2025, President Trump issued Executive Order 14262, titled "*Strengthening the Reliability and Security of the United States Electric Grid*." 90 Fed. Reg. 15521 (April 14, 2025). The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective. Ex. 56 (New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*, April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025). This event, and the related Executive Orders, are part of several in a series of public

[8] That declaration is subject to a pending legal challenge by multiple states. *See* Complaint, *Washington v. Trump*, NO. 2:25-cv-00869 (W.D. WA May 9, 2025).

actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure." Executive Order 14262 at section 3(a). It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- of a process by which the developed methodology and any analysis results are regularly assessed; and,
- of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.

Executive Order 14262 section 3(b), (c).

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14156, *Declaring a National Energy Emergency*. Executive Order 14262, § 2. In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. President Trump has declared eight national emergencies in the first seven months of 2025 alone, and has invoked this power more in the first 100 days in office than any other President in modern

history. *See* Ex. 57 (Brennan Center for Justice, *Declared National Emergencies Under the National Emergencies Act*).

E. DOE's Section 202(c) Orders Preventing the Retirement of Fossil Fuel Power Plants Issued in 2025

Since January 20, 2025, DOE has issued orders to eight facilities under section 202(c) of the Federal Power Act, a sharp uptick from the less than one order per year issued on average from 2017-2024. *See* Ex. 23 (2025 DOE 202(c) orders). In late May 2025 DOE issued a pair of section 202(c) orders requiring fossil fuel generation facilities in Michigan and Pennsylvania that were each slated to retire the very next business day to remain on-line. Ex. 27 (U.S. Dep't of Energy, Order No. 202-25-3 (Campbell Order); *See* Ex. 28 (U.S. Dep't of Energy, Order No. 202-25-4 (Eddystone Order). Both the Campbell and Eddystone Orders have now been extended twice. Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025). These orders represent a marked shift in how section 202(c) has historically been used.

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any imminent emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy's service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE's

order for 90 days would approach $100 million. *See, e.g.*, Ex. 29 (Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025). Consumers Energy disclosed that continued operation of the plant in the first five weeks since the Order was issued resulted in a net financial impact of $29 million. *See* Ex. 30 (CMS Energy Corp., Quarterly Report (Form 10-Q), July 31, 2025); *See also* Ex. 31 (NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target*, June 16, 2025).

F. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) "Reliability Interventions"

On July 7, 2025, DOE published its "Report on Evaluating U.S. Grid Reliability and Security," which set forth the methodology and reliability standard that the Executive Order on grid reliability had mandated. Ex. 4 (U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, July 2025). DOE published this report without proving any public notice or comment period and without any apparent consultation with any grid operator or State. *See* Ex. 4 at i (acknowledging lack of data from regional and utility levels). Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE's analysis. Nor has DOE opened any administrative proceeding to otherwise involve the public in DOE's methodology and DOE has not published the Report in the Federal Register.

Nevertheless, DOE confirmed in the report that it would rely on the Resource Adequacy Report to justify future section 202(c) orders, consistent with the Executive Order's mandate. *See* Ex. 4 at vi (explaining that DOE's standard will be used to "guide reliability interventions"); *id.* at 1 (emphasizing the need for DOE's "decisive intervention" in energy

markets); *id*. at 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT"). As explained in an accompanying fact sheet, DOE would use the methodology to "prevent [] generation resources from leaving the bulk-power system." Ex. 32 (U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid*, 2025); *see also* Ex. 33 (Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security, July 7, 2025) (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act").

Due to numerous significant flaws in DOE's resource adequacy report that render it arbitrary and capricious, a number of states including Washington submitted a rehearing request to DOE on August 6, 2025. Ex. 35 (August 6, 2025 Rehearing Request). Among other things, the rehearing request pointed out that the Report was based on flawed and arbitrary assumptions and unsupported by substantial evidence because it failed to reasonably support its load growth assumptions and arbitrarily assumed 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same period, lacked sufficient regional granularity and suffered from other analytical flaws, and established an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act. *Id*. at 18–29. In addition, the report does not point to any sudden, unforeseen, or imminent circumstances that describe an "emergency" under the Federal Power Act to justify 202(c) orders, the report fails to consider existing reliability mechanisms, intrudes on state authority over generation facilities and non-emergency resource adequacy planning, and was adopted

subject to critical procedural flaws including failing to provide public notice and comment. *Id*. at 29–39.

DOE did not respond to the critiques raised by the States and other entities of its resource adequacy report and continues to rely on the resource adequacy report to justify emergency 202(c) orders. Rather, DOE denied the States' and other entities' requests for rehearing based on its assertion that the resource adequacy report was not an "'order' by which the State AGs are 'aggrieved' within the meaning of section 313 of the FPA." 313*l*. Ex. 35-2 (2025 State AG's Request for Rehearing of DOE Report).

G. DOE's 202(c) Emergency Order to TransAlta Requiring It To Continue To Be Available as a Coal-Fired Power Plant

On December 16, 2025, DOE issued a 202(c) order to TransAlta, requiring that Centralia remain ready to run as a coal-fired power plant beyond its scheduled closure date of December 31, 2025. Ex. 1. This Order, issued only 15 days before Centralia's scheduled closure as a coal plant, directs TransAlta to "take all measures necessary to ensure that Centralia Unit 2 is available to operate" at the direction of either the Balancing Authority or Reliability Coordinators for the region—which the Order identifies as Bonneville Power Administration (BPA) and the California Independent System Operator Corporation (CAISO), respectively. Ex. 1 at 3. While this suggests that the plant should be kept on standby at the ready to run as needed, the Order also confusingly states in footnote 11 that "continuous operation is required . . . so long as Secretary determines a shortage exists and is likely to persist," to avoid the complications that could result from starting and stopping operations intermittently. Ex. 1 at 2, n. 11.

The order justifies DOE's invocation of its emergency authority under section 202(c) of the Federal Power Act due to the Secretary's determination of an "emergency situation" within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]" Ex. 1 at 1. Specifically, DOE's determination of an "emergency" is based on the NERC's 2025-2026 Winter Reliability Assessment, a September 2025 Power Point presentation on resource adequacy by Energy + Environmental Economics (E3), and DOE's July 2025 Resource Adequacy Report and two executive orders. *Id*. While the Order acknowledges that these sources found that "there is sufficient capacity for expected peak conditions," DOE asserts that there is a present emergency anyway due to an "elevated risk during periods of extreme weather." *Id*. That "elevated risk" contemplates a scenario in which, during a period of peak demand, extreme weather causes the outage of thermal power plants as well as adverse wind turbine conditions and, on top of that, similar extreme weather extends to neighboring regions so that the Northwest Region cannot import power. *Id*. The Order also cites accelerated load growth estimates out to 2030 and a shortfall in the development of adequate new capacity to meet this forecast demand. *Id* .

Finally, the Order cites the president's Executive Orders declaring a national energy emergency and on grid reliability for additional support and cites DOE's July 2025 resource adequacy report conducted under those executive orders for the proposition that "decisive intervention" to the Nation's power grid is necessary "to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation." Ex. 1 at 2-3 (citing Ex. 4).

H. Impacts of Continued Coal Operations at Centralia

1. Deferred maintenance and upgrades make running Centralia as a coal plant difficult, expensive, and less reliable

TransAlta Centralia is an old facility and has not been maintained for continued operations beyond 2025 due to its planned retirement. Moreover, in recent years Centralia has been subject to frequent forced shutdowns due to breakdowns. For example, from 2023 through 2025 Centralia shutdown 29 times, 25 of which were forced outages, for issues such as needed "tube leak repairs." Ex. 11 at ¶ 7; Exs. 11-1 through 11-11 (Centralia Plant's quarterly reports submitted to SWCCA from 2023 through 2025).

Centralia's electrostatic precipitators (ESPs) that control its coal fly ash particulate matter emissions are failing—causing the plant's plume to register opacity levels approaching its 30% permit limit, even when operating below full load. Ex. 11 at ¶¶ 9–10; Ex. 11-12 (photograph of opacity readings on Oct. 23, 2025). In addition, Centralia has not been able to maintain the required control of its carbon monoxide (CO) emissions. Ex. 11 at ¶ 11; Ex. 11-3 (TransAlta Most Recent Quarterly Report). As described by TransAlta in its 2022 U2 Boiler Tune-up Report, this could be due to air leakage associated with cracks and holes that is impairing operation of fan components. Ex. 11 at ¶ 11; Ex. 11-13 (Centralia Plant's 2022 U2 Boiler Tune-up Report).

Skeleton crew staffing has and will further exacerbate the plant's proper functioning. For example, TransAlta's local air regulator, which conducts regular inspections, issued it two Notices of Violation in December 2025 for issues that may have been related to reduced staffing and/or maintenance. Ex. 11 at ¶ 12. The first was related to excess emissions from the fly ash unloading baghouse and the second was for not fully engaging all relevant pollution

control equipment prior to firing coal on startups. Exs. 11-14, 11-15 (SWCAA Notices of Violation No. 10642 and No. 10643).

TransAlta Centralia's coal-fired power also costs more, so ratepayers are likely to pay higher electricity bills to the extent there are continued coal-fired operations. Centralia power is priced significantly higher than the wholesale energy market price: $62.04 per MWh for Centralia versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15.

And DOE's order disrupts plans to strengthen reliability by converting Centralia to natural gas As discussed above, TransAlta has announced plans and submitted permit applications to convert its plant from coal to natural gas in order to operate as a peaking plant under a commercial agreement with Puget Sound Energy. This conversion is in danger of being disrupted and delayed by DOE's order to continue operating Centralia as a coal plant. The risk of delay will compound over time if DOE continues to extend its Order repeatedly, as it has done for other plants such as the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania.[9] DOE's interference thus harms the ability of utilities to take steps they see as necessary to improve reliability—TransAlta Centralia as a natural gas peaker plant will provide grid services that an outdated coal plant cannot. Ex. 49 at ¶¶ 5–7 (Declaration of David Gomez).

[9] *See* Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025).

2. Running Centralia results in health and environmental impacts

Continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonian's health (imposing direct harms on the State and its agencies), and impair visibility at Washington's iconic natural areas such as the Mount Rainer National Park. *See supra* pp. 13–18; *see also* Ex. 10. Centralia has been a significant source of air pollution in Washington including for particulate matter, sulfur dioxide, nitrogen oxides, dioxin and furans, mercury, heavy metals, and polycyclic aromatic hydrocarbons. Ex. 10 at ¶ 7; Ex. 52 at ¶ 8.

Those emissions are known to adversely impact human health. For example, dioxins and furans are highly toxic persistent environmental pollutants that can cause cancer, reproductive and developmental problems, damage to the immune system, and hormone disruption. Ex. 52 at ¶ 11. Mercury exposure poses especially significant health risks for pregnant women and infants because of its impacts on fetal development and infant health. *Id*.; Ex. 10 at ¶ 14. Polycyclic aromatic hydrocarbons (PAHs) cause a range of serious health risks including various cancers, respiratory and cardiovascular diseases, and reproductive health problems. Ex. 52 at ¶ 11.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above cleanup levels. *Id.* at ¶ 7. Continued aerial emissions of hazardous substances associated with TransAlta's coal operations have the potential to settle on and contaminate thousands of properties and create thousands of PLPs. *Id.* at ¶ 14. And the Centralia Coal Plant uses settling

ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15.

Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the continued operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million annually in Washington. Ex. 10 at ¶ 10. Moreover, even after the plant is converted to natural gas and begins operating again in 2028, the cleaner performance of the natural gas plant compared to coal-fired operations is expected to prevent an estimated 4–7 premature deaths, 2 nonfatal heart attacks, 24 cases of asthma onset, with an economic value of $68-110 million annually in Washington. Ex. 10 at ¶ 12. Children are acutely prone to these health risks because their bodies are still developing, and they have more exposure to airborne contaminants that settle on lawns, parks, and schoolyards. Ex. 52 at ¶ 10.

These health impact estimates are based on the assumption that Centralia continues to abide by the requirements of its environmental permits. Ex. 10 at ¶ 7. However, Centralia's most recent quarterly report and recent inspections of the facility indicate that maintenance on Centralia's pollution control equipment is due or overdue. Ex. 11 at ¶¶ 10-11. A local clean air agency also issued Centralia two notices of violation for exceeding emissions limits in December 2025. *Id*. at ¶ 12; Ex. 11-14 and Ex. 11-15. Therefore, emissions under emergency coal-fired operations may be even higher if TransAlta Centralia cannot operate at a lower load or make necessary repairs. *Id*. at ¶ 11.

In addition to these health impacts, TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural

areas, including at Mount Rainer National Park, located only 50 miles from the plant. And, because Centralia is the largest source of greenhouse gas emissions in Washington, Ex. 12, the continued coal-fired operations will also make it harder for Washington to achieve its statutory greenhouse gas emissions reduction requirements. *See* RCW 70A.45.020.

V. MOTION FOR CLARIFICATION

As set out in detail in Washington's Request for Rehearing below, because the Order exceeds DOE's authority, is unnecessary, and is harmful both to the grid and consumers it seeks to protect, Washington requests that DOE withdraw the Order in its entirety. If DOE retains the Order, however, Washington alternatively requests that DOE clarify that the Order directs readiness only and that TransAlta Centralia not operate in any capacity unless and until there is an actual energy shortage where existing resources operated by Wester Resource Adequacy Program participants, or imports from other regions, cannot meet demand.

The Order inconsistently states that Centralia Unit 2 "shall not be considered a capacity resource," but also purports to order Centralia's "continued operation." Ex. 1 at 2-4. The Order also purports to require Centralia to comply with environmental requirements "to the maximum extent feasible while operating consistent with the emergency conditions." *Id*. at 4. The Order is based in large part, if not entirely, on a rare and hypothetical scenario set out in the NERC Winter Reliability Assessment report: a region-wide "extreme" weather event that knocks thermal generating sources off the grid for a period of time.[10] Ex. 2 at 37

[10] As discussed in Section VI.D.-E., the very fact that DOE's purported "emergency" is based on rare and potential *future* events that Balancing Authorities are actively mitigating against makes clear just how far outside the bounds of section 202(c) DOE is operating.

(NERC 2025-2026 Winter Reliability Assessment). Allegedly to counter this hypothetical occurrence, and among other measures, the Order at p. 4 states: "[b]ecause this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a *capacity resource*." (emphasis added). This language first appeared in Order No. 202-25-4, directed at PJM and the Eddystone Facility in Pennsylvania. Ex. 28. The language was omitted from DOE's earlier Order No. 202-25-3, directed at MISO and the J.H. Campbell Facility in Michigan. Ex. 27. But the language was inserted when DOE renewed the Campbell Order via Order No. 202-25-9. Ex. 36. The language also appears in two additional orders again directed at MISO: Order No. 202-25-12 related to the R.M. Schahfer Facility and Order No. 202-25-13 related to the F.B. Culley Facility, both in Indiana. Ex. 37 (U.S. Dep't of Energy, Order No. 202-25-12, Dec. 23, 2025) (Schahfer Order); Ex. 38 (U.S. Dep't of Energy, Order No. 202-25-13, Dec. 23, 2025) (Culley Order).

But "capacity resource" does not appear to have any discernable meaning relevant to either Washington or the WECC. This is likely due to the fact that, as with the Second Campbell, plus the Schahfer and Culley Orders, DOE apparently copied this requirement verbatim from the Eddystone Order. And the reference *does* have a context and meaning as related to Eddystone. Specifically, the PJM Capacity Market Manual expressly defines "capacity resource" in terms unique to PJM: i.e., it refers to identified megawatts of capacity pursuant to the PJM Reliability Assurance Agreement. *See* Ex. 39 at 236 (PJM Manual). As the public interest organizations pointed out in section IV.A of their request for rehearing, Eddystone units were not selected in PJM's capacity market because other resources were

available and less expensive to run. Ex. 40 at 14-17 (Eddystone Request for Rehearing). DOE ordered Eddystone to run anyway despite economic dispatch obligations, and, to do so, DOE needed to specify that the Eddystone Units would not participate in the capacity market.

It is not clear what DOE means by "capacity resource," as TransAlta Centralia is a merchant plant, not a resource operated at the direction of an ISO or RSO. Presumably, DOE means the balancing authority and/or reliability coordinator may call upon Centralia's operation only in the case of an actual energy shortage and where existing resources operated by Western Resource Adequacy Program participants cannot meet demand. This would also satisfy the issue raised in footnote 11 of the Order, referencing concerns about starting and stopping the facility leading to a potential breakdown. Ex. 1 at 2, fn. 11. Those concerns are mollified to the extent that Centralia simply prepares to operate, but is not called upon to actually run, unless and until there is an emergency loss of regional capacity that cannot be addressed by other resources, including power imports. As discussed in Section VI below, this is in fact the only logical way to read the Order given that mandating continuous operation of Centralia will have destabilizing impacts to the grid, unnecessarily violate applicable environmental limitations in conflict with the Federal Power Act, and ultimately cause negative impacts on ratepayers.

Because the Order is unclear on when Centralia may operate, Washington requests that DOE, if it does not rescind the Order in its entirety, clarify that Centralia may run only when necessary to meet an actual energy shortage and no other resources or imports are able to meet demand.

VI. REQUEST FOR REHEARING

A. DOE's Order Is Unlawful Because It Fails to Establish the Predicate Existence of an Emergency as Defined by Section 202(c) of the Federal Power Act or DOE's Own Section 202(c) Regulations

1. Because section 202(c) authority is extraordinary, Congress carefully cabined its use to wartime and *actual* "emergencies"

Enacted in 1935, section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), confers on the federal government an extraordinary authority in times of crisis. During times of war or similar "sudden" emergency circumstances, section 202(c) grants DOE power over in-state energy production and to command that market participants take actions necessary to address the emergency.[11] 16 U.S.C. § 824a(c)(1). Specifically, section 202(c) provides, in pertinent part:

> During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . the Commission shall have authority . . . with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, deliver, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.

Id. This is an exception to the Federal Power Act's policy of retaining to states those decisions related to energy resources. *See* 16 U.S.C. 824(b)(1). But Congress bounded this authority in critical ways. Section 202(c) empowers action *only* in cases of war or during an "emergency"; i.e., circumstances that are both imminent and unforeseen.

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[11] Section 202(c)'s reference to the "Commission" now refers to DOE under the Department of Energy Organization Act. *See* 42 U.S.C. § 7151(b).

First, as Michigan and others have pointed out to DOE in relation to recent orders, while the statute does not define what constitutes an "emergency," the word has a very specific and narrow meaning, both now and at the time section 202(c) was enacted. In 1935, an "emergency" meant "a sudden or unexpected appearance or occurrence . . . [a]n unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Webster's New International Dictionary of the English Language (1930). That understanding has not changed in the intervening years. *See* Webster's Dictionary 407 (9th ed. 2009) (defining "emergency" as "an unforeseen combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency"); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n. 147 (2025) (the definition of "emergency" has been static for "many years").

Section 202(c) also requires imminence. As expected of authority springing to life only in emergency circumstances, the plain text speaks of situations arising in the *present* tense, not hypothetical circumstances that might arise in the future. Section 202(c) references "*[d]uring* the continuance of any war" and "whenever … an emergency *exists*.") 16 U.S.C. § 824a(c)(1) (emphasis added). This is reinforced by Congress limiting DOE to those actions that "best meet the emergency" and limiting the temporal reach of section 202(c) orders to a maximum of 90 days unless an additional period of time is necessary to "meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1), (3).

Likewise, where section 202(c) orders conflict with federal, state, or local environmental laws, Congress requires DOE to limit its order to "only during hours necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(2). But here, the Order's

claimed emergency authority rests on a speculative series of future events—not any actual or imminent emergency. The Order contemplates that there may be (1) a peak period of demand for power; *and* (2) extreme weather causing the outage of thermal power plants; *and* (3) adverse wind turbine conditions; *and* (4) extreme weather extending to neighboring regions, preventing the Northwest Region from importing power. *See* Ex. 1 at 1, 3 (speculating that increased energy demand "*could* lead to the potential loss of power") (emphasis added).

Section 202(c) authority also does not extend to the *future* resource adequacy concerns the Order purports to address, as the Federal Power Act reserves jurisdiction over electricity generation and resource adequacy planning to the States. *See* 16 U.S.C. § 824; *see also Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016). Notably, Congress granted other authority, under section 202(b), to order the sale of electricity when necessary to avoid future emergencies, but only upon application to the Commission and after a full hearing—none of which has occurred here. *See* 16 U.S.C. 824a(b); *Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 234 (8th Cir. 1970) (explaining that, unlike section 202(c), section 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission).

Taken together, the statutory text makes clear that section 202(c) limits DOE's emergency authority to just that: events that are imminent, certain to occur, and unexpected. *Otter Tail Power*, 429 F.3d at 234. It does not grant authority to look years into the future to regulate long-term resource adequacy.

2. DOE's own section 202(c) regulations and prior actions make clear that a 202(c) order is limited to true emergencies

DOE's section 202(c) regulations make clear that DOE has also long understood its section 202(c) authority to be limited to imminent, certain, and unexpected power shortages, not generalized and long-term concerns about resource adequacy. Those regulations narrowly define "emergency" as an "unexpected inadequate supply" of electricity caused by "the unexpected outage or breakdown of facilities for the generation, transmission or distribution of power" that may be caused by unforeseen events such as "weather conditions, acts of God, or *unforeseen* occurrences not reasonably within the power of the affected 'entity' to prevent." 10 C.F.R. § 205.371 (emphasis added). Even then, actions taken pursuant to section 202(c) are only those "envisioned as meeting a *specific* inadequate power supply situation." *Id*. (emphasis added). DOE itself provides gloss on just how specific, suggesting that an emergency exists only when projected energy deficiencies "without emergency action by [DOE] will equal or exceed 10 percent of the applicant's then normal daily net energy for load." 10 C.F.R. § 205.375. And while true that DOE's regulations indicate that an emergency can spring from "inadequate planning or the failure to construct necessary facilities," the fact that an emergency power shortfall *can* result from inadequate planning does not change the fact that the shortfall itself must be imminent. *See* 10 C.F.R. § 205.371.

This is a narrow lane, designed to allow DOE to step in only where conditions that could not be anticipated beforehand result in an existing or imminent loss of power, not where—as is the case here—the Administration simply disagrees with the market forces driving state and private actors' shift away from coal to other sources of electricity like natural gas. *See id*. Indeed, in the preamble to DOE's section 202(c) rules, DOE expressly disavowed

any intent to "replace prudent utility planning and system expansion" or supplant state and regional regulators' obligations to "solve long-term problems." Energy, *Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Power*, 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981).

History bears this out. As discussed above, until DOE's recent orders, section 202(c) authority has been sparingly deployed to address actual emergencies. Since assuming section 202(c) authority, DOE's pre-2025 use of section 202(c) involved circumstances like hurricanes, extreme heat and cold events, lightning strikes, and the Enron energy crisis. Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 839 (2025). While some of these events necessitated a longer timeframe, most lasted only a period of *days*, not the rolling 90-day orders DOE now deploys to end-run planned retirements or conversions of coal facilities.[12] *See id*. And in each invocation of section 202(c) prior to 2025, the emergency order was predicated on a request by the related system operator or utility, not unilateral action. *Id*. DOE's use of 202(c) to meddle with long-range planning Congress expressly left to the states flies in the face of DOE's regulations, which delineate a restrained view of section 202(c) authority.

[12] DOE has re-upped its section 202(c) orders related to coal facilities in Michigan and Pennsylvania, despite the fact that the NERC winter reliability report no longer identifies the region as under any elevated risk for power shortages during extreme weather events. Ex. 2 at 26. Washington anticipates DOE will not deviate from this pattern here, and intends to force TransAlta to remain operating as a coal facility indefinitely as part of the Administration's ongoing efforts to end the alleged "war" on coal.

3. DOE lacks discretion to bypass congressionally-imposed limits on section 202(c) authority

It should be beyond dispute that, in exercising "emergency" authority under section 202(c), DOE is bound by the definition of the word "emergency." *Contra* Ex. 34 at 7; (Campbell Rehearing Order, Sept. 8, 2025). DOE's prior assertion, *see id*., that the Secretary is not bound by the actual definition of the word "emergency" is simply incorrect. *See* Ex. 34 at 7 (Campbell Rehearing Order, Sept. 8, 2025).

Section 202(c) is subject to judicial review, indicating that Congress clearly understood the potential risk of section 202(c) authority being stretched beyond the bounds of what it intended and demonstrating that DOE is accountable to the courts for adhering to the law. 16 U.S.C. § 824a(c)(5); 16 U.S.C. § 825*l*. And, no less so than the courts, when the Secretary is construing a statutory term, the "task is to apply the law's terms as a reasonable reader would have understood them at the time Congress enacted them" because "only the words on the page constitute the law adopted by Congress and approved by the President." *Students for Fair Admissions, Inc. v. President and Fellows of Harvard College*, 600 U.S. 181 (2023) (Gorsuch J., concurring) (citation modified); *citing Bostock v. Clayton Cnty., Georgia*, 590 U.S. 644, 654 (2020). This is critical because if the Secretary could "remodel, update, or detract from old statutory terms inspired only by [his] own imagination[]," he risks "amending statutes outside of the legislative process reserved for the people's representatives." *Bostock*, 590 U.S. at 654–55. DOE's prior statements in another coal "emergency" order demonstrate that this risk is effectuated by DOE's current approach to section 202(c). Ex. 34 at 7 (asserting that the plain meaning definition of the key term in the statute is immaterial to the

determination of a section 202(c) "emergency"). That alone is basis for DOE to withdraw its recent spate of section 202(c) orders—including this one—as unlawful.

In short, while the Secretary has some discretion to determine when an emergency exists, he does not have the discretion to ignore the plain meaning of the word "emergency" in doing so—especially when that construction flies in the face of the Federal Power Act's narrow grant of federal authority. Under the clear statutory text, an emergency under section 202(c) is just that: a temporary, unforeseen, and extraordinary circumstance that requires an extraordinary response. *See, e.g., Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); *Otter Tail Power,* 429 F.2d at 234. Congress did not intend this authority to cover circumstances like this one: remote and wholly speculative *future* weather phenomena and long-range energy planning goals over which the Federal Power Act expressly denies to DOE. *See La. Pub. Serv. Comm'n v. F.C.C.*, 476 U.S. 355, 357 (1986) ("[A]n agency literally has no power to act . . . unless and until Congress confers power upon it.").

B. DOE's Order Violates Section 202(c) Which Does Not Allow DOE to Usurp Local Authority to Address Both Short- and Long-Term Resource Planning

DOE's Order also violates clear Federal Power Act prohibitions against the federal government dictating long-range power planning to the States, because that is precisely what the Order attempts.

Despite the narrow scope of section 202(c), it is clear from both this Order, the President's Executive Order on Grid Reliability and DOE's response to it,[13] including its methodology report published in July 2025 and other section 202(c) orders issued this year, that DOE is using its section 202(c) authority for circumstances beyond actual emergencies and instead seeks to override local planning authorities when it comes to generalized short- and long-term concerns regarding resource adequacy. For instance, the Order itself speaks of "energy challenges *facing the Nation* due to growing resource adequacy concerns." Ex. 1 at 2 (emphasis added). Citing DOE's July 2025 Resource Adequacy Report, the Order further references addressing problems with "*the Nation's* power grid … to meet projected demand for manufacturing, re-industrialization, and data centers." *Id*. at 3-4 (emphasis added). And DOE's press release touting the Order focuses almost entirely on long-range concerns, including broad claims regarding "blackouts *in the coming years*" and "blackouts … potentially increas[ing] 100 times *by 2030* if the U.S. continued to take reliable power offline as it did during the Biden administration." Ex. 42 (Dec. 17th press release) (emphasis added). The Winter Reliability Assessment appears in the press release merely as window dressing. *See id*.

Indeed, DOE has directly claimed to have such sweeping authority. In addressing arguments raised by rehearing requests related to the Campbell Order, DOE expressed the view that its section 202(c) authority is essentially unbounded. Ex. 34 at 6-7. At base, DOE

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[13] *See* Ex. 33 at 35-36 (explaining that, pursuant to the President's Executive Order on Grid Reliability, DOE developed a new methodology and protocol to guide its emergency section 202(c) orders across the country).

claims that, despite what the statute or its own regulations provide, an "emergency" is whatever the Secretary decides it is, including generalized and nationwide supply concerns. *Id*. And, while DOE's rehearing order claimed an "imminent" need to maintain the Campbell plant because of the NERC assessment and the fact that "retired generation facilities generally cannot be brought back online in a matter of days," *id.* at 7, that explanation has now been wholly belied by the fact that DOE extended both the Campbell and Eddystone Orders for additional 90-day terms despite the fact that neither region is identified as "at risk" for energy shortages this winter. Ex. 2 at 6.

In so doing, DOE says the quiet part out loud. As discussed in more detail in Section VI.D.5 below, DOE's coal-facility orders are now—and always have been—about one thing: claiming unfettered authority to use section 202(c) to override state and local plans to close or transition old and unreliable coal power plants in furtherance of the Administration's goal of "ENDING THE WAR ON BEAUTIFUL, CLEAN COAL" (emphasis original).[14] *See* Ex. 43 (*Promises Made, Promises Kept*, Department of Energy, Dec. 18, 2025). Indeed, and as if to underscore this already naked policy goal, just 48 hours after issuing the Centralia Order, DOE touted: "[t]hanks to President Trump, wages for coal workers are up and coal plants across the country *are reversing plans to shut down*." *Id*. (emphasis added). Issuing emergency orders based on a preference for coal-fired power over other sources of energy violates the Federal Power Act's prohibition on undue discrimination or preference in rates. *See* Ex. 35 at 27-29.

[14] That list includes Campbell, TransAlta Centralia, and now F.B. Culley and R.M. Schahfer.

DOE's assertion that general, nationwide concerns over power needs in the future are an "emergency" under section 202(c) are also meritless. For one, DOE's Order runs headlong into the Federal Power Act's carefully constructed balance between state and federal authority, reserving to states the ability to address long-term energy planning. These limitations permeate the Federal Power Act. *See, e.g.*, 16 U.S.C. §§ 824(a), (b)(1); 16 U.S.C. § 824o(1)-(2); 16 U.S.C. § 824a(c); 16 U.S.C. § 825*l*. But 2005 amendments to the Act powerfully reinforced them based, in part, on concerns that the Act as written did not allow the federal government to take steps ensuring bulk-system reliability. To remedy, Congress added section 215 to the Act, allowing the federal government to enforce those mechanisms. *See Rules Concerning Certification of the Elec. Reliab. Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliab. Standards*, 70 Fed. Reg. 53,117, 53,118 (Sept. 7, 2005).

But Congress did so surgically and in line with existing limits on federal authority by making clear section 215 did not include the ability to order "the construction of additional generation" and explicitly refusing to preempt "*any* authority of *any* State to take action to ensure the safety, adequacy, and reliability of electric service within that State." 16 U.S.C. § 824o(i)(1)-(2) (emphasis added). Yet preempting state authority is precisely what DOE does here with its expansive read of section 202(c) as granting it authority to dictate which Washington specific resources DOE believes are necessary to satisfy long-term energy demands.

Moreover, DOE's Order does not address—much less provide any basis to override—existing state resource adequacy planning. As discussed below, Washington, like appropriate

state and regional authorities around the country, is already planning for and working to address long-range adequacy and reliability concerns. An important piece of that planning includes expanding TransAlta Centralia's capacity, ironically the very thing DOE's Order interferes with. Again, this interference comes despite the fact that the Federal Power Act provides DOE *no* authority "over facilities used for the generation of electric energy" except where expressly authorized. In so doing, Congress commanded that "Federal regulation … extend[s] only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). DOE's position that section 202(c) emergency authority is such an express authorization because it extends to general resource adequacy concerns makes a mockery of the Act. If, as DOE claims, its authority to declare an emergency is unfettered and reaches to generalized short- and long-term resource adequacy planning, the Federal Power Act's limitation on DOE's emergency authority is effectively meaningless. When everything is an emergency, nothing is.

To wit, and to the extent it could ever *per se* justify a section 202(c) order, even NERC assessments apparently no longer matter. *See* Ex. 36; Ex. 63; Ex. 38; Ex. 37; and Ex. 94 (U.S. Dep't of Energy, Order No. 202-25-14, Dec. 30, 2025) (Craig Station Order). Nor do "sudden," "unexpected," or "unforeseen" power shortages. *See* 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. As a result, it is difficult to view DOE's justification for these orders as anything other than a blanket determination that an ongoing, *nationwide* emergency exists and will continue through the rest of this administration. DOE, thus, turns significant limitations on what is essentially a wartime power into ongoing and unfettered authority to run roughshod over the power sector—but with none of the usual safeguards in place to ensure that American

consumers are protected.[15] This absurd and unlawful construction of the statutory text does not survive even the mildest scrutiny. *Armstrong Paint & Varnish Works v. Nu-Enamel Corp.*, 305 U.S. 315 (1938) ("to construe statutes so as to avoid results glaringly absurd, has long been a judicial function"). And extra scrutiny is required here because DOE is claiming to "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. EPA*, 597 U.S. 697, 724-25 (2022) (cleaned up).

Finally, assuming *arguendo* DOE could redefine "emergency" and adopt a new practice of using section 202(c) to prevent the retirement of power plants based on long-term energy needs, hypothetical scenarios, or DOE's new methodology for assessing grid reliability, DOE's Order is still unlawful because DOE never provided the public notice or an opportunity to comment on its new procedures. *See* 5 U.S.C. § 553. DOE has markedly changed its section 202(c) practice in response to President Trump's executive order on grid reliability. *See supra* § IV.C-E. That executive order directed DOE to establish a new methodology and "protocol" to use section 202(c) to prevent retirement of power plants in "at-risk region[s]" the methodology identifies. *See* 90 Fed. Reg. 15521; *see also* Ex. 35 at 12-13, 14-15, 34-36 (describing DOE's position that its methodology will guide future section 202(c) interventions). DOE now issues section 202(c) orders based on its new

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[15] While the Order fails legal muster even as a stand-alone directive, it is especially egregious in light of a nationwide abuse of section 202(c) authority. As discussed in Section VI.E. below, these orders are decidedly *anti*-consumer. This is particularly illustrated by the Campbell order that, by some estimates, will ultimately cost impacted ratepayers over $100,000,000 and counting. *See, e.g.*, Ex 74 at 8 (Michael Goggin, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants*, August 2025).

methodology, projections of long-term needs, and generalized statements about energy trends, and with the intent to renew them on a prolonged, indefinite basis.

Such is the case here, DOE issued the Order pursuant to its methodology and the President's executive order, *see* Ex. 1 at 2-3, and makes a generalized finding of emergency across multiple states unmoored from any particular triggering emergency event. However, DOE has never publicized its protocol or responded to public comment on its methodology. However, as explained more fully in the States' earlier rehearing request, public comment is required under the APA because DOE's practice has concrete legal effects – this Order being one of them – and is inconsistent with DOE's existing regulations and past practice. *See* Ex. 35 at 34-38.

C. DOE's Order is Arbitrary and Lacks Substantial Evidence Supporting Its Determination That an Emergency Exists in the Northwest

Under the Federal Power Act, substantial evidence and reasoned decisionmaking must support DOE's orders. 16 U.S.C. § 825*l*(b); 5 U.S.C. § 706(2)(E); *see also Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (noting that Federal Power Act orders must also be either "consistent with past practice or adequately justified"); *see also, e.g., Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962). DOE's Order fails in this regard and should be withdrawn.

1. Generalized, unsupported statements in executive orders do not support DOE's finding of an emergency here

The Order cites Executive Order 14156 and 14262 as apparent bases for its determination that an emergency exists pursuant to section 202(c). This reliance is grossly misplaced.

For one, a generalized, unsupported statement that the nation faces a dire energy situation or is experiencing a surge in electric demand, is insufficient as a matter of law to justify a section 202(c) order. The Federal Power Act requires the DOE Secretary to independently determine that emergency action is required in a given circumstance based on evidence. *See* 16 U.S.C. § 824a(c)(1) (authorizing action "whenever the Commission determines" an emergency exists). Generalized, unsupported findings in executive orders, which broadly state the president's views on energy matters, cannot support an emergency order under section 202(c).

Further, as discussed above, the emergency under the Federal Power Act and DOE's regulations must involve a war or "sudden" and "unexpected" inadequate energy supply. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Neither executive order comes near this standard, much less the substantial evidence required by the Federal Power Act. For instance, EO 14156 makes only generalized claims and grievances about "policies of the prior administration" related to energy prices and capacities, as well as broad statements about future energy needs. Ex. 44 at 1 (Executive Order 14156). While it does make statements about "inadequate and intermittent energy supply, and an increasingly unreliable grid," the EO does not substantiate those claims. *Id*. at 1-2.

EO 14156 is also internally inconsistent in a way that completely belies any alleged energy emergency. It claims a massive need for increased energy production, yet it excludes nearly all sources of renewable energy. In fact, since January 2025, the Trump Administration has aggressively targeted critical energy projects around the nation for cancellation. One recent estimate stated that, culminating with the President's "One Big Beautiful Bill," "[f]ifty-two large-scale clean energy projects were cancelled, closed, or downsized in 2025—more than any other year since [the study's authors] began tracking." Ex. 45 at 1 (E2 Clean Economy Works: November 2025 Analysis). This represents a loss of "$32 billion in clean energy investments and 40,000 jobs." *Id*. In fact, the Secretary bragged in October of this year that DOE alone terminated $7.52 billion in financial awards for clean energy projects in 2025. Ex. 46 at 1 (*Energy Department Announces Termination of 223 Projects*, U.S. Dep't of Energy, Oct. 2, 2025). This comes despite the fact that DOE itself has acknowledged "[t]he rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth's natural heat, has the potential to vastly improve the reliability of the American energy system." Ex. 47 at 3 (*Energy Reliability and Resilience*, U.S. Dep't of Energy (Archive)).

In no way does EO 14156 justify the Order.

2. DOE misreads and misrepresents the sources it cites to conclude an emergency exists pursuant to section 202(c)

As noted, the Order cites two sources to support its allegation that "an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area." Ex. 1 at 1. The Order first cites to NERC's 2025-2026 Winter Reliability Assessment to support the assertion that WECC Northwest "is at elevated risk during periods of extreme

weather." *Id*. (citing Ex. 2 at 6). The Order next cites to a PowerPoint presentation from Energy + Environmental Economics (E3), Ex. 1 at 1, which states that a there will be a "resource gap" starting in 2026 which will grow until 2030 and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026." *Id*. (citing Ex. 3 at 10). As described below, DOE makes a fundamental error by equating these out-of-context statements with a conclusion that there is an emergency in the Northwest over the next three months because the cited studies do not support the conclusion that there is an emergency, or even that an emergency is likely to occur soon.

a. The 2025-2026 Winter Resource Reliability Assessment

The Order's citation to the NERC 2025-2026 Winter Reliability Assessment does not support the conclusion that there is an emergency.

While the Winter Reliability Assessment states that WECC Northwest "is at elevated risk during periods of extreme weather," the analysis also predicts zero hours and zero energy going unserved this winter. Ex. 51 ¶ 14 (Declaration of Joel Nightingale) (citing Ex. 2 at 15, Table 5). The explanation for this is simple: the NERC criteria for "elevated risk," which is a step below the "high" risk category, is a far cry from forecasting an imminent emergency.[16] On page 15, the Winter Resource Assessment concludes that "the results of the probabilistic

[16] *See* Ex. 2 at 11 (Outlining the criteria for "elevated risk" as: "Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with normal resource scenarios (i.e., typical or expected outage and derate scenarios for conditions); or Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with reduced resources (i.e., extreme outage and derate scenarios)") (citations omitted).

assessment reveal *no* [Expected Unserved Energy] or [Loss of Load Hours] for Winter 2025–2026." Ex. 2 at 15, Table 5 (emphasis added).

Moreover, the Order cites the Winter Reliability Assessment's estimate of a 9.3% increase in winter peak demand as justification for delaying the retirement of Centralia. Ex. 1 at 1. But it fails to mention that the Winter Reliability Assessment also estimates a 12.2% *increase* in prospective winter peaking resources. Ex. 2 at 49. This increase in resources more than offsets the cited increase in winter peak demand. Ex. 51 ¶ 16; Ex. 53 ¶ 11. To be clear: the Winter Reliability Assessment predicts a 3.3% increase in the Northwest's reserve margin compared to the previous year, even presuming retirements, including Centralia. Ex. 51 ¶ 16; Ex. 2 at 37, 49. There is no emergency.

b. The E3 PowerPoint presentation

DOE similarly misconstrues the E3 resource adequacy PowerPoint. This presentation, and the forthcoming report it summarizes, was commissioned by an array of Pacific Northwest electric utilities, essentially representing the entirety of power supply in the WECC Northwest. Ex. 3 at 2. E3's goal is to evaluate the state of resource adequacy in the Pacific Northwest and present specific recommendations to the region as to how to address those needs in the coming years. *Id*.

E3's engagement on this effort is direct confirmation that the process actually envisioned by the Federal Power Act is fully functioning here—i.e., states, regional planning authorities, and local utilities assessing power needs and executing on long-range planning goals. *See, generally,* Ex. 3. But, like the Winter Reliability Assessment, this document does not support the assertion that there is any emergency. Ex. 53 ¶ 12. Resource adequacy

evaluations such as these are focused on assessing the ability to provide electricity in worst case scenarios, but do not necessarily purport to predict whether those scenarios will occur. Ex. 3 at 11-13, 19. And, critically, the E3 report specifically indicates that any general "shortfall" in 2026 can be addressed through imports, a fact that the Order completely ignores. Ex. 3 at 10 (stating clearly that the rather small shortfall of 1,321 MW out of a total need of 50,737 MW, i.e., 2.6 percent, can be met through imports); *see also* Ex. 99 (Sylvan Energy Analytics, *Near-term winter resource adequacy challenges in the Pacific Northwest*, January 2026).

Putting this aside, the shortcomings in DOE's reliance on a PowerPoint presentation of a yet-to-be-released *draft* report are now readily apparent. For one, the deficit margin for 2026 is now estimated to only be a fraction of that already small deficit set out in the presentation once in-development resources coming online in 2026 are included.. E3 indicates the loss of load expectation for 2026 is 0.15 days per year. Ex. 91 ¶ 4 (Declaration of Arne Olson); *see also* Ex. 41 at ¶ 6.

Second, the Order also ignores E3's observation that resource adequacy *events* (i.e., actual emergencies or near-emergencies) usually take place in the northwest when there are "[e]nergy shortfalls that occur during low hydro years" Ex. 3 at 11-13, 19. The report does not make any prediction that 2026 will be a low hydro year. In fact, according to the EIA's short-term energy outlook published on December 9, 2025, all indications point to winter 2025-2026 having *better* hydro conditions than winter 2024-2025. Ex. 51 at 5, Table 1 (*citing* the U.S. Energy Information Administration's (EIA) Short-Term Energy Outlook published on December 9, 2025). *See* Ex. 61 (EIA Short-Term Energy Outlook). When combined with

the EIA's short-term outlook, E3's analysis set out in the PowerPoint supports the conclusion that a resource adequacy event is unlikely this winter. *See* Exs. 51, 61.

The E3 analysis also serves to highlight the Order's negative impact on resource adequacy over the next five years. Specifically, the Order cites the E3 estimate of a nearly 9 GW shortfall in 2030 as a concern DOE seeks to address. Ex. 1 at 1. But, as discussed in detail in Section VI.E.2, the Order impacts and, if continued, will prevent TransAlta from beginning the planned transition of Centralia to natural gas that would help address that very shortfall—a fact that alone renders the Order arbitrary and capricious. Ex. 51 at ¶ 17. Indeed, the E3 PowerPoint was presented in September of 2025, before TransAlta publicly announced plans to convert the Centralia site into a natural gas facility. The conversion of Centralia would therefore have added to the planned conversions noted on slide 10 of the PowerPoint. E3's presentation also specifically highlights that "[n]atural gas is the only viable near-term firm capacity option, yet siting new gas plants is extremely challenging and may create stranded asset risks." Ex. 3 at 22. If DOE is concerned about the Northwest's resource adequacy over the next 5 years and trusts the analysis presented in E3's report, then it could not have picked a worse course of action. The Order effectively prevents or delays the addition of a natural gas facility in 2028 that would not have needed new siting and would add capacity.

3. DOE's July Resource Adequacy Report, even with significant flaws, directly contradicts the Order

DOE's July 2025 Resource Adequacy Report, Ex. 4, also fails to provide substantial evidence of an emergency here, regardless of how DOE chooses to define that "emergency."

As DOE is aware, on August 6, 2025, Washington and several other states filed a Motion to Intervene and Protective Request for Rehearing regarding the 2025 Resource

Adequacy Report. Ex. 35. In that request, the States noted, "[g]iven that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time." *Id*. at 1 (*citing* 16 U.S.C. § 825*l*). The States further "reserve[d] all rights to present these objections, or any other objection or legal challenge to the Report or DOE's reliance on this report going forward." *Id*. DOE responded to the Resource Adequacy Report Rehearing by stating that the Report was not an order under the Federal Power Act and, therefore, not subject to rehearing. Ex. 48 (*Dep't of Energy Response to State Rehearing Request of Aug 6*, Sept. 5, 2025). DOE never modified its report or responded to critiques the States and others raised about the report.

Because DOE relies on the Resource Adequacy Report as a basis for the TransAlta Centralia Order, Washington fully incorporates by reference the Resource Adequacy Report Rehearing request herein. For the reasons set out in our prior filing, and summarized below, the flaws in the Resource Adequacy Report undercut DOE's attempt to rely on it to further justify the TransAlta Centralia Order, and DOE's reliance on the Report provides yet an additional reason why the Order should be withdrawn.

As set out in the Resource Adequacy Report Rehearing, the Report suffers from a host of infirmities. The Report contains numerous analytical, mathematical, and empirical flaws. Its assumptions about load, growth, retirements, and capacity additions are unreasonable and unsupported by evidence or logic. *See* Ex. 35 at 21-25. Far from the only example, DOE unreasonably presumes that the market, grid operators, and state regulations will allow unrestrained load growth through 2030 regardless of its impact on reliability. *See id*. 22-23. The Resource Adequacy Report further: (1) acknowledged that data and input from other

states and regional entities could improve the analysis, but failed to consult with those entities or seek to obtain that data; (2) selected non-traditional and non-standardized resource adequacy metrics; and (3) arbitrarily relied on geographic groupings that fail to match the actual boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC Reliability Coordinators to reliably operate the Nation's electric grid. *See id*. 25-27.

Moreover, the Report rests on a transparently arbitrary definition of "firm capacity" that includes only fossil-fuel power plants. *See id*. 17, 21. This and other analytical flaws indicate that DOE seems to have prejudged the Report's outcome in order to pursue an extra-statutory motive, namely preserving aging and uneconomic fossil fuel power plants at consumer expense in direct contravention of the Federal Power Act's express goal of preserving just and reasonable rates and preventing undue discrimination or preference. *See id*. 27-29.

The Report also fails to consider reasonable alternatives. Specifically, the Report ignores, with no explanation, alternatives like: expanding interregional transmission, installing batteries and other energy storage technologies, deploying renewable energy, and requiring data centers to meet flexibility standards. *See id*. 20 – 25. Most glaringly, the Report ignores the existing resource adequacy mechanisms that are used by state and regional grid operators to assess reliability and respond to resource adequacy needs. *See id*. 4-10, 31-32. That is a convenient omission as the Report is now being used to justify 202(c) orders that intrude on matters reserved for the States. *See* 16 U.S.C. § 824(b)(1); *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001).

Yet, even under DOE's biased projections, the July Assessment fully contradicts any finding of an emergency, reinforcing the arbitrary nature of the Order. The Resource Adequacy Report concluded that the WECC Northwest meets reliability standards. Ex. 4 at 7. Per DOE, any potential reliability issues would occur years in the future, and only if DOE's speculative assumptions about future supply and demand prove accurate. Forcing ratepayers to pay to keep generation online that is not needed, simply because technology companies *may* be building more data centers in the future that *may* need that power is arbitrary and violates the Federal Power Act's requirement that rates be just and reasonable, especially as other analyses indicate that data center projections may be overblown. Ex. 96 (*PJM to Ratchet Down Projected AI Power Demand For Eastern US*, EnergyWire, January 6, 2026); *see also* Ex. 35-3 at 23, (Rehearing Ex. C Institute for Policy Integrity Report); Ex. 35-5 (Rehearing Ex. E London Economics International Report). And assuming *arguendo* that DOE could base an emergency finding on speculative conditions to occur years in the future, DOE's own analysis found that, if power plants retire as planned, there is still no reliability issue in the Washington subregion. Ex. 4 at 8. In fact, even not looking solely at the Washington sub-region, the West Non-CAISO region identified in the Report fares better than any other region in the country assessed, save CAISO. *See* Ex. 4 at 37.

The July Resource Adequacy Report fails to establish substantial evidence of an "emergency" and justifies DOE's withdrawal of the Order.

4. WECC Northwest has sufficient existing capacity resources to cover the winter months without Centralia

As noted, the retirement of coal generation at TransAlta Centralia has been in the works for well over a decade. It is no surprise, therefore, that regional utilities conducted their

planning for the upcoming peak winter months with that shut down in mind. As described below, both state and federal reporting demonstrates that WECC Northwest has adequate generation to maintain capacity during the upcoming winter peak season without Centralia. Any long-term uncertainty about capacity will be exacerbated, not aided, by DOE's current emergency order stalling the shutdown of coal generation at Centralia and potentially delaying conversion to natural gas.

First, both NERC and WECC "indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions." Ex. 22. While extreme weather poses an "elevated risk of short-duration outages absent additional measures" (such as backup generators or power imports) both BPA and Washington's utilities "do not forecast outages this winter." *Id*. This is partly because the "[m]ost constraining reliability conditions are extended wintertime cold weather events during very low water years" and, unsurprisingly, that "[l]oss of load events are concentrated during the lowest hydro years." Ex. 3 at 11-12. In other words, reliability depends on the "ability to supply energy during multi-day cold snaps under low hydro conditions." *Id.* at 19. But this year, the National Oceanic and Atmospheric Administration's 2025-2026 Winter Outlook predicts "above-average precipitation" in the Pacific Northwest, *see* Ex. 64 at 4 (NOAA, *Winter Outlook 2025-2026*, Nat'l Weather Serv.), and drought improvement is also expected in the region. *Id*. at 5. According to the Northwest River Forecast Center's 120-day hydrology forecast, which "is a leading indicator of near-term expected hydro generation," the region's rivers are at 114 percent of average. Ex. 49 at ¶ 8.

Next, other available studies show that capacity reliability for the upcoming winter season is sufficient for WECC Northwest. NERC's Winter Reliability Assessment gauged WECC Northwest's reliability in the coming months, spanning the 2025-2026 winter season. Ex. 2 at 4. Per NERC, "[o]perating reserve margins are expected to be met after imports in *all winter scenarios*." Ex. 2 at 37 (emphasis added). This is *after* taking into account the closure of Centralia. While acknowledging "[l]arge coal unit retirements and conventional hydro unit retirements" result in a ten percent reduction in capacity, the report states that "Tier 1 resources have soared over 580% . . . to over 3 GW." *Id*. NERC's assessment on WECC Northwest concludes with a statement that there is sufficient reliability in the region, asserting that the increase in firm imports (amounting to 6.1 GW) "absorbs" the reduction of 4 GW of "existing certain capacity."[17] *Id*. In simple terms, NERC's analysis "showed zero hours and zero energy going unserved this winter" in the Northwest region. Ex. 51 at ¶ 14.

Washington's investor-owned utilities have also concluded in their integrated resource plans that resource needs are met even when assuming the short-term loss of Centralia power. For example, Washington's largest utility, Puget Sound Energy, has filed seven integrated resource plans or resource plan progress reports since 2010, required filings for all Washington utilities that must include information about load forecast in the utility's service area and how that load will be met through distributed energy resources, supply-side resources, and renewable resources. WAC 480-100-620(2)-(5). None of Puget Sound

[17] This is in accord with DOE's own work. Washington disagrees that DOE's Resource Adequacy Report is a reliable source. *See* Section VI.C.3 *supra*. But, in that Report, DOE itself found "all regions except ERCOT have less than 2.4 hours of average loss of load per year[.]" *Id*. at 7.

Energy's integrated resource plans include TransAlta Centralia as a coal resource past December 31, 2025. Ex. 51 at ¶ 8. This indicates that, for well over a decade, Puget Sound Energy has been planning on meeting demands—including peak capacity needs—without Centralia. *Id*. Indeed, Puget Sound Energy recently confirmed to the Washington Utilities and Transportation Commission that its existing gas-fired generation is expected to fill the resource adequacy requirement gap left by TransAlta Centralia in the coming winter months. *Id*. at ¶ 11; Ex. 51-1 at 19:2–4.

Additionally, E3 discussed resource adequacy in its latest study presented to the Washington Utilities and Transportation Commission. *See* Ex. 3. The E3 study also excluded coal as a solution to the region's long-term resource adequacy concerns and instead focusses on three alternatives: (1) demand response, (2) battery storage, and (3) *natural gas*. Ex. 51 at ¶ 17. This last resource is critical. As E3 notes, "[n]atural gas is the only viable near-term firm capacity option." Ex. 3 at 22. This is because even the least agile natural gas plant is much more agile than a coal plant for start-up time and output time to meet load. Ex. 3 at 22; Ex. 51 at ¶ 20. Coal plants are also more likely to trip out of service than their gas counterparts. *Id*. at ¶ 21, Figure 1 Per NERC, the average weighted equivalent forced outage rate for coal is 11.7 percent as opposed to 7.7 percent for natural gas. *Id*. More than that, simple economics heavily favor operating this plant as a natural gas versus coal-fired unit. Ex. 49 at ¶¶ 5, 8.

Finally, these resources—and more—lead to one conclusion: extending Centralia's coal generating life is not a long-term solution for Pacific Northwest resource adequacy. A short-term extension of Centralia does not actually resolve capacity needs created by a "surge in electricity demand," Ex. 1 at 2, from sources like data centers and domestic manufacturing.

These are long-term increases in demand and will not go away after three months. Ex. 51 at ¶ 23. However, converting TransAlta to natural gas, with a planned capacity of 700 MW, supports that growth. Ex. 65 (*TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion*, TransAlta, December 31, 2025). Centralia cannot operate as a coal-fired plant while conversion takes place as construction is required to convert the facility from coal to gas fuel use. Ex. 51 at ¶ 24. To the extent that DOE is concerned about insufficient supply, postponing construction of a resource with operational capabilities better suited to meeting future load growth will be highly detrimental to mid-term resource adequacy in the region. *Id*.

In short, the available studies, and the fact the retirement of this facility as a coal-filed resource has been planned and expected for an extended timeframe, contradict the Order's assertion that the 2025-2026 winter season represents an "emergency" that warrants Centralia's continued operation as a coal plant. The Order does not contest the validity of state and utility planning identifying that adequate resources exist to cover the region's power needs for the foreseeable future, even without Centralia.

D. DOE's Order is Arbitrary and Capricious and Contrary to Law

Agency action is arbitrary or capricious where it is not "reasonable and reasonably explained." *Fed. Commc'ns Comm'n v. Prometheus Radio Project*, 592 U.S. 414, 423 (2021). An agency must provide "a satisfactory explanation for its action[,] including a rational connection between the facts found and the choice made." *State Farm*, 463 U.S. at 43 (internal quotation marks omitted). In doing so, the agency cannot rely on "factors which Congress has not intended it to consider[.]" *Id*. The "reasoned explanation requirement of administrative

law . . . is meant to ensure that agencies offer genuine justifications for important decisions, reasons that can be scrutinized by courts and the interested public." *Dep't of Commerce v. New York*, 588 U.S. 752, 785 (2019) (*Dep't of Commerce v. New York*).

In addition, when an agency "rescinds a prior policy," the agency must, at minimum, "consider the 'alternatives' that are within the ambit of the existing policy[,]" "assess whether there were reliance interests," and "weigh any such interests against competing policy concerns." *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30, 33 (2020). An action is also arbitrary and capricious if the agency "failed to consider . . . important aspects of the problem before" it. *Regents*, 591 U.S. 1 at 25 (citation omitted); *see also id.* at 30. An agency must "pay[] attention to the advantages *and* the disadvantages" of its decision. *Michigan v. E.P.A.*, 576 U.S. 743, 753 (2015).

DOE's Order fails all of these benchmarks.

1. The Order directs entities to act that have no authority to order TransAlta Centralia to run

DOE's Order is arbitrary and capricious because it is unclear who has authority to direct TransAlta Centralia's operation. Specifically, the Order states that TransAlta Centralia will be "available to operate at the direction of either the Bonneville Power Administration (BPA) (in its role as Balancing Authority) or the California Independent System Operator Corporation Reliability Coordinator West (in its role as the Reliability Coordinator)." Ex. 1 at 4. In support of this statement, footnote 18 of the Order cites to the NERC "list of acronyms for Reliability Coordinators" and the "NERC Compliance Registry." *Id*. n. 18.

But, in reality, it is entirely unclear whether BPA or CAISO actually serve in those roles. For one, Washington utilities have identified to counsel for the State that, in

conversations with BPA, BPA does not believe it has the authority to direct Centralia's operation. Other sources indicate that the Southwest Power Pool may operate as the Reliability Coordinator for TransAlta Centralia as part of its Western RC Services. Ex. 92 (Southwest Power Pool Map); Ex. 93 at 6 (GRID Compliance Audit), and that Gridforce Energy Management, LLC, is the Balancing Authority. *Id*. The Southwest Power Pool has separately identified to the State that they do serve as Reliability Coordinator for Gridforce relative to Centralia.

Either way, this renders DOE's Order arbitrary. Washington disagrees that there is even an emergency problem to be solved here. But, even if there were, DOE entirely fails to "consider an important aspect of the problem" by potentially naming the wrong entities who can even order Centralia to run—or at least failing to understand the complexities at play and the resulting confusion that would result. This renders the Order "so implausible that it [cannot] be ascribed" to any rational view or expertise. *Motor Vehicle Manufacturers Ass'n of the United States v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). This confusion illustrates the danger in DOE claiming "emergency" authority to exercise unfettered control over the Nation's power grids from now until some unspecified point in the future. In any event, this justifies immediate withdrawal of the Order.

2. The Order fails to comply with section 202(c)'s requirement to craft terms that "best meet the emergency and serve the public interest" and arbitrarily fails to consider reasonable alternatives

Washington disagrees that a legitimate section 202(c) emergency exists. But even if there was an emergency, section 202(c) mandates that DOE implement only those measures that "will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c)(1). This

requires energy to perform at least some analysis of available options and then select the option that is "most advantageous." *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (defining "best" in the context of the Clean Water Act's "best technology available" standard). The APA also requires DOE to consider reasonable alternatives as a hallmark of reasoned decision-making. *See Spirit Airlines, Inc. v. U.S. Dep't of Transp.*, 997 F.3d 1247, 1255 (D.C. Cir. 2021) (reviewing cases).

Thus, at a minimum, DOE must evaluate competing approaches and assess how effectively each would resolve the purported emergency and advance the public interest, accounting for the benefits and drawbacks of each option. *See, e.g., Michigan v. EPA*, 576 U.S. 743, 750-51(2015) (noting minimum requirements of "reasoned decisionmaking" by administrative agencies). While DOE need not analyze every conceivable option, it must examine approaches that fall within the regulatory framework, as well as options that are significant, feasible, or self-evident. *See Dep't of Homeland Security v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020). The scope of required alternatives analysis will vary with the nature of the crisis. A genuine emergency demanding action within hours would justify more limited analysis than a situation allowing days or months for deliberation. *See* 16 U.S.C. § 824a(c) (directing the exercise of judgment).

Here, DOE fails to exercise reasoned judgment on multiple levels. First, it does not appear that DOE engaged in *any* alternatives analysis, much less a reasoned one. The Order contains no explanation whatsoever for DOE's determination that ordering an aging coal plant with no workforce, no customers, and no coal is the option that "best meets" both the alleged emergency and the public interest. *See* Ex. 1. DOE's omission of an alternatives analysis

directly violates section 202(c)'s mandate to implement only those measures most effective in addressing the emergency.

The failure to address alternatives is particularly troubling when it comes to power imports because DOE's own regulations reinforce that a *lack* of available imports is one of the lynchpins that must undergird a section 202(c) order.[18] Specifically, DOE's rules identify categories of information applicants for a section 202(c) order must submit, and DOE must weigh when determining whether to issue, and how to craft, a section 202(c) order. 10 C.F.R. § 205.373. That required information encompasses "conservation or load reduction actions," "efforts … to obtain additional power through voluntary means," and that "*adequate electric service cannot be maintained without additional power transfers*." *Id*. (emphasis added). Yet the Order fails to address any of these issues, including the availability of imports to meet demand. *See* Ex. 1.

That failure is especially baffling here. The closest DOE comes to identifying any emergency need within the 90-day period of the Order is the hypothetical—and admittedly "extreme"—scenario identified in the NERC reliability assessment.[19] That very assessment

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[18] DOE's failure to evaluate *exports* is also troubling. In October 2025, DOE authorized entities within the NERC Northwest region—and elsewhere—to export power into Canada. *See, e.g.,* Ex. 95 (Order EA-365-C, October 21, 2025). In doing so, DOE specifically found that "wholesale energy markets are sufficiently robust to make supplies available to exporters." *Id*. at 4. DOE's October actions directly contradict the Order and further illustrate its arbitrary nature.

[19] Washington again disputes that these assessments constitute an "emergency" as contemplated by section 202(c). In any event, the NERC assessment was crafted *before* actual conditions in the Pacific Northwest were known, a fact that DOE fails to address. The Pacific Northwest has experienced historic rain events throughout the fall and now early winter. Ex. 41 at ¶¶ 8-9. Reservoirs are at capacity and hydropower capacity is expected to operate well above demand for the foreseeable future. *Id*.

explicitly acknowledges imported power could meet WECC Northwest's needs in the unlikely event of such a weather event knocking local resources offline. *See* Ex. 2 at 37 (acknowledging that "external assistance" can be used to maintain reserves in the event of "[a]bove-normal peak demand combined with high generator outages in extreme conditions"). As discussed above, imports have been highly successful in meeting the Pacific Northwest's power needs during adverse weather conditions, including an extreme cold weather event in 2024. Ex. 50 at ¶ 13. By disregarding imports, despite NERC's express recognition of this solution, the Department abandoned its statutory duty to choose the most effective emergency response.

And the failure to evaluate imports is difficult to understand given DOE's recent order permitting *exports* to Canada. *See, e.g.,* Ex. 95 (Order EA-365-C, October 21, 2025). For one, in doing so DOE specifically found that "wholesale energy markets are sufficiently robust to make supplies available to exporters." *Id*. at 4. Moreover, DOE also acknowledged that there are "always entities with broader responsibilities … such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system. *Id*. at 7; *see also* Ex. 50 at ¶ 15 (noting western reliability coordinators have authority to "alert all other balancing authorities and market participants of the status, and evaluate mitigation options such as re-dispatching generate, cancelling or recalling transmission and generation outages, and managing generation to address capacity"). DOE's October actions directly contradict the Order and further illustrate its arbitrary nature.

Furthermore, picking TransAlta Centralia to remain available to operate cannot constitute the most effective emergency response given the facility's operational constraints and performance record. On operational constraints, coal plants like TransAlta Centralia need

anywhere from 12 to 18 hours for startup—a timeframe fundamentally at odds with addressing any crisis requiring prompt action. Ex. 11 at ¶ 8. But even beyond these inherent limitations, TransAlta Centralia is a poor choice. The facility's boilers are nearly 60 years old. Since 2023, TransAlta Centralia has had 29 shut-downs, all but three of which were forced outages. Ex. 11 at ¶ 7. The facility's age and history of repeated unplanned outages in recent years severely undercut any claim that it represents a dependable emergency resource.

Finally, forcing TransAlta Centralia out of coal retirement cannot be the "best" choice for addressing the emergency and public interest even if DOE's general longer-term power supply concerns could be viewed as a valid basis for an emergency order, which they cannot. As noted, TransAlta Centralia is not shutting down—it is *expanding*. This years-in-the-making plan for the facility, that DOE's Order now threatens to disrupt, calls for a natural gas conversion of Unit 2 that will increase TransAlta Centralia's capacity by 30 megawatts and allow it to operate as a "peaker" plant—capacity and functionality that is necessary to prevent the type of emergency DOE's Order allegedly addresses. While the conversion of TransAlta Centralia might not be substantially impacted if the Order is limited to a 90-day period, DOE's practice in other states has been, citing long-term power needs, to roll the orders over for additional terms. Ex. 58 (Campbell Extension Order); Ex. 59 (Eddystone Extension Order). If that occurs here, DOE's Order will substantially worsen the region's power capacity, not improve it. *See, e.g.,* Ex. 41 at ¶¶ 9-13.

3. The Order's statement regarding "continuous operation" is arbitrary, capricious, and contrary to law

Citing reliability and other concerns, footnote 11 of the Order references TransAlta Centralia's "continuous operation … so long as the Secretary determines a shortage exists and

is likely to persist." Ex. 1 at 2, n. 11. As noted in Section V. above, DOE should clarify this statement to confirm that TransAlta Centralia simply maintain operational readiness, but not be directed to run unless and until there is an emergency loss of regional capacity that cannot be addressed by other resources, including power imports. In the absence of that clarification, however, DOE's order is arbitrary and capricious and contrary to section 202(c)'s express limitations on emergency orders.

First, any command that TransAlta Centralia generate power—at any level—is senseless and would constitute the apex of arbitrary administrative action. Putting aside the fact, as set out in Section VI.D.1, that the entities DOE identifies in the Order as directing Centralia's operation do not actually have the authority to direct that operation, any entity directing Centralia to fire up absent the actual need for that power would be, *at best*, a waste of resources and, *at worst*, potentially harmful to the regional grid.

This is because, absent an actual emergency loss of power, TransAlta Centralia power has nowhere to go in the area within which DOE claims to be mitigating the alleged emergency without shutting off other more economical and readily available sources. Section 202(c) does not authorize DOE to force any entity to purchase power involuntarily, and Centralia's contracts with Puget Sound Energy have terminated. Regional planning authorities have long presumed, and based forecasted needs on, not having Centralia capacity until it resumes operation as a natural gas facility in 2028. Washington's utilities are statutorily prohibited from providing coal power to their customers. *See, generally,* Chapter 19.405 RCW. And the BPA, by far the largest power provider in the Pacific Northwest, has no contracts with TransAlta Centralia and cannot take its power absent an *actual* emergency

power loss or other circumstances not applicable to Centralia. *See* 16 U.S.C. § 832d (setting out contracting limitations and authorizing purchases from public or private power systems only for "the mutual exchange of unused excess power … for the purpose of economical operation or of providing emergency or break-down relief"). Moreover, the price of Centralia's coal power is significantly higher than the wholesale energy market price. Ex. 41 at ¶¶ 14-15. This clearly indicates that, if Centralia is ordered to operate in the absence of an *actual* emergency, it will not be economical to dispatch in relation to other resources, and whomever is forced to purchase Centralia power will pay a higher price. *Id*.

Whatever energy needs DOE thinks it would alleviate, they are certainly not in the WECC Northwest. Rather, it appears the real beneficiary of these orders, per the President's direction, is the coal industry, not consumers or grid reliability. DOE's failure to consider the rate impacts to consumers from its Order, or whether the resulting rate will be just and reasonable, arbitrarily ignores an important aspect of the problem. *See* 16 U.S.C. § 824d(a) (stating unjust or unreasonable rates are unlawful).

Second, an order of continuous operation is also contrary to clear limitations on DOE's exercise of section 202(c) authority. Congress understood the danger of having section 202(c) orders providing blanket and long-term exemptions from environmental laws. As a result, Congress placed two important limits on section 202(c) orders, both of which are violated by the Order here.

The first of those is a time restraint. Section 202(c) requires that DOE ensure that any electric generation under an emergency order occurs "only during *hours* necessary to meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(2) (emphasis added). If

TransAlta Centralia was required to generate power, DOE's Order violates this statutory limit because operating Centralia in any capacity when it is not needed cannot possibly meet the requirement to only order those "*hours*" necessary to meet the emergency and serve the public interest. DOE cannot transform an hour-by-hour limitation into a blanket waiver through alleging "elevated risk" of tight operating reserves and "*potential* loss of power." Ex. 1 at 1, 3.

DOE's Order also violates section 202(c)'s environmental limitations. Section 202(c)(2) requires 202(c) orders comply with environmental laws and minimize any adverse environmental impacts "to the maximum extent practicable." 16 U.S.C. § 824a(c)(2). While DOE's Order makes no attempt to even identify those impacts here, they are evident. TransAlta Centralia is subject to air operating permits regulating a host of contaminants dangerous to both human health and the environment. Ex. 11 at ¶ 5. Significantly, Centralia has had documented issues with both carbon monoxide and particulate emissions, regularly requiring the plant to operate at limited capacity in order to meet safe emission requirements. *Id*. at ¶ 9. As discussed in Section III above, operating Centralia will also directly violate Washington and federal law and enforcement orders issued by the Department of Ecology. This includes controls required to meet visibility and regional haze requirements under the Federal Clean Air Act. *See, e.g.*, Ex. 7 at 4; Ex. 8 at 3.

To be sure, the Order makes gestures towards "minimizing environmental impacts" by limiting operation to whenever Centralia is "available to operate" at the direction of the Balancing Authority or the Reliability Coordinator. Ex. 1 at 3-4. But if DOE intends "available to operate" as a command that Centralia operates continuously—regardless of any actual need for Centralia power—DOE's Order violates the requirement to ensure environmental impacts

are "minimized." 16 U.S.C. § 824a(c)(2). In other words, it is impossible for an order requiring Centralia to run continuously *and for no apparent reason* to be seen as minimizing environmental impacts "to the maximum extent practicable." *Id*. Any command otherwise violates section 202(c)(2). *See* 16 U.S.C. § 824a(c)(2).

4. The Order will destabilize the very energy grid it purports to protect.

Washington utilities are subject to significant reporting and planning requirements. Under Washington law, utilities with 25,00 customers or more, like Puget Sound Energy, must develop, and periodically update integrated resource plans and file updates to those plans every two years. RCW 19.280.030; Ex. 51 at ¶ 7. All Washington's electric utilities must file their integrated resource plans with the Washington UTC, which may approve, reject, or approve plans with conditions. RCW. 19.280.040(1).

Integrated resource plans are subject to substantial vetting prior to filing. No later than fifteen months before the plans are due to the Commission, the utility must file a work plan that includes input from its advisory groups. WAC 408-100-625(2). Four months prior to the due date, the utility must file a draft plan, including its preferred portfolio, supporting analyses, and all potential scenarios and sensitivities. WAC 480-07-625(3). Once a final plan is filed, a diverse group of stakeholders analyze, review, and comment on these plans.

The content of integrated resource plans in Washington is robust, with an eye toward keeping the lights on in periods of high demand. Utilities must develop a long-term "preferred" portfolio and support that portfolio with an analysis of how it plans to meet hourly load, with all available resources, in a cost-effective manner while ensuring reliability and resource adequacy. WAC 480-100-620(11). In Washington, integrated resource planning

takes place over a twenty-year time horizon. RCW 19.280.030; Ex. 51 at ¶ 7. The objective of an IRP is to ensure a utility's resource portfolio is the least cost, least risk option. Robust resource planning is critical for utilities to make investment decisions that are reasonable, prudent, and in the public interest. *Id* . The planned retirement of TransAlta's Centralia coal plant occurs in this resource planning context.

As noted, Puget Sound Energy—and the region as a whole—has long planned for the retirement of the Centralia coal plant. In 2012, Puget Sound Energy entered a "coal transition" power purchase agreement with TransAlta pursuant to S.B. 5769. RCW 80.80.010(5). Puget Sound Energy entered this agreement with an understanding that Centralia would leave its resource stack after December 31, 2025. Puget Sound Energy petitioned the Washington UTC for approval of this agreement. After robust litigation, the UTC concluded the coal-transition agreement—set to expire on December 31, 2025—was in the public interest. *Id.*, *See* Ex. 98 (*In the Matter of the Petition of Puget Sound Energy, Inc*., 304 P.U.R.4th 42, 2013 WL 139618 (Jan. 9, 2013)).

After the entry of the UTC's order, the retirement of TransAlta became a planning assumption for Puget Sound Energy. As set out in Section VI.C.4 *supra*, Puget Sound Energy has filed *five* integrated resource plans or progress reports since the original Centralia plan was approved. Ex. 51 at ¶ 8. None of Puget Sound Energy's IRPs contemplated a long-term coal contract post-2025. *Id*. Each IRP was reviewed and approved as described above. Puget Sound Energy, the Commission, and interested stakeholders reviewed these plans to ensure that, among other things, resource adequacy standards were met. The resource planning process worked as it was supposed to do. *See* Ex. 53 at ¶ 8.

To that very point, the Puget Sound Energy/TransAlta deal to convert the retiring plant to a simple cycle natural gas plant to meet the future needs of the region's renewable-heavy resource mix has been finalized. Ex. 66 (TransAlta Centralia to Transition from Coal to Natural Gas, December 10, 2025). This has long been Puget Sound Energy's plan to replace the coal power that was being removed from its system. In the company's 2024 General Rate Case, a Puget Sound Energy witness testified that the company would meet any potential resource adequacy challenges, in part, using its existing gas-fired generation fleet to meet reliability and resource adequacy deficits for the region as a whole caused by the removal of coal-fired generation. Ex. 51 at ¶ 121. The closure of Centralia is not a loss of needed power, but the replacement of one firm power resource for another, as part of a larger, region-wide resource adequacy plan.

Yet, in its Order, DOE has thrown this entire process into chaos and displaced the judgment of local regulators in favor of coal-fired generation. In doing so, DOE has needlessly injected uncertainty into the local energy market, risking the destabilization of the Northwest's energy grid. This is particularly troubling given that a failure in resource planning leads to high costs and, critically, over- or under-procurement.

This concern is immediately apparent in the Order. Setting aside the fact that the Northwest is experiencing an energy *surplus* this winter due to historic rains, the Order cites the NERC Winter Reliability Assessment finding that winter peak demand is forecast to be 2.9 GW higher this year compared to last year. Ex. 1 at 1. As currently configured, however, Centralia is a coal baseload generating facility operating on entirely different economic principles than a plant intended to meet peak demand. Allowing for the planned retirement

and conversion represents a far greater contribution to resource adequacy than the forced operation of an expensive, aging coal plant.

As currently operating, Centralia is also ill-suited to meet Washington's peak resource needs for several additional reasons, including its status as a merchant plant. This means Centralia operates only when it is profitable to do so—i.e., when there is a buyer in the market. Ex. 11 at ¶ 6. As noted above, Washington utilities cannot include coal resources in rates after December 31, 2025, and other states functionally exclude coal power or are in the process of a phase-out. This significantly limits the number of purchasers in the region. RCW 19.405.030(1). Centralia is also less efficient and more unreliable than the gas plant it will ultimately become. Between 2023 and 2025, the plant was offline for nearly 5,000 hours—over 10% of its hours over a three-year period. Ex. 11 at ¶¶ 6-7. Most of these outages were forced outages. *Id.*

Centralia's merchant status also contributes to the plant's inflexibility. The plant will spend most of its time offline and will need to be restarted each time an entity purchases power. Ex. 11 at ¶ 6. In such an event, the plant will take up to eighteen hours from startup to a load of just 300 MW. *Id.* at ¶ 7. By ordering the unit to continue to run, DOE effectively deprives the region of a much-needed, efficient, 700 MW gas peaking resource. Ex. 50 at ¶ 11, n.1. It is also unclear how well Centralia could operate as a coal plant in a manner that can meet peak demand given the significant ramp-up time associated with coal plants. While the planned conversion to a natural gas plant may not fully alleviate the ramp-up issues for Centralia, those issues can be addressed over the next two years to maximize the ability of Centralia to enhance reliability in the region.

Put simply, the region did not plan for Centralia to continue operating past December 31, 2025. Washington electric utilities anticipated the plant's retirement and planned for it in their IRPs. In the case of Puget Sound Energy, its IRPs anticipated replacing Centralia's power with power from other sources. As stated above, these plans were vetted by local stakeholders and approved by regulators.

DOE has ignored this process and has now called every electric utility's integrated resource plan into question. As coal is phased out of Washington rates, coal plants will be retired. Utilities must be allowed to plan for coal retirements and regulators must have the flexibility to approve those plans. Ultimately, DOE's actions in this case are more than simply disruptive, they are destructive. They undermine prudent utility practice and disregard local decision making. The Order is a recipe for chaos in the local power system and, indeed, has the potential to destabilize the very grid it seeks to protect by denying the region a needed resource. The Order does not contend the region lacks sufficient baseload capacity, and indeed it recognizes the region has "sufficient capacity in the area for expected peak conditions." Ex. 1 at 1. However, ordering the Centralia plant to remain open as a coal plant threatens the creation of a much-needed resource necessary to meet the challenges the Order contends the Northwest is ill equipped to face—extreme weather or a sudden increase in demand. *Id.* In doing so, the Order recklessly puts the region in jeopardy.

5. The Order is an unlawful pretext for buttressing the President's policy goal of supporting the coal industry

The Order is not merely a questionable policy choice. It is a naked effort to boost demand for the coal industry that the Trump Administration favors, resting on the false pretext of an emergency. The Order is unrooted in any emergency and its actual endgame—coal

boosterism—cannot withstand legal scrutiny. Because the Order is pretextual, it should be withdrawn.

Agency action should be set aside as arbitrary and capricious when it rests on a "pretextual" reason that is "incongruent with what the record reveals about the agency's priorities and decisionmaking process." *Dep't of Commerce v. New York*, 588 U.S. at 782. Courts are "not required to exhibit a naiveté from which ordinary citizens are free," and they must "ensure that agencies offer genuine justifications for important decisions." *Id.* at 785. For example, in *Department of Commerce v. New York*, the Supreme Court invalidated the administration's attempt to add a citizenship question to the 2020 census. *Id*. The Court held that the justification proffered by the administration—to help enforce the Voting Rights Act, not to suppress population counts in districts with larger numbers of noncitizens—was mere pretext and a "distraction," not an explanation of the "reasoned decisionmaking" that the administration claimed. *Id*. "[D]ecisions featuring unjustifiable bias or partisanship are precisely the types of agency actions that 'would work a violation of the arbitrary-and-capricious standard.'" *Level the Playing Field v. FEC*, 961 F.3d 462, 464 (D.C. Cir. 2020) (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)); *see also Rhode Island State Council of Churches v. Rollins*, 25-CV-569-JJM-AEM, 2025 WL 3111213, at *10 (D.R.I. Nov. 6, 2025) (issuing a restraining order because stated reason seemed "entirely 'pretextual'" in light of "numerous statements" making clear that agency action was "for political reasons").

As explained above, the "emergency" invoked by DOE does not exist. Even if it did, continuing TransAlta Centralia operations is not the remedy. A brief examination of the Trump Administration's public statements from 2025 alone shows the "emergency" is mere

pretext for the true objective, unstated in the Order: to promote the coal mining industry by stoking demand for coal. This disconnect between the invoked emergency and the real goal requires the same scrutiny applied in *Department of Commerce* and subsequent cases. Just as the Commerce Department's rationale masked an attempt to suppress census counts in certain districts, DOE's grid "emergency" rationale finds its true lodestar in an attempt to spur demand for one of the Trump Administration's favored industries.

Coal production in the United States has steadily fallen from 2008 to 2024, with coal-fired power declining by 67% over the same period as it faced increasing competition from natural gas and renewable energy. Ex. 68 (E&E News, *Trump has vowed to make coal king again. How's it going?*, September 26, 2025). Trump sought to reverse the trend—not just by expanding coal mining, but also by juicing demand for coal. On April 8, 2025, and among other orders purporting to address energy needs, President Trump issued an Executive Order that removed barriers to coal mining and rescinded policies that impede the consumption of coal. *See* 90 Fed. Reg. 15517. At the signing ceremony, President Trump proclaimed an energy policy aimed at "bringing back an industry that was abandoned" and "ending Joe Biden's war on beautiful clean coal once and for all," promising that "[a]ll those plants that have been closed are going to be opened." Fox 29 Philadelphia, *FULL SIGNING: President Trump signs executive orders on coal mining* (YouTube, April 8, 2025).[20] This requires not only increasing production but also boosting demand, and that is what the President has set

[20] https://www.youtube.com/watch?v=1TfJUn2VxM4.

out to do in no uncertain terms: "We're going to guarantee that we have a strong [coal] business for many years to come."[21]

This boosterism is precisely what the administration is engaged in with its current section 202(c) orders. Since April 2025, the Trump Administration has issued multiple orders expanding coal mining and cancelling long-planned closures of coal-burning power plants, all while denigrating competitors of coal (e.g., renewable energy) that could add more electricity to the grid. *See, e.g.*, Ex. 69 (U.S. Dept. of Interior Press Release, *Interior Approves Mining Plan to Unlock 14.5 Million Tons of Coal*, August 8, 2025); Ex. 27; *see also* Forbes Breaking News, *Trump Goes on Sudden Tirade Against Windmills During Meeting With EU President Ursula Von Der Leyen,* (YouTube, July 27, 2025) ("we will not allow a windmill to be built in the United States").[22]

The administration's policies do not spring from nowhere but were instead designed to prop up an industry that donated millions of dollars to Mr. Trump's campaign. Ex. 70 at 20 (New York Times, *Hundreds of Big Post-Election Donors Have Benefited From Trump's Return to Office*, December 22, 2025) ("About two dozen companies with interests in oil, gas and coal donated at least $41 million."). And so, at the coal industry's behest, the Trump Administration is offering "white glove service" and "concierge service" to companies interested in "keeping coal plants open" via a "little tiger team . . . put together very particularly with the president's priorities in mind on energy," namely "keeping coal plants open." Ex. 71 (Washington Post, *White House offers "concierge" service to fossil fuel firms,*

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[21] *Id.* at 19:58.
[22] https://www.youtube.com/watch?v=1Asznj3uWKA at 0:06.

official says, October 7, 2025). At the expense of the health of coal miners, the Trump Administration has given owners of the coal industry a windfall and eradicated programs within HHS designed to research and protect the health and safety of coal miners—including NIOSH's Spokane Mining Research Division in Washington State—or stalled regulatory efforts to limit miners' exposure to toxic silica dust. Ex. 72 (The Hill, *Trump admin will reconsider part of rule to protect miners from lung diseases*, December 1, 2025); *See also* Ex. 75 (Notice to Stakeholders). The President has gone so far as to require staffers to always precede every utterance of the word "coal" with "clean and beautiful" because he feels the coal industry "needs a little help public relations wise." Ex. 73 (E&E News, *Trump wants mining. Federal mine safety workers are on the chopping block*, September 5, 2025); *See also State of New York v. Kennedy*, 1:25-cv-00196, (D.R.I. May 09, 2025) ECF Nos. 44, 55, 84 (declarations from NIOSH employees detailing the Trump Administration's destruction of NIOSH's Mining Research Divisions in Spokane and Pittsburgh).

Finally, the Order also advances the Administration's policy of discriminating against alternative energy sources to advance the extra-statutory motive of protecting the coal industry at consumer expense, which is contrary to express goals of the Federal Power Act. *See* 16 U.S.C. §§ 824d, 824e; *see also* Ex. 35 at 27-29. Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential. *See id*. Purporting to justify a section 202(c) order for a coal plant that is not needed and ignoring other viable, cheaper methods to preserve grid reliability is likely to result in unjust and unreasonable rates.

Ultimately, the Order is founded in the Trump Administration's desire to boost the consumption of coal. Knowing that favoritism toward the coal mining industry would not qualify as an emergency under section 202(c), DOE contrived an electrical grid emergency. But "contrived reasons . . . defeat the purpose" of the "reasoned explanation requirement." *Dep't of Commerce v. New York*, 588 U.S. at 785. Moreover, even the Trump Administration's contrived reasons do not make sense as the continued operation of Centralia will most likely do nothing to abate the supposed emergency. The Order is based on a pretext, in violation of both the APA and multiple sections of the Federal Power Act. It should be withdrawn on those grounds.

E. The Order Will Undermine the Northwest's Energy Market, Increase Electricity Rates, and Harm Consumers

As noted, Congress explicitly limited DOE to actions under 202(c) to "meet the emergency and *serve the public interest*." 16 U.S.C. § 824a(c)(1). Here, the public interest is further not served by destabilizing the regional energy market in the short and long term, unnecessarily increasing customer rates amid an ever more dire affordability crisis and refiring a heavily polluting plant on the eve of its retirement. The true impact of DOE's Order will create future energy shortages that may have otherwise been mitigated—all while forcing the American public to foot the bill. DOE's Order serves the private coal industry, not the public interest. To use Secretary Wright's words, DOE's 202(c) Order here and elsewhere are "radical nonsense policies that dramatically raise prices on the American people." Ex. 90 (White House, *What They Are Saying: President Trump Stops Radical Environmentalism to Generate Power for the Columbia River Basin,* June 13, 2025). This further renders the order arbitrary and capricious because it utterly fails to consider the immediate disruption it causes

to the Northwest energy market. *See Michigan*, 576 U.S. at 753 (an agency must "pay attention to the advantages *and* the disadvantages of [its] decisions").

1. DOE's Order will cause immediate disruption to the Northwest energy market because it could force curtailment of cheaper and abundant hydropower.

The Northwest is characterized by water—coming down as rain in the western lowlands and snow in the mountains—all of which eventually flows through the Columbia River Basin, the fourth largest river basin in North America. Ex. 76 (Columbia River Basin Dams). The Columbia River produces more hydropower than any other river in North America. Ex. 77 (Bonneville Power Administration, Resources). Thanks to this rich natural resource, hydropower is the region's single largest source of power. Ex. 78 (Bonneville Power Administration, Hydropower Flows Here). The Army Corps of Engineers and Bureau of Reclamation operate 31 federally-owned hydroelectric dams throughout the region, which the BPA markets to utility companies as a wholesaler. 16 U.S.C. § 832, 838. BPA provides this power at cost to utilities, prioritizing sales to public and cooperative customers. 16 U.S.C. § 832.

When water flow is low, BPA may purchase power on the market to supplement its portfolio and meet the demands of its preference customers—primarily public entities. 16 U.S.C. § 832c-d. As with hydropower generated by the federally-owed dams, power purchased by BPA from the market is also provided to utilities at cost. 16 U.S.C. § 832d. That cost, however, is often much higher than power the federal government can generate from its own dams using low-cost renewable resources like water. Ex. 79 (Newsroom, *BPA maintains strong financial position despite challenging water year*, November 13, 2025). If water flow

is high, purchases from the market are minimal or unnecessary. And, as of January 1, 2026, purchases of coal-fired power are prohibited in Washington State. RCW 19.405.030(1).

In December 2025, Washington State experienced historic rainfall and flooding. Ex. 80 (NASA, *Pacific Moisture Drenches the U.S. Northwest*, December 12, 2025). In response, the Federal Emergency Management Agency (FEMA) issued an emergency declaration for Washington State on December 12, 2025. Ex 54 (FEMA emergency declaration for WA floods). FEMA and the U.S. Coast Guard sent teams to Washington to assist emergency response to "some of the most significant storms, heavy rain and flooding in the state's history." Ex. 82 (FEMA, *Federal Teams Support State-Led Response to Historic Washington Severe Storms and Flooding*, December 23, 2025). As a result of the historic rainfall, the capacity for production of hydroelectric power in December 2025 was high, with most dams under BPA's control full and many over their spillway level. Ex. 41 at ¶¶ 9,10.

Yet, just four days later, DOE issued the current Order, effectively seeking to compel an additional energy source into a market that is currently oversaturated. *See* Ex. 1. When the regional energy market is over resourced, some resources must be curtailed to prevent grid overload which can lead to equipment failures and blackouts. Collin Wilfong, Robert Bullington, *Charging Forward: Accelerating Long-Term Energy Storage Development*, 23 Vt. J. Envtl L. 156 at 163 (2022) ("When there is a surplus of electric power on the grid, grid operators sometimes issue curtailment orders compelling wind or solar generators to temporarily reduce the amount of power they are feeding onto the grid to help avoid grid overloads.")Here, it appears that DOE's order would prioritize coal over hydropower. *See* Ex. 1. This both undermines the Northwest energy market and favors ramping up private fossil

fuel production over maintaining operation of federally-owned hydropower dams operated by the Army Corps of Engineers.

This move is not even consistent with the Administration's own policy statements and actions. For example, on June 12, 2025, the President Trump revoked a Presidential Memorandum issued by then-President Joe Biden intended to restore native fish populations in the Columbia River Basin. Ex. 83 (Stopping Radical Environmentalism to Generate Power for the Columbia River Basin). A principal concern cited by President Trump was the "secure, reliable, and affordable hydroelectric generating capacity" for the Columbia River Basin. *Id.* The Secretary lauded the action, referring to the "tremendous assets" and "high-value electricity" hydropower brought to the region while decrying the "radical nonsense policies [of the prior administration] that dramatically raise prices on the American people." In direct contradiction of that June 2025 revocation, DOE now seeks to displace low-cost hydropower that can be produced with existing infrastructure in favor of expensive coal.

Simply put, if coal fired power is somehow forced into the energy market it will upset the balance of what is available from BPA and could force the Army Corps of Engineers to shut off perfectly functioning hydropower resources to prevent grid failure. These hydropower resources cost less money to produce and, because they are sold at cost to utility customers, those customers may not have access to the same allocation of lower cost resources. Adding coal fired power to the energy market unnecessarily drives up prices and undermines the balance of the regional energy market. And, as discussed above, there may not be any willing buyers of coal power. This could lead to a regional energy market crisis where low-cost hydroelectricity is curtailed to allow coal-fired electricity onto the grid, but with no purchasers

of coal, the respective supply and demand of hydropower and coal would be unstable and imbalanced.

2. The Order will cause long-term disruption to the Northwest energy market because it will delay conversion of the TransAlta plant to natural gas which is integral to the region's long term resource planning

As noted, the careful planning behind the transition of TransAlta's Centralia plant from coal to natural gas has been a decade in the planning. Ex. 51 at ¶ 9. Centralia's transition, scheduled to come online in late 2028, aligned with the region's expected increased energy needs for the winter 2028–29 season. Ex. 41 at ¶¶ 4, 6; Ex. 3. DOE's Order threatens to indefinitely delay this transition, disrupting the planned conversion to natural gas that all participants in energy market would have benefitted from. Ex. 51 at ¶¶ 23, 25.

Moreover, because the state of the emergency the order is premised upon is unclear, participants in the northwest energy market are left to speculate when and under what circumstances there would cease to be an "emergency." Pushing back the timeline of the plant's transition to natural gas even 90 days risks the plant not being ready to produce electricity as a natural gas plant for the winter 2028-29 season that the E3 PowerPoint identified as critical. Ex. 41 at ¶¶ 4, 6. Any delays beyond the initial 90-day order will all but guarantee it. TransAlta's Centralia plant coal operations must wind down in order for the plant to begin retrofits to transition to natural gas. Ex. 51 at ¶¶ 23, 25. That retrofit process is now on hold indefinitely. *Id*.

The full impact of delaying or losing a future natural gas resource that has been expected for over a decade is difficult to measure. What is known is this: the future energy market in the Northwest for years to come, particularly in the winter 2028–29, is now

unbalanced and disrupted by DOE's unlawful meddling with markets it apparently does not even fully understand.

3. The inevitable outcome of DOE's Order is increased electricity rates that will be borne by Americans already facing an affordability crisis

A necessary corollary to ordering the operation of a coal plant that was days away from retirement is unexpected costs. Regulated utilities pass on most costs to consumers through increased rates. The Order directs TransAlta to file tariff revisions or waivers with the Federal Energy Regulatory Commission (FERC) for rate recovery pursuant to 16 U.S.C. § 824a(c). Though a precise amount or date of customer rate impact is not known, for the reasons described above, the costs are expected to be high. Whether coal fired power is placed onto the grid and forces the curtailment of cheaper hydropower, or the coal plant is simply standing by with workers, machines, and coal at the ready, both will generate significant costs.

This is especially troubling given the fact that utility bills are an increasing burden on ratepayers in Washington State and beyond. According to the U.S. Energy Information Administration (EIA), Ex. 84 (EIA, *Electricity Data Browser*), Washington retail electricity prices increased by 12.3 percent for residential customers between August 2024 and August 2025, significantly higher than the 3.1 percent rate of inflation for all items less food and energy over the same period. Ex. 85 (U.S. Bureau of Labor Statistics, *Consumer prices up 2.9 percent from August 2024 to August 2025*, September 17, 2025). This rise in utility prices, paired with the rising housing prices and lack of affordable housing options, Ex. 86 (Washington State Dept. of Commerce, *Report: Lack of affordable housing options reaches critical levels in communities throughout Washington state*, May 13, 2024), details a worsening affordability crisis for Washington families. A recent non-profit report states that

in 2023, 38 percent of Washington families were unable to afford basic needs, up 4 percentage points from 2022. Ex. 87 (Trends in Financial Hardship). Adding superfluous expenses to Washingtonians' bills will only deepen the crisis, even while cheap hydropower is ready and available. And TransAlta Centralia's conversion to natural gas—now potentially indefinitely derailed by DOE's Order—was intended as a low-cost, high-reward method of supplying "peaker" capacity and utility without the usual impacts to ratepayers that constructing a new peaker plant would otherwise entail. *See* Ex. 20; Ex. 49 at ¶ 5.

Rate increases and inflation will force utility customers to make affordability choices that impact their ability to sustain a decent lifestyle, particularly at lower income levels. DOE's Order is a wholly-avoidable impact to consumers. DOE's failure to consider these rate impacts and weigh them against its perceived reliability needs, especially those based on uncertain projections of demand far into the future, is arbitrary, capricious, and contrary to the Federal Power Act's intent to protect consumers from unreasonable costs.

4. Continuing to run Centralia will release toxic air pollutants that otherwise would not have been released, resulting in negative human health impacts

TransAlta Centralia is a significant source of pollution in Washington State. Coal-fired power plants like Centralia are major sources of air pollutants that are known or suspected to cause cancer or other serious health effects like respiratory illness and premature death. Ex. 10 at ¶ 5; Ex. 52 at ¶ 9; *see* 42 U.S.C. § 7412. Common pollutants from coal-fired power plants include sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), nitrogen oxides (NO_x), dioxins, polycyclic aromatic hydrocarbons, and mercury and other heavy metals. Ex. 10 at ¶ 5; Ex. 52 at ¶ 9; *see also* Ex. 89. And, when the Washington State Legislature ordered the phasing out of the Plant via the TransAlta Energy Transition Bill, S.B. 5769 (2011), Centralia was the

largest single source greenhouse gas emissions in Washington. S.B. 5769 § 101(2). Moreover, pollution concerns are not limited to aerial emissions. Recent remedial investigations of the Plant conducted by TransAlta found six heavy metal contaminants in the soil of concern, nine heavy metal contaminants in the groundwater of concern, and six heavy metal contaminants of concern in the sediment at the Plant that were above applicable cleanup levels. *See* Ex. 52-2 (In the Matter of Remedial Action by: TransAlta Centralia Generation LLC for: TransAlta Centralia Agreed Order, No. DE 24235, December 29, 2025) at 5.12; Ex. 52 at ¶ 7.

As a result, the continued operation of Centralia will have direct negative human health impacts. By preventing the Centralia from ceasing operations, will directly cause emissions impacts that otherwise would have been avoided. For example, it is estimated that ceasing operations of the Plant would have reduced emissions for $PM_{2.5}$, SO_2, and NO_x by hundreds and thousands of tons per year. Ex. 10 at ¶ 7. Impacts from these emissions have been assessed by the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). Ex. 10 at ¶ 9. COBRA estimated that the continued operation of Centralia Unit 2 using coal would contribute to:

- 9 to 13 early deaths;
- 3 nonfatal heart attacks;
- 53 cases of asthma onset;
- 8,400 symptoms of asthma;
- 3,500 minor restricted activity days for Washingtonians;
- 3,800 school loss days for Washington children;

- 590 work loss days for Washington workers; and
- $140 million to $210 million cost to society.

Ex. 10 at ¶ 10. These estimates do not account for emissions resulting from requisite transport of coal to TransAlta Centralia or the public health impacts on the miners who produce that coal. Ex. 10 at ¶ 7; *see also*, supra Section VI.C.5. While there will be emissions from the planned conversion operation from coal to natural gas, those emissions would be significantly less than the baseline rate emissions if the plant continued to operate using coal. Ex. 10 at ¶¶ 11, 12.

And the harms and costs estimated by COBRA do not account for emissions due to Centralia operating outside the bounds of its environmental permits. For example, in December 2025, the Plant received two Notices of Violation (NOV) related to excess emissions. Ex. 11 at ¶ 12. The first NOV was related to excess emissions from the fly ash unloading baghouse and the second NOV for not fully engaging all relevant pollution control equipment prior to firing coal on startups. Ex. 11 at ¶ 12. These violations are a result of reduced staffing or maintenance in anticipation of the December 31, 2025, shutdown. *Id*. The Order creates uncertainty that may make it difficult to retain sufficient qualified staff to prevent future oversights. *Id*. There is a high chance these problems, and more, will continue should Centralia run per the Order, exacerbating negative environmental health impacts.

The harms and costs from operating the Plant per the Order will lead to unnecessary harms to human health. These harms are completely preventable and can be avoided if the Order is withdrawn.

F. DOE's Order Fails to Comply With NEPA

NEPA requires all federal agencies to develop an environmental impact statement for any major federal action significantly affecting the quality of the human environment. 42 U.S.C. § 4332(2)(C). As described above, continued operation of Centralia will result in significantly higher emissions of particulate matter, sulfur dioxide, nitrogen oxides, and other greenhouse gases with expected adverse health impacts to the surrounding communities. *See, e.g.,* Ex. 10 at ¶¶ 7, 10. Thus, the Order here constitutes a major federal action that will significantly affect the human environment. 42 U.S.C. § 4336e(10). To comply with NEPA, DOE must develop an environmental impact statement, or if it's not obvious whether the action will have a significant impact on the environment, an environmental assessment. 42 U.S.C. § 4336(2). DOE did neither.

Moreover, no categorical exclusion applies to the Order. In the past, DOE has pointed to categorical exclusion B4.4 for "power management activities" to avoid performing an environmental analysis under NEPA. 10 C.F.R. § Pt. 1021, App. B. However, categorical exclusion B4.4 is only available when the "operations of generating projects would remain within normal operating limits." 10 C.F.R. § Pt. 1021, App. B4.4. The Order here mandates that Centralia operate beyond its normal permitted limits—limits that, at this point, would otherwise be *zero*.

Finally, while DOE's rules permit it to take emergency actions without first complying with NEPA, that is only so long as it immediately consults with the Council on Environmental Quality to make alternative arrangements for emergency actions that have significant environmental impacts. 10 C.F.R. § 1021.103. When DOE issued 202(c) orders in the past, it

prepared Special Environmental Analyses after the fact. Ex. 91 (Special Environmental Analysis of BANC during 202(c) Emergency Order Operations between Sept. 4, 2022 and Sept. 8, 2022). However, those cases involved sudden emergencies where DOE did not have notice to develop environmental analyses. Here, the Order is in reaction to the perceived capacity challenges caused by the retirement of the Centralia Coal Plant on December 31, 2025. The retirement of Centralia was planned in 2011. S.B. 5769; Ex. 5. Energy had ample time to conduct an environmental analysis to comply with NEPA. Therefore, the Order unjustifiably violates NEPA.

VII. REQUEST FOR STAY

Washington State further moves DOE for a stay of the Order until judicial review has concluded. 18 C.F.R. § 385,212,132. DOE has the authority to issue a stay under the Administrative Procedure Act where "justice so requires." 5 U.S.C. § 705.

To determine whether to grant a request for stay, agencies consider: (1) whether the requesting party will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

A. Washington State Will Suffer Irreparable Injury Without A Stay

A stay is necessary to prevent irreparable harm to Washington State caused by the Order. Injuries must be actual, certain, imminent, and beyond remediation. *Mexichem*

Specialty Resins, Inc. v. EPA, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (identifying that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").

Economic injury is irreparable only where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958). Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

The Order imposes costs on Washington ratepayers that may not be recoverable through future litigation and would not have otherwise been expended absent the Order. Assuming TransAlta complies with the Order,[23] it will expend considerable costs preparing the plant for refiring—if the plant is idle but available to operate *or* actively producing coal-fired power. *See supra* Section III at 10-11, Section IV.H.1. TransAlta will generate staffing and overhead expenses under either scenario. Firing up the plant and transmitting electricity will further increase expenses. And plainly, coal is more expensive. Ex. 41 at ¶ 15 ("Under its current Purchase Power Agreement (PPA), the energy price from Centralia's coal is

[23] There is no indication that TransAlta will not comply with the Order, to the extent it understands what the Order requires it to do.

significantly higher than the wholesale energy market price. Specifically, under the current contract, Puget Sound Energy pays $62.04 per MWh, while the wholesale market price is $54.32 per MWh."). The Order directs TransAlta to recover its expenses through a FERC tariff revision. Order at 4; 16 U.S.C. § 824a(c). Neither the Order nor the statute identify a mechanism for "corrective relief" should the Order be found unlawful. As there is no clear recourse to recovering these costs should Washington State prevail in its challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases.

Environmental injury is inevitable whether the Order requires TransAlta to immediately operate Centralia as a coal plant, or it operates intermittently from a stand-by posture. As described in the Rehearing Request, Washington residents will suffer environmental health and environmental harms because of the Order. *See supra* Section III at 8, Section IV.H.3. TransAlta's Centralia Coal Plant is a significant source of particulate matter, sulfur dioxide, and nitrogen oxides. Ex. 10 at ¶ 7. Those emissions are known to adversely impact human health. Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the failure to cease operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million in health care costs and lost economic activity in Washington annually. Ex. 10 at ¶ 10. Further, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12; Ex. 13. A local clean air agency issued Centralia two notices of violation for exceeding emissions limits in December 2025. Ex. 11 at ¶ 12. Emissions are expected to be even higher if Centralia cannot operate at a lower load

or make necessary repairs, or cease operations entirely as it had planned to do prior to the Order. Ex. 11 at ¶ 11. Because the environmental injury to Washington State and its residents cannot be adequately remedied and may be permanent or long duration and is sufficiently likely, a stay pending judicial review is necessary.

B. A Stay Would Not Substantially Harm Other Parties

No parties would be harmed by a stay of the Order because no emergency exists and the Order was never needed to begin with. As detailed above, an order under 202(c) must be limited to circumstances that are imminent and unforeseen. *See supra* VI.A. DOE's Order's provides no evidence to support a claim of an imminent emergency and references potential *future* grid unreliability. *See supra* VI.C.1. The State supplies substantial evidence to support the absence of an energy emergency. Because no current emergency exists, no other party could be harmed. Not forcing the deployment of coal plant that is not needed harms no one. A stay would not disrupt the local energy market or impair the provision of electricity to customers.

C. A Stay is in the Public Interest

DOE's Order is contrary to the public interest. A stay will prevent any potential harm to the public that will be caused by the Order. Principally, the Order fails to meet the public interest standard under the Act DOE relies upon, i.e., 16 U.S.C. § 824a(c)(1), in bringing the Order. *See supra* VI.D.2. Further, if a true energy emergency existed, the public interest would not be served by an aging, unreliable coal plant that requires 12-18 hours to start up. Ex. 11 at ¶¶ 7, 8. DOE's Order has the potential to throw the regional energy market into short-term

and long-term uncertainty, both of which could have adverse consequences for energy users—the public. *See supra* VI.E.1. A stay is in the public interest.

VIII. CONCLUSION

For the reasons set forth above, Washington respectfully requests that DOE grant intervention, grant rehearing, and rescind the Order in its entirety. In the alternative, Washington requests that DOE clarify that the Order directs readiness only and that TransAlta Centralia not operate in any capacity unless and until there is an actual energy shortage and where existing resources operated by WRAP participants, or imports from other regions, cannot meet demand.

Dated this 13th day of January, 2026.

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State of Washington

Request for Rehearing of Order No. 202-25-11

Index of Exhibits

No.	Exhibit Name	Document Name	URL
1	DOE Order No. 202-25-11	Department of Energy (DOE), Washington DC 20585, Order No. 202-25-11 (Dec. 16, 2025)	
2	NERC 2025–2026 Winter Reliability Assessment	North American Electric Reliability Corporation, 2025–2026 Winter Reliability Assessment (Nov. 2025)	
3	E3 Slide Deck	Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results, dated September 22, 2025	
4	DOE Resource Adequacy Report	DOE Resource Adequacy Report, Evaluating the Reiliability and Security of the U.S. Electric Grid (July 2025)	
5	Memorandum of Agreement	Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Dec. 23, 2011)	

No.	Exhibit Name	Document Name	URL
6	2017 Amended Memorandum of Agreement	First Amendment to Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Jul. 13, 2017)	
7	2011 BART Order	Dep't of Ecology Administrative Order, First Revision: Order No. 6426 (Dec. 13, 2011)	
8	2020 BART Order	Dep't of Ecology Administrative Order, Second Revision: Order No. 6426 (Jul. 29, 2020)	
9	Technical Support Data-2020 BART Order	Dep't of Ecology Technical Support Document for Second BART Order Revision, TransAlta Centralia Generation Plant (July 2020)	
10	Palcisko Declaration	Declaration of Gary Palcisko in Support of Request for Rehearing by State of Washington	
10-1	COBRA Data Coal v. Cease Operations	Total Health Benefits, Lewis County, Washington	

No.	Exhibit Name	Document Name	URL
10-2	COBRA Data Coal v. Natural Gas	Total Health Benefits, Lewis County, Washington	
10-3	2023 Emissions Inventory		
11	Lamoreaux Declaration	Declaration of Clinton Lamoreaux in Support of Request for Rehearing by State of Washington	
11-1	TransAlta Centralia Title V Quarterly Report First Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan. 1 - March 31, 2025	
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11-3	TransAlta Centralia Title V Quarterly Report Third Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2025	

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11-4	TransAlta Centralia Title V Quarterly Report First Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan 1 – March 31, 2024	
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11-9	TransAlta Centralia Title V Quarterly Report Second Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, Apr. 1 – Jun 30, 2023	
11-10	TransAlta Centralia Title V Quarterly Report Third Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2023	
11-11	TransAlta Centralia Title V Quarterly Report Fourth Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Fourth Quarter, Oct. 1 – Dec. 31, 2023	
11-12	Photograph of opacity readings	Photograph of opacity readings on Oct. 23, 2025	
11-13	Centralia Plant's 2022 U2 Boiler Tune-up Report	TransAlta Centralia U2 Boiler, 40 CFR 63 DDDDD Tune-Up Report (Oct. 3, 2022)	
11-14	Notice of Violation No. 10642, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Oct. 23, 2025	

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11-15	Notice of Violation No. 10643, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Jan 11, Mar. 4, Jun. 6, Jun. 11, Aug. 26, 2025	
12	Top 10 Stationary Sources of GHG Emissions in WA – 2022	Dep't of Ecology Data Base: Top 10 Stationary Sources of Greenhouse Emissions in Washington (2022)	
13	2023 EPA Top CO2 Emissions	U.S. Env't Prot. Agency, Greenhouse Gas Reporting Program (GHGRP), Top Washington Greenhouse Gas emissions sources for 2023, *GHGRP State and Tribal Fact Sheet* (last visited Jan. 6, 2026)	https://www.epa.gov/ghgreporting/ghgrp-state-and-tribal-fact-sheet
14	U.S. Energy Information – Start Up	U.S. Energy Information Administration, Owen Comstock, *About 25% of U.S. power plants can start up within an hour* (Nov. 19, 2020)	https://www.eia.gov/todayinenergy/detail.php?id=45956)

No.	Exhibit Name	Document Name	URL
15	Plant Job Underway	Centralia Daily Chronicle, *Plant Job Underway* (Jun. 14, 1968)	
16	2021 Title V Air Operating Permit	TransAlta Centralia Generation, LLC, Centralia Plant, Air Operating Permit SW-98-8-R5A, Southwest Clean Air Agency (Sep. 22, 2021)	
17	2021 Title V Air Operating Permit - Basis Statement		
18	U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860)		https://www.eia.gov/electricity/data/eia860/
19	2022 Visibility SIP	Washington Dep't of Ecology, Air Quality Program, *State Implementation Plan Revision, Second Regional Haze Plan* (2018 – 2028) (Jan. 2022)	

No.	Exhibit Name	Document Name	URL
20	TransAlta News Release Announcing Coal to Gas Conversion Project	TransAlta, Alberta Calgary, News Release, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/
21	TransAlta Permit Application	TransAlta Centralia Generation, LLC, *Prevention of Significant Deterioration Permit Application* (Dec. 2025)	
22	Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Long-term Resource Adequacy Meeting* (Nov. 19, 2025)	
23	2025 DOE 202(c) Orders	2025 DOE 202(c) Orders	https://www.energy.gov/ceser/2025-doe-202c-orders

No.	Exhibit Name	Document Name	URL
23-1	Order (Dec. 14, 2000)	U.S. Dep't of Energy, Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000) (California Energy Crisis in 2000)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-2	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-3	DOE Order No. 202-05-2 (Sep. 8, 2005)	DOE Order No. 202-05-2 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-4	DOE Order No. 202-08-1 (Sep. 14, 2008)	DOE Order No. 202-08-1 (Sep. 14, 2008) (Hurricane Ike)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-5	DOE Order No. 202-20-1 (Aug. 27, 2020)	Ex. 23-9 (DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-6	DOE Order No. 202-20-2 (Sep. 6, 2020)	DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

No.	Exhibit Name	Document Name	URL
23-7	DOE Order No. 202-21-1 (Feb. 14, 2021)	DOE Order No. 202-21-1 (Feb. 14, 2021) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-8	DOE Order No. 202-21-2	DOE Order No. 202-21-2) (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-9	DOE Order No. 202-22-1	DOE Order No. 202-22-1 (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-10	DOE Order No. 202-22-2	Exs. 23-13 and 23-14 (DOE Order Nos. 202-22-1 & 2 and amendments) (same)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-11	DOE Order No. 202-22-3 (Dec. 23, 2022)	DOE Order No. 202-22-3 (Dec. 23, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-12	DOE Order No. 202-22-4 (Dec. 24, 2022)	DOE Order No. 202-22-4 (Dec. 24, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-13	DOE Order No. 202-24-1 (Oct. 9, 2024)	Ex. 23-20 (DOE Order No. 202-24-1 (Oct. 9, 2024)) (Hurricane Milton)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

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23-14	DOE Order No. 202-05-3 (Dec. 20, 2005)	DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant, DC)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-15	DOE Order No. 202-17-1	DOE Order No. 202-17-1 (GRDA)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-16	DOE Order No. 202-17-2	DOE Order No. 202-17-2 (Yorktown Power Station)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-17	DOE Order No. 202-17-4 (Sept. 14, 2017)	DOE Order No. 202-17-4 (Sept. 14, 2017) (Yorktown Power Station – extension)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
24	Grand River Dam Authority Request for Emergency Order	Daniel S. Sullivan, Grand River Dam Authority, *Re: Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (April 11, 2017)	https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf
25	Wagner Order No. 202-25-6	U.S. Dep't of Energy, Order No. 202-25-6 (Jul 28, 2025)	

No.	Exhibit Name	Document Name	URL
26	Puerto Rico Electric Power Authority, Order No. 202-25-1	U.S. Dep't of Energy, Order No. 202-25-1 (May 16, 2025)	
27	Campbell Order	U.S. Dep't of Energy, Order No. 202-25-3 (May 23, 2025)	https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf https://perma.cc/Q7P7-TDTX
28	Eddystone Order	U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025)	https://perma.cc/PS3M-6CJA
29	Trump Admin Ordered Coal Plan Stay Open	Ella Nilsen, CNN, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill* (June 6, 2025)	https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright
30	CMS Energy Quarterly Report	U.S. Securities and Exchange Commission, Form 10-Q, *Quarterly Report for CMS Energy Corp.* (Jul. 31, 2025)	https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm

No.	Exhibit Name	Document Name	URL
31	Trump Administration Forcing Coal Plants to Stay Open	NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025)	https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first
32	U.S. Dep't of Energy Fact Sheet	U.S. Dep't of Energy, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025)	https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T]
33	Press Release Dep't of Energy U.S. Grid Report	Press Release, U.S. Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6]
34	Campbell Rehearing Order	U.S. Dep't of Energy, Order No. 202-25-3B, Order Addressing Arguments Raised on Rehearing (Sep. 8, 2025	

No.	Exhibit Name	Document Name	URL
35	August 6, 2025 State Request for Rehearing	Before the U.S. Dep't of Energy, In Re: Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, July 2025, Motion to Intervene and Protective Request for Rehearing (Aug. 6, 2025)	
35-1	August 6 Rehearing Request Exhibit A	North American Electric Reliability Corp (NERC) *Interregional Transfer Capability Study (ITCS)*, Final Report, Nov. 2024	
35-2	August 6 Rehearing Request Exhibit B	GridLab Analysis: Department of Energy Resource Adequacy Report (July 15, 2025)	
35-3	August 6 Rehearing Request Exhibit C	New York University School of Law, Institute for Policy Integrity, *Enough Energy A Rieview of DOE's Resource Adequacy Metholdology* (July 2025)	

No.	Exhibit Name	Document Name	URL
35-4	August 6 Rehearing Request Exhibit D	Nicholas Institute for Energy, Environment & Sustainability, *Rethinking Load Growth* (2025)	
35-5	August 6 Rehearing Request Exhibit E	London Economics Internat'l, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* (Jul 7, 2025)	
35-6	August 6 Rehearing Request Exhibit F	Grid Strategies, *Resource Adequacy Value of Interregional Transmission* (Jun. 2025)	
36	Second Campbell Order	U.S. Dep't of Energy, Order No. 202-25-9 (Nov. 18, 2025)	
37	Schahfer Order	U.S. Dep't of Energy, Order No. 202-25-12 (Dec. 23, 2025)	
38	Culley Order	U.S. Dep't of Energy, Order No. 202-25-13 (Dec. 23, 2025)	

No.	Exhibit Name	Document Name	URL
39	PJM Manual	Capacity Market & Demand Response Operations, *PJM Manuel 18: PJM Capacity Market* (Effective Date: Jul. 23, 2025)	
40	Eddystone Request for Rehearing	Before the U.S. Dep't of Energy, Order No. 202-25-4, Motion to Intervene and Request for Rehearing	
41	Moriyasu Declaration	Declaration of Callahan Moriyasu in Support of Request for Rehearing by State of Washington	
41-1	Historic Trends in Energy Use	Northwest Power and Conservation Council, *Historic Trends in Energy Use*	
41-2	Northwest Heat Wave	U.S. Energy Information Administration, *Northwest heat wave leads to record levels of summer electricity demand* (Aug. 23, 2017)	

No.	Exhibit Name	Document Name	URL
41-3	Ancillary Services Definitions and Capability Study	GE Energy Consulting, Ancillary Services Definitions and Capability Study (Dec. 2012)	
41-4	Optimizing Reserves	Electricity Advisory Committee, *Optimizing Reserves* (Oct. 2019)	
41-5	Historical Data	Bureau of Reclamation, Historical Data Access, Grand Coulee Dam (2020-2025)	https://www.usbr.gov/pn/hydromet/arcread.html
41-6	Washington Water Conditions	USGS Water Data for the Nation, *Washington Water Conditions* (Dec. 31, 2025)	
41-7	Water Management Data	U.S. Army Corps of Engineers, *Water Management Data* (Dec. 31, 2025)	
41-8	Grand Coulee Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Manage-ment Data, Grand Coulee Dam, Pacific Northwest Region, Dec. 2025	

No.	Exhibit Name	Document Name	URL
41-9	Chief Joseph Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Chief Joseph Dam, Pacific Northwest Region, Dec. 2025	
41-10	Lower Granite Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Lower Granite Lock and Dam, Walla Walla District, Dec. 2025	
41-11	Little Goose Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Little Goose Lock and Dam, Walla Walla District, Dec. 2025	
41-12	Lower Monumental Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Lower Monumental Lock and Dam, Walla Walla District, Dec. 2025	
41-13	Ice Harbor Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Ice Harbor Lock and Dam, Walla Walla District, Dec. 2025	

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41-14	McNary Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, McNary Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-15	John Day Lock and Dam Levels Dec 2025	U.S. Army Corps of Engineers, Water Management Data, John Day Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-16	The Dalles Lock and Dam Levels Dec 2025	U.S. Army Corps of Engineers, Water Management Data, The Dalles Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-17	Bonneville Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Bonneville Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-18	Priest Rapids Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Priest Rapids Dam, Pacific Northwest Region, Dec. 2025	

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41-19	Wanapum Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Wanapum Dam, Pacific Northwest Region, Dec. 2025	
41-20	Rock Island Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Rock Island Dam, Pacific Northwest Region, Dec. 2025	
41-21	NOAA NWS Three Month Outlook	NOAA, Nat'l Weather Service, *Three-Month Outlooks*, Official Forecasts Jan-Feb-Mar 2026	
41-22	Centralia Coal PPA (R)	Puget Sound Energy, Docket UE-250747, Attachment B (Impact of portfolio updates), *Sheet "Centralia Coal PPA(R)"* (Oct. 1, 2025)	
41-23	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025-2030	

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42	Press Release Re: Executive Order	U.S. Dep't of Energy, *Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter* (Dec. 17, 2025)	
43	Promises Made Promises Kept	U.S. Dep't of Energy, *Promises Made, Promises Kept, Unleashing the Golden Era of Energy Dominance and Lowering Prices* (Dec. 18, 2025)	
44	Executive Order 14156	Administration of Donald J. Trump, 2025, Executive Order 14156- Declaring a National Energy Emergency (Jan. 20, 2025)	
45	E2 Clean Economy Works: Nov. 2025 Analysis	Michael Timberlake, E2 Economy + Environment, Clean Economy Works: November 2025 Analysis (Dec. 12, 2025)	

No.	Exhibit Name	Document Name	URL
46	Energy Department Announces Termination of 223 Projects	U.S. Dep't of Energy, *Energy Department Announces Termination of 223 Projects, Saving Over $7.5 Billion* (Oct. 2, 2025)	
47	Archive of Energy Reliability and Resilience	U.S. Dep't of Energy, Office of Energy Efficiency & Renewable Energy, *Energy Reliability and Resilience*	
48	Dep't of Energy Response to State Rehearing Request of August 6	U.S. Dep't of Energy, *Re: August 6, 2025 Submission* (Sep. 5, 2025)	
49	Gomez Declaration	Declaration of David C. Gomez in Support of Request for Rehearing by State of Washington	
49-1	Centralia Power Plant Profile	S&P Capital IQ, Centralia Power Plant Profile	
49-2	Centralia Power Plant Financials	S&P Capital IQ, Centralia Power Plant Financials	

No.	Exhibit Name	Document Name	URL
50	Reeves Declaration	Declaration of Andrew Reeves in Support of Request for Rehearing by State of Washington	
50-1	Puget Sound Energy 2023 Electric Progress Report	Puget Sound Energy, *2023 Electric Progress Report*, Chapters 1-9 (2023)	
50-2	2025 Avista Electric Integrated Resource Plan	Avista, *Electric Integrated Resource Plan* (2025)	
50-3	Puget Sound Energy 2021 Integrated Resource Plan	Puget Sound Energy, *2021 PSE Integrated Resource Plan,* Chapters 1-9 (Apr. 2021)	
50-4	Letter Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting* (Dec. 31, 2025)	

No.	Exhibit Name	Document Name	URL
50-5	Jan 2024 Month In Review	Nat'l Weather Service, Pendleton OR, *The Month In Review, January 2024*	
50-6	WRAP Assessment of January 2024	WRAP, *Assessment of January 2024 Cold Weather Event*	
50-7	Reliability Coordinator Procedure, No. RC-410	California ISO, RC West, Reliability Coordinator Procedure, RC0410 (May 1, 2025)	
50-8	Western Energy Imbalance Market (WEIM)	Western Energy Markets	https://www.westernenergymarkets.com/western-energy-imbalance-market-weim
50-9	CAISO WEIM Fact Sheet	California Independent System Operator (CAISO) Fact Sheet, *Western Energy Imbalance Market* (WEIM)	https://www.caiso.com/Documents/western-energy-imbalance-market-fact-sheet.pdf
50-10	Pennington WRAP Area Map	David Pennington, WPP, Western Resource Adequacy Program (WRAP) Area Map (last modified Oct. 31, 2025)	https://www.westernpowerpool.org/news/wrap-area-map

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50-11	Avista Investor Overview	Avista, *Better energy for life*, Investor overview	https://investor.avistacorp.com/
50-12	RC West California ISO	California ISO, RC West	https://www.caiso.com/market-operations/products-services/rc-west
51	Nightingale Declaration	Declaration of Joel Nightingale in Support of Request for Rehearing by State of Washington	
52	Middleton Declaration	Declaration of Thomas Middleton in Support of Request for Rehearing by State of Washington	
52-1	Model Toxics Control Act	Washington Dep't of Ecology, Model Toxics Control Act	https://ecology.wa.gov/spills-cleanup/contamination-cleanup/rules-directing-our-cleanup-work/model-toxics-control-act (Last visited January 5, 2026)
52-2	TransAlta Agreed Order	Washington Dep't of Ecology, Agreed Order No. DE 24235 with TransAlta Centralia Generation LLC for TransAlta Centralia (Dec. 29, 2025)	

No.	Exhibit Name	Document Name	URL
52-3	Quick Facts Centralia WA	U.S. Census Bureau, Quick Facts Centralia (last visited Jan. 8, 2026)	https://www.census.gov/quickfacts/fact/table/centraliacitywashington/RTN131222
52-4	Data USA	Data USA, Centralia WA, Metropolitan Statistical Area (last visited Jan. 8, 2026)	https://datausa.io/profile/geo/centralia-wa-31000US16500
52-5	Emissions of Hazardous Air Pollutants	Environmental Health & Engineering, Inc. *Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants* (Mar. 7, 2011)	
53	Rybarik Declaration	Declaration of Brian Rybarik in Support of Request for Rehearing by State of Washington	
54	FEMA Declaration of Emergency	U.S. Dep't of Homeland Security, FEMA, *Emergency Declaration*, FEMA-3629-EM (Dec. 9, 2025)	

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55	Best Practices Resource Planning	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024, Revised Dec. 2024)	https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf https://perma.cc/D68F-WHWQ
56	Trump Signs Executive Orders	New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025)	
57	Declared National Energencies	Brennan Center for Justice, Declared National Emergencies under the National Emergencies Act	https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act
58	Campbell Order No. 202-25-7	Dep't of Energy Order No. 202-25-7 (Aug 20, 2025)	
59	Eddystone Order No. 202-25-8	Dep't of Energy Order No. 202-25-8 (Aug. 27, 2025)	

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60	Trump Order Keep Michigan Power Plant Open	Tom Perkins, *Trump Order to Keep Michigan Power Plan Open Costs Taxpayers $113m* (Nov. 28, 2025)	https://www.theguardian.com/us-news/2025/nov/28/trump-michigan-power-plant
61	Short-Term Energy Outlook Browser	U.S. Energy Information Administration, Short-Term Energy Outlook Data Brower (Dec. 9, 2025)	https://www.eia.gov/outlooks/steo/data/browser
62	U.S. Frackers and Saudi Officials Tell Trump They Won't Drill More	Wall Street Journal, *U.S. Frackers and Saudi Officials Tell Trump They Won't Drill More* (Feb. 3, 2025)U.	at https://www.wsj.com/business/energy-oil/trump-oil-drilling-saudi-arabia-71c095ff?reflink=desktopwebshare_permalink
63	Eddystone Order No. 202-25-10	Dep't of Energy Order No. 202-25-10 (Nov. 25, 2025)	
64	Winter Outlook 2025-2026	US Dep't Commerce, Nat'l Oceanic and Atmospheric Admin., Nat'l Weather Service, *Winter Outlook 2025-2026*, at 4 (Last visited Jan. 6, 2025)	https://www.weather.gov/media/abr/sitreport/2025-2026WinterOutlook.pdf

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65	TransAlta Signs Agreement	*TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion*, TransAlta (Dec. 31, 2025, 9:39 AM)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.
66	TransAlta Conversion	Jacob Moore, @chronline.com, *Announcement comes as company must take its coal-fired burner offline; 700 jobs expected at peak of construction, 40 to be employed permanently* (Dec. 10, 2025)	https://www.chronline.com/stories/transalta-centralia-to-transition-from-coal-to-natural-gas,392533
67	Best Practices Resource Planning (PDF Exhibit Parts 1-7)	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024)	https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf
68	Trump Vowed Make Coal King	Hanna Northey, EE News, *Trump has vowed to make coal king again. How's it going?* (Sep. 24, 2025)	https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

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69	Interior Approves Mining Plan	U.S. Dep't of the Interior, *Interior Approves Mining Plan to Unlock 14.5 Million Tons of Coal at Antelope Mine* (Wyoming) (Aug. 2025)	https://www.doi.gov/pressreleases/interior-approves-mining-plan-unlock-145-million-tons-coal-antelope-mine
70	Donors Benefit from Trump Return to Office	Karen Yourish, Kenneth Vogel, Charlie Smart, The New York Times, *Hundreds of Big Post-Election Donors Have Benefited from Trump's Return to Office* (Dec. 22, 2025)	https://www.nytimes.com/interactive/2025/12/22/us/politics/trump-donors-fundraising-benefits.html
71	White House Offers Concierge Service	Jake Spring, *White House offers 'concierge' service to fossil fuel firms, official says* (Updated Oct. 7, 2025)	https://www.washingtonpost.com/climate-environment/2025/10/07/white-house-fossil-fuel-concierge/
72	Trump Admin. Reconsiders Rule	Rachel Frazin, The Hill, *Trump admin will reconsider part of rule to protect miners from lung diseases* (Dec. 1, 2025)	https://thehill.com/policy/energy-environment/5628531-miner-lung-disease-rule-silica/

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73	Trump Wants Mining	Hannah Northey, EENews, T*rump wants mining. Federal mine safety workers are on the chopping block* (Sep. 5, 2025)	. https://www.eenews.net/articles/trump-wants-mining-federal-mine-safety-workers-are-on-the-chopping-block/
74	Grid Strategies Report	Michael Goggin, Grid Strategies LLC, The Cost of Federal Mandates to Retain Fossil-Burning Power Plants (Aug. 2025)	
75	Notice to Stakeholders	U.S. Dep't of Labor, Mine Safety and Health Admin., *Notice to Stakeholders*	https://www.msha.gov/notice-stakeholders
76	Columbia River Basin Dams	U.S. Army Corps of Engineers, NW Division Website, *Columbia River Dams* accessed Dec. 30, 2025)	https://www.nwd.usace.army.mil/crwm/cr-dams/
77	Hydropower Impact – Bonneville Power Admin.	Bonneville Power Administration, *Hydropower Impact; All About Federal Hydropower, the Largest Source of Clean Power in the U.S.* (Last accessed Dec. 30, 2025)	https://www.bpa.gov/energy-and-services/power/provider-of-choice/resources

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78	Hydropower Flows Here – Bonneville Power Admin.	Bonneville Power Administration, *Hydropower Flows Here* (Last accessed Dec. 30, 2025)	https://www.bpa.gov/learn-and-participate/community-education/hydropower-flows-here
79	BPA Maintains Strong Financial Position	Bonneville Power Administration, Newsroom, *BPA maintains strong financial position despite challenging water year* (Nov. 13, 2025)	https://www.bpa.gov/about/newsroom/news-articles/20251113-bpa-maintains-strong-financial-position-despite-challenging-water-year
80	Pacific Moisture Drenches the U.S. Northwest	NASA Earth Science, *Pacific Moisture Drenches the U.S. Northwest* (Dec. 12, 2025)	https://science.nasa.gov/earth/earth-observatory/pacific-moisture-drenches-the-u-s-northwest/
81	President Approves Washington Emergency Declaration	U.S. Dep't of Homeland Security, FEMA, *President Donald J. Trump Approves Emergency Declaration for State of Washington* (Dec. 12, 2025)	https://www.fema.gov/press-release/20251212/president-donald-j-trump-approves-emergency-declaration-state-washington

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82	Federal Teams Support State-Led Response to Washington Storms	U.S. Dep't of Homeland Security, FEMA, *Federal Teams Support State-Led Response to Historic Washington Severe Storms and Flooding* (Dec. 23, 2025)	https://www.fema.gov/blog/federal-teams-support-state-led-response-historic-washington-severe-storms-and-flooding
83	Stopping Radical Environ-mentalism to Generate Power	Presidential Actions, Presidential Memoranda, *Stopping Radical Environmentalism to Generate Power for the Columbia River Basin*, (Jun. 12, 2025)	https://www.whitehouse.gov/presidential-actions/2025/06/stopping-radical-environmentalism-to-generate-power-for-the-columbia-river-basin/ (last accessed January 5, 2026)
84	Electricity Data Browser	U.S. Energy Info. Admin., *Electricity Data Browser*, EIA (last visited Nov. 4, 2025)	https://www.eia.gov/electricity/data/browser/#/topic/7
85	Consumer Prices Up 2.9% August 2024 to August 2025	U.S. Bureau of Labor Statistics, *Consumer prices up 2.9 percent from August 2024 to August 2025*, TED: The Economics Daily (Sept. 17, 2024)	https://www.bls.gov/opub/ted/2025/consumer-prices-up-2-9-percent-from-august-2024-to-auCogust-2025.htm

No.	Exhibit Name	Document Name	URL
86	Report: Lack of Affordable Housing Options	Wash. State Dept. of Commerce, *Report: Lack of affordable housing options reaches critical levels in communities throughout Washington state* (May 13, 2024)	https://www.commerce.wa.gov/report-lack-of-affordable-housing-options-reaches-critical-levels-in-communities-throughout-washington-state/
87	Trends in Financial Hardship	United for Alice, *The State of Alice in Washington*, United Way of Northern New Jersey	https://www.unitedforalice.org/trends-in-hardship/Washington
88	Emission Performance Standard SB 1368	California Energy Commission, Emission Performance Standards – SB 1368	https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/emission-performance-standard-sb-1368
89	Coal and the Environment	U.S. Energy Information Administration, *Coal explained: Coal and the environment* (Last updated: Apr. 17, 2024)	https://www.eia.gov/energyexplained/coal/coal-and-the-environment.php
90	What They are Saying: President Trump Stops Radical Environ-mentalism	The White House Newsletter, *What They Are Saying: President Trump Stops Radical Environmentalism to Generate Power for the Columbia River Basin* (Jun. 13, 2025)	https://www.whitehouse.gov/articles/2025/06/what-they-are-saying-president-trump-stops-radical-environmentalism-to-generate-power-for-the-columbia-river-basin/

No.	Exhibit Name	Document Name	URL
91	Special Environmental Analysis of Balancing Authority of Northern California	U.S. Dep't of Energy, *Special Environmental Analysis of Balancing Authority of Northern California (BANC) Operations during 202(c) Emergency Order Operations between September 4, 2022, and September 8, 2022* (Apr. 19, 2024)	https://www.energy.gov/sites/default/files/2024-08/sea-07-banc-special-environmental-analysis-2024-04-19.pdf
92	SPP Balancing Authority Map	Southwest Power Pool (SPP) Balancing Authority Map	https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png
93	NCR11393 Compliance Audit	Gridforce Energy Management, LLC, Compliance Audit, NCR11393 (Dec. 20, 2019)	
94	Craig Order No. 202-25-14	U.S. Dep't of Energy, Order No. 202-25-14 (Dec. 30, 2025)	

No.	Exhibit Name	Document Name	URL
95	Research Power Corp. Order Authorizing Electricity Exports to Canada	U.S. Dep't of Energy, Grid Deployment Office, Research Power Corporation, GDO Docket No. EA-365-C, Order Authorizaing Electricity Exports to Canada	
96	PJM to Ratchet Down Projected AI Power Demand Eastern US	Peter Behr, Energywire, *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6, 2026)	
97	Declaration of Arne Olson	U.S. of America, Before the Dep't of Energy, Re: Transalta Centralia Generation, Declaration of Arne Olson (Jan. 13, 2026)	
97-1	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025-2030	

No.	Exhibit Name	Document Name	URL
98	Final Order Granting Petition	Washington Utilities and Transportation Commission, Re: Puget Sound Energy, Docket UE-121373, Order 03, Final Order Granting Petition, Subject to Conditions (Jan. 9, 2013)	
99	E3 Northwest Resource Adequacy Study Review	Sylvan Energy Analytics, GridLab, *Near-term winter resource adequacy challenges in the Pacific Northwest, A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges* January 2026	

EXHIBIT 135

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-18

MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, the State of Washington, by and through the Washington State Attorney General, Nicholas W. Brown, moves to intervene and for a stay, and requests that the Department of Energy ("DOE") grant rehearing of Order No. 202-26-18 (March 16, 2026) ("Centralia II"), attached hereto as Ex. 100. Centralia II extends for an additional 90 days Order No. 202-25-11 (as amended by 202-25-11B) ("Centralia I"). Because the legal and factual issues here directly overlap and repeat the same matters as related to Centralia I, Washington hereby incorporates by reference its petition for rehearing of Order No. 202-25-11, including all arguments, exhibits, and other reference materials, and reassert them herein as grounds for rehearing Centralia II.

I. INTRODUCTION

On December 16, 2025, DOE issued the Centralia I order to TransAlta Centralia Generation LLC directing that the Centralia Coal Plant ("TransAlta Centralia" or "Centralia") remain in operation as a coal facility. Centralia I was counterproductive to its own aims, failing to establish any actual emergency and threatening to derail the long-planned conversion of

Centralia into a modernized natural gas facility with greater capacity and more flexibility than the current aged coal facility. DOE now doubles down, issuing an order that is equally flawed.

DOE should immediately withdraw Centralia II. As with Centralia I, Centralia II is unlawful, internally inconsistent, misguided, and based on incorrect assertions about the Northwest's power infrastructure and operation. DOE again makes assertions of unfettered authority to usurp state and regional power planning based on generalized long-range concerns. This again violates the Federal Power Act, which expressly limits DOE's authority to *actual* emergency situations involving war or the sudden and unexpected loss of power.

An emergency did not exist in December and does not exist now. As a result, Centralia II again fails to present any legitimate factual basis—let alone substantial evidence—to support its claim that maintaining Centralia as a coal-fired facility is necessary to "meet" any emergency. And, as with Centralia I, Centralia II is detrimental to the public interest by undermining the very grid stability it purports to protect in a way that will be enormously detrimental to the Northwest's rate payers. Washington calls on DOE to rescind Centralia II and end these purely political stunts.

II. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

Washington incorporates its statement of issues and specifications of error from its petition for rehearing of Order No. 202-25-11. Washington submits the following additional statement of issues and specifications of error:

- Centralia II is arbitrary, capricious, and not based on substantial evidence because Centralia II relies on an expired North American Electric Reliability Corporation Winter Reliability Assessment.

- Centralia II is arbitrary, capricious, and not based on substantial evidence because, in justifying "emergency" conditions, it relies on a North American Electric

Reliability Corporation Long Term Resource Adequacy report that does not identify any present lack of energy resources in the Northwest, predicts normal energy needs in the Northwest for the next several years, and, even with regard to future energy needs, does not establish or predict emergency conditions.

- Centralia II is arbitrary, capricious, and not based on substantial evidence because it relies on a superseded district court injunction related to the Columbia River Power System and fails to account for—let alone even acknowledge—that the injunction has express provisions for dealing with emergency circumstances.

- Centralia II is arbitrary, capricious, and contrary to law because DOE's use and interpretation of section 202(c) to authorize emergency orders for hypothetical future needs, long-term energy planning, or other circumstances that were not unforeseen or imminent raises serious constitutional concerns and violates Washington's right to procedural due process. *See Jennings v. Rodriguez*, 583 U.S. 281, 296 (2018); *Mathews v. Eldridge*, 424 U.S. 319, 333 (1976).

III. MOTION TO INTERVENE AND INTERVENOR'S INTEREST

The State of Washington moves to intervene in this proceeding and become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. *See* RCW 43.10.030(1). *See also City of Seattle v. McKenna*, 172 Wash. 2d 551, 259 P.3d 1087 (2011) (noting that RCW 43.10.030(1) grants the Attorney General discretionary authority to act in any forum "on a matter of public concern" (internal quotations and citations omitted). The TransAlta Centralia Plant is located in the State of Washington, and the State is aggrieved by the Order in several ways.

First, Washington has a direct contractual interest in the retirement of Centralia on December 31, 2025. In 2011, the Washington Legislature passed the Coal-Fired Electric Generation Facilities Bill, SB 5769. S.B. 5769, 62nd Leg., (Wash. 2011). That Act directed Centralia to comply with the state's greenhouse gas emission performance standards by the end of 2020 for its first boiler and the end of 2025 for the second. RCW 80.80.040(c). It also directed the Governor to enter into a Memorandum of Agreement with the owners of

Centralia. RCW 80.80.100. The State and TransAlta signed the Memorandum of Agreement in 2011, which was amended in 2017 to specify that Centralia could continue to generate power, so long as it was not coal-fired power. Ex. 5 (2011 MOA); Ex. 6 at section 1 (amending Subsection D(5) of the MOA) (2017 MOA Amendment).

The Memorandum of Agreement required Centralia to permanently cease coal power generation from one boiler in 2020, and the other boiler in 2025. Ex. 5; Ex. 6. In exchange for that commitment, the State of Washington confirmed that the facility met the greenhouse gas emissions performance standards and other environmental requirements of the State, guaranteed the ability of TransAlta to enter into long-term power contracts for the sale of electricity from Centralia, and promised to maintain sales and use tax exemptions for the plant. Ex. 5. The State of Washington kept those promises, sacrificing tax revenue and granting TransAlta flexibility with regard to operational controls in exchange for Centralia ceasing coal operations by the end of 2025. *See, e.g.*, RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax); RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and remediation costs in rates).[1] Because the Order deprives Washington of the benefit of its bargain under the Memorandum of Agreement, Washington suffers distinct harms as a result of the Order.

[1] *See e.g.* RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax); RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and remediation costs in rates).

Second, Washington has a direct regulatory interest in Centralia's retirement by the end of 2025 because continued coal-fired operations will directly violate state law as well as a regulatory order issued by the Department of Ecology. Centralia is subject to Washington's emissions performance standard (EPS) for baseload electric generation in the state, RCW 80.80.040. The EPS is essentially a carbon intensity standard, limiting the volume of greenhouse gas emissions that an electric generating facility may emit per megawatt-hour of power produced. RCW 80.80.040(1), (3). This standard cannot generally be met by coal-fired plants without employing carbon sequestration technology.[2] The application of this standard was delayed for TransAlta until the scheduled shutdown of its two boilers at the end of 2020 and 2025. RCW 80.80.040(3)(c) ("A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025: [referencing process for setting standard].").

TransAlta relied on the 2025 retirement of its last coal-fired boiler as its means of complying with Washington's emissions performance standard. Ex. 7 at 2, §D(a)(1) (2011 BART Order) ("The plant owner, the Governor's office, and environmental organizations

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[2] The emission performance standard is currently set at 876 GHG/MWh. WAC 173-407-130 (setting forth EPS standard in Ecology's EPS rules). *See* RCW 80.80.040(1)(providing procedures for setting standard); RCW 80.80.050 (setting out Washington Department of Commerce's role to set standard); WAC 194-26-020 (Washington Department of Commerce setting standard).

anticipate that compliance with this requirement will be accomplished by decommissioning the [coal-fired] units."). Further, the Washington Department of Ecology issued Centralia a regulatory order imposing Best Available Retrofit Technology ("BART") requirements pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART order specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition; Ex. 8 at 3, condition 3 (2020 BART Order, Revision 2). Thus, continued operations of TransAlta's coal-fired boilers, without substantial investment in new emissions-lowering technology, will directly violate Washington's Emission Performance Standard and BART order.

Third, Washington residents will suffer health and environmental harms because of Centralia II, with costs to the State resulting from the heightened burden on state-provided insurance and public hospitals. As detailed below in Section IV(H)(2), continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonians' health imposing direct harms on the State and its agencies, and impair visibility at Washington's iconic natural areas such as the Mount Rainer National Park. Ex. 10 at ¶ 7 (Declaration of Gary Palcisko).

Fourth, these environmental harms will frustrate the Washington State's regulatory interests, harm the State's public trust resources, and pose a financial burden to the State. For example, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12 (Top 10 Stationary Sources of GHG Emissions in WA, 2022); Ex. 13 (Top Washington Greenhouse Gas Emissions Sources, 2023). By mandating the continued operation of the

Centralia Coal Plant, Centralia II will make it harder for Washington to meet its statutory greenhouse gas emissions reduction requirements. RCW 70A.45.020. And continued burning of coal will also hinder Washington's investigation and cleanup of the site under the Model Toxics Control Act (MTCA). *See* Ex. 52 at ¶ 16 (Declaration of Thomas Middleton). Under MTCA, the Washington Department of Ecology is responsible for investigating contamination, developing cleanup action plans, and identifying potentially liable parties (PLPs) for sites contaminated with hazardous substances. *Id.* at ¶ 4-14.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above MTCA cleanup levels. *Id.* at ¶ 7. Centralia II will prolong the contamination of the Site, exacerbating the time and resources the State must expend to investigate and plan its cleanup. *Id.* at ¶ 14. Centralia II will also cause continued aerial emissions of hazardous substances, which have the potential to settle on and contaminate thousands of properties and create thousands of potentially liable parties under MTCA. *Id.* at ¶ 14. Determining liability and cleanup responsibility for so many sites is resource-intensive for the State. *Id.* Finally, the Centralia Coal Plant uses settling ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15. Centralia II will require TransAlta to continue using the settling ponds, preventing the Washington Department of Ecology from performing cleanup of the ponds, and potentially posing risks related to groundwater contamination. *Id.*

Fifth, Washington's electricity grid will be less reliable because of Centralia II. In addition to the direct interest in grid reliability to power state buildings, public schools, and

hospitals, Washington has a regulatory interest in maintaining grid reliability.[3] Centralia experiences extended periods of non-operation. In the years 2023-2025, the Centralia Plant Unit #2 shut down 29 times, 25 of which were forced outages. Ex. 11 at ¶ 7 (Declaration of Clinton Lamoreaux). Additionally, when coal-powered generation facilities do shut down, they have a longer start-up time than natural-gas-powered facilities, which makes them less responsive to fluctuating energy demands. Ex. 14 (Owen Comstock, *About 25% of U.S. power plants can start up within an hour,* U.S. ENERGY INFO. ADMIN., November 19, 2020). This is especially true for "cold" startups, where the facility must start up after an extended period of nonactivity. Cold startups take longer than startups following a briefer outage where the facility components are still warm from recent operation. Ex. 11 at ¶ 8. It took Centralia anywhere from 11 to 18 hours to reach its operational capacity during the six cold startups from the fourth quarter of 2024 through the third quarter of 2025. *Id.* Plus, because Centralia is likely overdue for maintenance, it could face more frequent shutdowns than in previous years. Ex. 11 at ¶ 10-11.

This will be exacerbated by the apparent staffing shortages Centralia faces. Ex. 11 at ¶ 12. Finally, aside from in limited circumstances, Washington utilities are prohibited from purchasing power from coal plants after December 31, 2025. RCW 19.405.030. Because of these frequent shutdowns, the length of time needed to start up the plant, the uncertainties

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[3] The Washington Utilities and Transportation Commission (UTC) is tasked with regulating IOUs such that any services rendered are "adequate and efficient," RCW 80.28.010(2), (11); RCW 19.405.080(2)(a) (reporting requirements concerning reporting on meeting load, reliability standards, and resource adequacy); RCW 80.28.130 (granting UTC authority to order an electric utility to make improvements to their system to "secure adequate service or facilities").

around maintenance and staffing, and the legal barriers to purchasing power from Centralia, coal operations at Centralia are less reliable, efficient, or economical than other alternatives. However, Centralia II will force ratepayers to pay for Centralia's operations rather than investing in alternatives, resulting in a loss of capacity and flexibility for Washington's electricity grid.

Sixth, Washington agencies, households, and businesses will likely pay higher electricity bills because of Centralia II, and Washington has a regulatory interest in keeping electricity rates fair and affordable.[4] Under the most recent Power Purchase Agreement (PPA) which expired on December 31, 2025, the price from Centralia's coal is significantly higher than the wholesale energy market price, at $62.04 per MWh versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15 (Declaration of Callahan Moriyasu). It is also unclear whether Centralia will be safe to operate. Recent inspections and the most recent quarterly report indicate that Centralia's pollution control technology requires maintenance or repairs. Ex. 11 at ¶ 10-11. Further, recent staffing shortages may have led to the violations that Centralia was noticed for in December. Ex. 11 at ¶ 12. TransAlta will likely have to expend resources to quickly hire and train new staff to operate the facility. TransAlta will no doubt seek to recover those costs through its rates. Although the precise amount of the costs is not yet known, by ordering the continued operation of TransAlta's Centralia Coal Plant, Centralia II ensures that Washington ratepayers will see unreasonably higher electricity bills, in

[4] *See e.g.* RCW 80.28.010(1) (The UTC is also tasked with regulating IOUs in the public interest and ensuring rates for "any service rendered" are "just, fair, reasonable, and sufficient."); The Clean Energy Transformation Act requires utilities to achieve targets at the "lowest reasonable cost," RCW 19.405.040(6)(a)(i), -.050(3)(a),-.060(1)(c)(ii), -.080(2)(b).

contradiction with Washington's statutory mandate to secure rates that are "just, fair, reasonable, and sufficient." RCW 80.28.010(1).

IV. BACKGROUND

A. The Long-Planned Retirement of TransAlta's Coal-fired Units

1. The TransAlta Centralia coal-fired power plant

The Centralia generating plant is a coal-fired power plant located just east of Centralia in Lewis County, Washington that is owned and operated by TransAlta Generating LLC ("TransAlta Centralia" or "Centralia"). Centralia was built in the late 1960s and originally consisted of two coal-fired boilers. Ex. 15 (The Daily Chronicle, *Plant Job Underway*, June 14, 1968); Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). The first boiler went into operation in 1971 and the second in 1972. The first boiler, known as "Unit 1" was retired in 2020, and the second boiler, "Unit 2," was scheduled to retire by December 31, 2025. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). Centralia currently has a nameplate generating capacity of 729.9 MS and a net capacity of 670 MW. Ex. 18 at "Operating" tab, row 5359, plant name "TransAlta Centralia Gen LLC" (U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860).

TransAlta Centralia generates electricity by combusting pulverized coal in a boiler to generate pressurized steam to drive a turbine. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). This produces emissions of sulfur dioxide (SO2), oxides of nitrogen (NOx), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants including mercury. Ex. 17 at 2. TransAlta Centralia has been

one the largest historical sources of NOx and SO_2 in Washington, annually emitting over 5,000 tons of NOx and 1,500 tons of SO2 in 2011–18. Ex. 19 at 74 (2022 Visibility SIP). Since closure of Unit 1 of Centralia in 2020, emissions have decreased by approximately half, but these emissions still rank amongst the highest in the State for a single source. Ex. 19 at 74. TransAlta Centralia is also the largest single stationary source of greenhouse gas emissions in the state with, over 3.9 million metric tons of annual CO2 emissions in 2022, and over 4.5 MMT CO2 in 2023. Ex. 12; Ex. 13. These pollutants have significant adverse health and environmental impacts. Ex. 10 at ¶¶ 7–14. TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural areas, including at Mount Rainer National Park, located only 50 miles from the plant. Ex. 19 at 172 (2021 Visibility SIP).

2. Agreement reached over a decade ago to transition TransAlta away from coal

In 2011, Washington, TransAlta, environmental groups, and the local community worked together to establish a plan to transition Centralia away from coal towards cleaner fuels. Ex 20 (TransAlta Power Plant, Department of Ecology). The Washington Legislature passed the Coal-Fired Electric Generation Facilities Act, Engrossed Second Substitute S.B. 5769, Ch. 180, Wash. Laws of 2011, requiring TransAlta Centralia to comply with the state's greenhouse gas emission performance standards beginning at the end of 2020 for Unit 1 and the end of 2025 for Unit 2. Ch. 180, Wash. Laws of 2011 § 103; RCW 80.80.040(1), (3)(c). The Washington Department of Ecology then issued a Best Available Retrofit Technology (BART) order to TransAlta pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART

Order recognized that TransAlta Centralia would comply with the greenhouse gas emissions standards through the phased retirement of its coal-fired boilers. Ex. 7 at 2 §D(a). The BART order further specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition 4; Ex. 8 at 3, condition 3. By the end of 2011, the State and TransAlta signed a Memorandum of Agreement, as required by SB 5769, in which TransAlta formally agreed to the phased shutdown of both coal-fired boilers by the end of 2020 and 2025 respectively. Ex. 5 at 1 (Recital D) (TransAlta agreed to "permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025.").

In 2017, the MOA was amended to, among other things, change the scope of power generation activities that TransAlta Centralia was required to cease in 2020 and 2025. While the 2011 MOA originally requiring cessation of all "power generation operations" in the two boilers, the amendment signed in 2017 narrowed this to requiring cessation of only "*coal-fired* power generation operations" of each boiler. Ex. 6 at Section 1 (amending Subsection D(5) of the MOA). This would allow TransAlta to continue generating electricity at Centralia upon the conversion of its boilers to cleaner fuels such as natural gas. Ecology's 2020 revision to TransAlta's BART Order reflected this, acknowledging the possibility of continued operation of the Centralia plant with cleaner fuels. Ex. 9 at 3 (2020 Bart Order TSD at 3) ("If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.").

3. TransAlta coal-to-gas conversion project

TransAlta has now developed a plan to convert TransAlta Centralia to natural gas.[5] On December 9, 2025, TransAlta announced a long-term agreement with Puget Sound Energy to perform a coal-to-gas conversion on Centralia's Unit 2 facility with a planned contracted capacity of 700 MW to deliver power to Puget Sound Energy ("PSE") through 2044. Ex. 20 at 1 (Press Release from TransAlta dated Dec 9, 2025,). TransAlta expects to invest approximately $600 million in capital expenditures in the project, and is targeting late-2028 to begin commercial operations, which will reduce emissions by approximately 50%. *Id*. TransAlta's President and Chief Executive Officer, John Kousinioris explained that TransAlta was "pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers." *Id*.

After conversion, TransAlta Centralia will operate only when there is high demand, with the majority of its hours of operation expected to be at half load (~350 MW) or at minimum stable generation load (~190 MW), but with the ability to quickly ramp up to high loads when needed by the grid. Ex. 21 at 1-1 (December 2025 TransAlta PSD Permit application). Conversion of Centralia to natural gas will dramatically reduce TransAlta Centralia's emissions of almost all pollutants, including large and fine particulate matter,

[5] The State cites to the announced conversion to natural gas in keeping with industry practice of including announced planned additions to generation. To finalize those plans, TransAlta will need numerous permits and approvals from the State for the conversion to occur. Nothing within this filing should be interpreted as any agency or arm of the State presupposing or otherwise commenting on the merits of those permits or approvals.

nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), lead, and carbon dioxide (CO_2). Ex. 21 at 3–4 (Table 3-1).

B. Washington Recently Assessed and Confirmed Resource Adequacy in Our Region

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Indeed, in its July 2025 resource adequacy report, DOE wrote, "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level….entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience." Ex. 4 at i (DOE 2025 Resource Adequacy Report).

In this, DOE is correct, and Washington's Utilities and Transportation Commission does precisely that, and held three meetings in 2025 in conjunction with Washington's Department of Commerce to consider information from industry experts from Washington utilities, regional planning organizations, transmission operators, reliability experts, and the public. Ex. 53 ¶¶ 4-6 (Declaration of Brian Rybarik, Chair of the Washington Utilities and Transportation Commission). As a matter of best practice, resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country. *See* Ex. 55 (*Best Practices in Integrated Resource Planning,* Synapse Energy Economics & Lawrence Berkeley National Laboratory (Nov. 2024). Following this best practice, the Washington Utilities and Transportation Commission, and the November 2025 Winter Readiness Resource Adequacy meeting, Washington planners invited presentations from National Electric

Reliability Corporation (NERC), the Western Electricity Coordinating Council, Arne Olson, the author of the E3 PowerPoint, as well as from Washington utilities. Ex. 22 (Nov. 19, 2025 Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting) (The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

By contrast, DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. And, as far as Washington can determine, DOE failed to attempt consultation with any of the local, regional, or national reliability experts in issuing its emergency order regarding TransAlta. Using the information from the entities responsible for maintenance and operation of the grid, in November 2025, Washington's utility regulators confirmed the adequacy of generation resources for our state's electricity grid. Ex. 22. In a letter summarizing the September meeting, Washington state utility regulators assessed resource adequacy as follows:

> Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.
>
> However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect

> capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

Ex. 22 at 1–2. Washington's utility planners also considered Washington's winter readiness, reporting that:

> Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Counsel, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions with winter. Extreme weather poses and elevate risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures for firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.
>
> At the November 4 Meeting, the Bonneville Power Administration and utilities shared steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sount Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

Ex. 50, ¶ 10 (Declaration of Andrew Reeves); Ex. 50-4 (Summary of 2025 Winter Preparedness Meeting). The Chair of the Washington Utilities and Transportation Commission reviewed DOE's emergency order in light of his industry experience, his review of resource adequacy plans filed with the Commission, the information from national, and regional experts and concluded, "I do not find that DOE's Order's conclusions that an energy emergency exists in the coming winter months credible, nor do I agree that action under the DOE order (keeping the Centralia coal plant available) will assist in solving the unlikely extreme conditions that could lead to an energy emergency." Ex. 96 at 3.

Tellingly, DOE's flawed July 2025 Resource Adequacy Report found that even assuming all firm planned retirements, including TransAlta, and assuming minimal resource additions the Washington region faces no significant long term reliability risk:

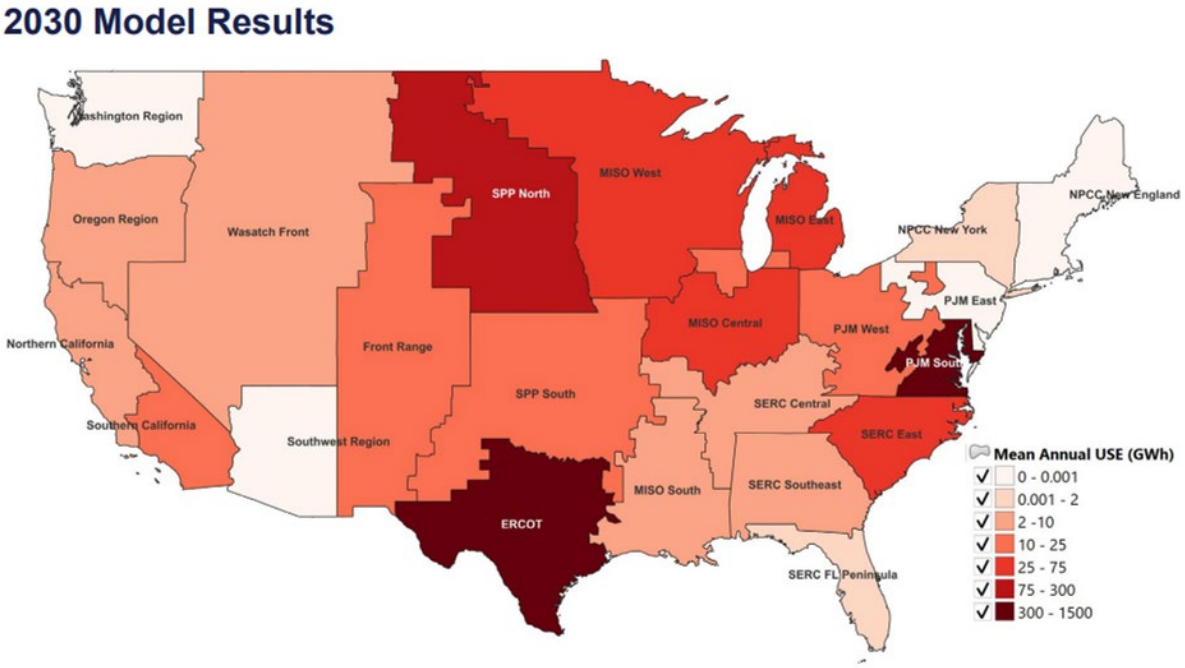


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Ex. 4 at 6 (DOE 2025 Resource Adequacy Report). The deep methodological flaws in DOE's report are discussed at greater length below. But for the purposes of this review, all information agrees; even under DOE's worst case scenario analysis, the Washington region is one of the few regions in the country in which reliability is not a concern before 2030. The reality is that there is no reasonable dispute that there is no energy emergency in the Washington to justify an order to keep TransAlta available as a coal plant.

C. DOE's Historical Use of Section 202(c)

Prior to 2025, DOE has used section 202(c) sparingly, and only in response to concrete, particularized emergencies subject to limitations to ensure that DOE's reach extends no further than necessary to address the emergency at hand.

As discussed below, section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). The law also effectively immunizes noncompliance with "any Federal, State, or local environmental law or regulation" associated with an action or omission necessary to comply with a 202(c) order." 16 U.S.C. § 824a(c)(3). However, the Act also imposes significant limits on any 202(c) order that "may result in a conflict" with a pollution control requirement, including limiting the hours of operation of such facilities and limiting the order to 90-days, with extension possible. 16 U.S.C. § 824a(c)(2) and (4).

That authority originated as a wartime power granted in 1935 to what was then the Federal Power Commission in order to guard against energy-related shortages that were viewed as hampering national security during World War I. *See* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 798-802 (2025). The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II. *See id.* at 803. Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. These "interconnection" orders between utilities were more necessary at a time when

America's electric grid was more fragmented, monopolized, and less diversified than it is today. *Id.* at 802-804. Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time. *Id.* at 801-802. A number of organizational changes ensued in the decades following the War and the provision's authority eventually came to rest with the Secretary of Energy. *Id.* at 803-04; 42 U.S.C. § 7151(b).

DOE has historically invoked its 202(c) emergency sparingly to respond to clear-cut and imminent emergencies to avoid immediate significant blackouts. *See* Rolsma, *supra*, at 805-509. Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of 2024, DOE appears to have used section 202(c) twenty times, not counting amendments and extension orders, prior to 2025. *See* Ex. 23-1 through 23-20. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000. Ex. 23-1 (DOE, *Order Pursuant to Section 202(c) of the Federal Power Act*, December 14, 2000). Since then, by far the most common usage—comprising 14 of 20 instances—has been in response to extreme weather events such as hurricanes, extreme cold, and extreme heat. *See* Exs. 23-2 and 23-3 (DOE Order Nos. 202-05-1 & -2, September 28, 2005) (response to Hurricane Rita); Ex. 23-4 (DOE Order No. 202-08-1, September 14, 2008) (Hurricane Ike); Ex. 23-5 (DOE Order No. 202-20-1, August 27, 2020) (Hurricane Laura); Ex. 23-13(DOE Order No. 202-24-1, October 9, 2024) (Hurricane Milton); *See* Ex. 23-7 (DOE Order No. 202-21-1, February 14, 2021) (extreme cold); Ex. 23-11 (DOE Order No. 202-22-3 (December 23, 2022) (extreme cold); Ex. 23-12 (DOE Order No. 202-22-4, December 24, 2022) (extreme cold); Ex. 23-6 (DOE Order No. 202-20-2, September 6, 2020) (extreme heat in California);

Ex. 23-8 (DOE Order No. 202-21-2, September 10, 2021) (extreme heat, wildfires and drought in California); Exs. 23-9, 23-10 (DOE Order Nos. 202-22-1 & 2, September 2022) (same).

In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both. And, in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements. DOE also limited the duration of those orders to the minimum period necessary to address the emergency, typically lasting for a period of days to weeks. *See* Rolsma, at 839-42 tbl.1 (chronicling all section 202(c) orders issued "after dissolution of the Federal Power Commission").

The typical process for issuing a section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes including demand response mechanisms are incapable of addressing, though they may be issued by DOE unprompted as well. *See* 10 C.F.R. § 205.370. Applications for section 202(c) orders made by outside entities are to include specific details to "be considered by DOE in determining that an emergency exists" and the appropriate intervention. 10 C.F.R. § 205.373. This includes "[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency," "[a] description of the situation and a discussion of why this is an emergency, . . . includ[ing] any contingency plan of the applicant and the current level of

implementation," and "[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts." 10 C.F.R. §§ 205.373(a)-(o).

Prior to 2025, DOE has used section 202(c) on only three occasions to delay the retirement of generation facilities[6]. These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close. Ex. 23-1 at 1 (DOE Order No. 202-05-3, December 20, 2005) (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24). The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility directly powered downtown D.C. and that, without

[6] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.

it, critical federal infrastructure faced an unacceptable risk of blackout.[7] *Id*. at 2. Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C. *Id*. at 3–4. Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility. *Id*. at 5–8. The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service. *Id*. at 10–11.

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from ENERGY. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair. And, construction of the new Unit No. 3 had been delayed because flooding in

[7] This incident eventually led to the statute's 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a section 202(c) order, leading the statute to read as it does today. *See* Rolsma, *supra*, at 806-08 (citing DEP'T OF ENERGY, ORDER NO. 202-05-3, December 20, 2005); 16 U.S.C. § 824a(c)(3)-(5).

Louisiana interfered with the fabrication of essential project materials. Ex. 24 (Letter Request of Grand River Dam Authority). The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first. Ex. 23-15 at 2 (DOE Order No. 202-17-1). The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes." *Id*.

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond. Ex. 23-16 at 1 (DOE Order No. 202-17-2). DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes." *Id*. at 2. DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order. Ex. 23-17 at Summary of Findings (DOE Order No. 202-17-4, Sept. 14, 2017). In its extension order, the Department continued to limit dispatch of the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units. Ex. 23-17 at 2 (DOE Order No. 202-17-4, September 14, 2017).

D. White House Strategy to Prop Up the Coal Industry

Since the 2025 Inauguration, the White House and DOE have sought to radically transform how section 202(c) of the Federal Power Act is applied—departing in almost every material respect from the longstanding approach described above. On January 20, 2025, his first day in office, President Trump issued Executive Order 14156, titled "Declaring a National Energy Emergency." 90 Fed. Reg. 8433. That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.[8] *See Id*. (providing no factual support for claimed emergency).

On April 8, 2025, President Trump issued Executive Order 14262, titled "*Strengthening the Reliability and Security of the United States Electric Grid*." 90 Fed. Reg. 15521 (April 14, 2025). The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective. Ex. 56 (New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*, April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025). This event, and the related Executive Orders, are part of several in a series of public

[8] That declaration is subject to a pending legal challenge by multiple states. *See* Complaint, *Washington v. Trump*, NO. 2:25-cv-00869 (W.D. WA May 9, 2025).

actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure." Executive Order 14262 at section 3(a). It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- of a process by which the developed methodology and any analysis results are regularly assessed; and,
- of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.

Executive Order 14262 section 3(b), (c).

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14156, *Declaring a National Energy Emergency*. Executive Order 14262, § 2. In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. President Trump has declared eight national emergencies in the first seven months of 2025 alone, and has invoked this power more in the first 100 days in office than any other President in modern

history. *See* Ex. 57 (Brennan Center for Justice, *Declared National Emergencies Under the National Emergencies Act*).

E. DOE's Section 202(c) Orders Preventing the Retirement of Fossil Fuel Power Plants Issued in 2025

Since January 20, 2025, DOE has issued orders to eight facilities under section 202(c) of the Federal Power Act, a sharp uptick from the less than one order per year issued on average from 2017-2024. *See* Ex. 23 (2025 DOE 202(c) orders). In late May 2025 DOE issued a pair of section 202(c) orders requiring fossil fuel generation facilities in Michigan and Pennsylvania that were each slated to retire the very next business day to remain on-line. Ex. 27 (U.S. Dep't of Energy, Order No. 202-25-3 (Campbell Order); *See* Ex. 28 (U.S. Dep't of Energy, Order No. 202-25-4 (Eddystone Order). Both the Campbell and Eddystone Orders have now been extended twice. Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025). These orders represent a marked shift in how section 202(c) has historically been used.

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any imminent emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy's service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE's

order for 90 days would approach $100 million. *See, e.g.*, Ex. 29 (Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025). Consumers Energy disclosed that continued operation of the plant in the first five weeks since the Order was issued resulted in a net financial impact of $29 million. *See* Ex. 30 (CMS Energy Corp., Quarterly Report (Form 10-Q), July 31, 2025); *See also* Ex. 31 (NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target*, June 16, 2025).

F. DOE Publishes Its Methodology and Reliability Standard to Guide Future Section 202(c) "Reliability Interventions"

On July 7, 2025, DOE published its "Report on Evaluating U.S. Grid Reliability and Security," which set forth the methodology and reliability standard that the Executive Order on grid reliability had mandated. Ex. 4 (U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, July 2025). DOE published this report without proving any public notice or comment period and without any apparent consultation with any grid operator or State. *See* Ex. 4 at i (acknowledging lack of data from regional and utility levels). Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE's analysis. Nor has DOE opened any administrative proceeding to otherwise involve the public in DOE's methodology and DOE has not published the Report in the Federal Register.

Nevertheless, DOE confirmed in the report that it would rely on the Resource Adequacy Report to justify future section 202(c) orders, consistent with the Executive Order's mandate. *See* Ex. 4 at vi (explaining that DOE's standard will be used to "guide reliability interventions"); *id.* at 1 (emphasizing the need for DOE's "decisive intervention" in energy

markets); *id*. at 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT"). As explained in an accompanying fact sheet, DOE would use the methodology to "prevent [] generation resources from leaving the bulk-power system." Ex. 32 (U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid*, 2025); *see also* Ex. 33 (Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security, July 7, 2025) (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act").

Due to numerous significant flaws in DOE's resource adequacy report that render it arbitrary and capricious, a number of states including Washington submitted a rehearing request to DOE on August 6, 2025. Ex. 35 (August 6, 2025 Rehearing Request). Among other things, the rehearing request pointed out that the Report was based on flawed and arbitrary assumptions and unsupported by substantial evidence because it failed to reasonably support its load growth assumptions and arbitrarily assumed 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same period, lacked sufficient regional granularity and suffered from other analytical flaws, and established an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act. *Id*. at 18–29. In addition, the report does not point to any sudden, unforeseen, or imminent circumstances that describe an "emergency" under the Federal Power Act to justify 202(c) orders, the report fails to consider existing reliability mechanisms, intrudes on state authority over generation facilities and non-emergency resource adequacy planning, and was adopted

subject to critical procedural flaws including failing to provide public notice and comment. *Id*. at 29–39.

DOE did not respond to the critiques raised by the States and other entities of its resource adequacy report and continues to rely on the resource adequacy report to justify emergency 202(c) orders. Rather, DOE denied the States' and other entities' requests for rehearing based on its assertion that the resource adequacy report was not an "'order' by which the State AGs are 'aggrieved' within the meaning of section 313 of the FPA." 313*l*. Ex. 35-2 (2025 State AG's Request for Rehearing of DOE Report).

G. DOE's 202(c) Emergency Order to TransAlta Requiring It To Continue To Be Available as a Coal-Fired Power Plant

On December 16, 2025, DOE issued a 202(c) order to TransAlta, requiring that Centralia remain ready to run as a coal-fired power plant beyond its scheduled closure date of December 31, 2025. Ex. 1. This Order, issued only 15 days before Centralia's scheduled closure as a coal plant, directed TransAlta to "take all measures necessary to ensure that Centralia Unit 2 is available to operate" at the direction of either the Balancing Authority or Reliability Coordinators for the region—which the Order identified as Bonneville Power Administration (BPA) and the California Independent System Operator Corporation (CAISO), respectively. Ex. 1 at 3. On March 13, 2026, DOE amended the Order, via Order No. 202-25-11B, identifying the Balancing Authority and Reliability Coordinator as Gridforce and Southwest Power Pool West RC. While this suggests that the plant should be kept on standby at the ready to run as needed, the Order also confusingly stated in footnote 11 that "continuous operation is required . . . so long as Secretary determines a shortage exists

and is likely to persist," to avoid the complications that could result from starting and stopping operations intermittently. Ex. 1 at 2, n. 11.

The order justifies DOE's invocation of its emergency authority under section 202(c) of the Federal Power Act due to the Secretary's determination of an "emergency situation" within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]" Ex. 1 at 1. Specifically, DOE's determination of an "emergency" is based on the NERC's 2025-2026 Winter Reliability Assessment, a September 2025 Power Point presentation on resource adequacy by Energy + Environmental Economics (E3), and DOE's July 2025 Resource Adequacy Report and two executive orders. *Id*. While the Order acknowledged that these sources found that "there is sufficient capacity for expected peak conditions," DOE asserted that there was a present emergency anyway due to an "elevated risk during periods of extreme weather." *Id*. That "elevated risk" contemplates a scenario in which, during a period of peak demand, extreme weather causes the outage of thermal power plants as well as adverse wind turbine conditions and, on top of that, similar extreme weather extends to neighboring regions so that the Northwest Region cannot import power. *Id*. The Order also cited accelerated load growth estimates out to 2030 and a shortfall in the development of adequate new capacity to meet this forecast demand. *Id* .

Finally, the Order cited the president's Executive Orders declaring a national energy emergency and on grid reliability for additional support and cited DOE's July 2025 resource adequacy report conducted under those executive orders for the proposition that "decisive intervention" to the Nation's power grid was necessary "to meet projected demand for

manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation." Ex. 1 at 2-3 (citing Ex. 4).

H. Impacts of Continued Coal Operations at Centralia

1. Deferred maintenance and upgrades make running Centralia as a coal plant difficult, expensive, and less reliable

TransAlta Centralia is an old facility and has not been maintained for continued operations beyond 2025 due to its planned retirement. Moreover, in recent years Centralia has been subject to frequent forced shutdowns due to breakdowns. For example, from 2023 through 2025 Centralia shutdown 29 times, 25 of which were forced outages, for issues such as needed "tube leak repairs." Ex. 11 at ¶ 7; Exs. 11-1 through 11-11 (Centralia Plant's quarterly reports submitted to SWCCA from 2023 through 2025).

Centralia's electrostatic precipitators (ESPs) that control its coal fly ash particulate matter emissions are failing—causing the plant's plume to register opacity levels approaching its 30% permit limit, even when operating below full load. Ex. 11 at ¶¶ 9–10; Ex. 11-12 (photograph of opacity readings on Oct. 23, 2025). In addition, Centralia has not been able to maintain the required control of its carbon monoxide (CO) emissions. Ex. 11 at ¶ 11; Ex. 11-3 (TransAlta Most Recent Quarterly Report). As described by TransAlta in its 2022 U2 Boiler Tune-up Report, this could be due to air leakage associated with cracks and holes that is impairing operation of fan components. Ex. 11 at ¶ 11; Ex. 11-13 (Centralia Plant's 2022 U2 Boiler Tune-up Report).

Skeleton crew staffing has and will further exacerbate the plant's proper functioning. For example, TransAlta's local air regulator, which conducts regular inspections, issued it two Notices of Violation in December 2025 for issues that may have been related to reduced

staffing and/or maintenance. Ex. 11 at ¶ 12. The first was related to excess emissions from the fly ash unloading baghouse and the second was for not fully engaging all relevant pollution control equipment prior to firing coal on startups. Exs. 11-14, 11-15 (SWCAA Notices of Violation No. 10642 and No. 10643).

TransAlta Centralia's coal-fired power also costs more, so ratepayers are likely to pay higher electricity bills to the extent there are continued coal-fired operations. Centralia power is priced significantly higher than the wholesale energy market price: $62.04 per MWh for Centralia versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15.

And DOE's order disrupts plans to strengthen reliability by converting Centralia to natural gas. As discussed above, TransAlta has announced plans and submitted permit applications to convert its plant from coal to natural gas in order to operate as a peaking plant under a commercial agreement with Puget Sound Energy. This conversion is in danger of being disrupted and delayed by DOE's order to continue operating Centralia as a coal plant. The risk of delay will compound over time if DOE continues to extend its Order repeatedly, as it has done for other plants such as the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania.[9] DOE's interference thus harms the ability of utilities to take steps they see as necessary to improve reliability—TransAlta Centralia as a natural gas peaker plant will provide grid services that an outdated coal plant cannot. Ex. 49 at ¶¶ 5–7 (Declaration of David Gomez).

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[9] *See* Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025).

2. Running Centralia results in health and environmental impacts

Continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonian's health (imposing direct harms on the State and its agencies), and impair visibility at Washington's iconic natural areas such as the Mount Rainer National Park. *See supra* pp. 13–18; *see also* Ex. 10. Centralia has been a significant source of air pollution in Washington including for particulate matter, sulfur dioxide, nitrogen oxides, dioxin and furans, mercury, heavy metals, and polycyclic aromatic hydrocarbons. Ex. 10 at ¶ 7; Ex. 52 at ¶ 8.

Those emissions are known to adversely impact human health. For example, dioxins and furans are highly toxic persistent environmental pollutants that can cause cancer, reproductive and developmental problems, damage to the immune system, and hormone disruption. Ex. 52 at ¶ 11. Mercury exposure poses especially significant health risks for pregnant women and infants because of its impacts on fetal development and infant health. *Id*.; Ex. 10 at ¶ 14. Polycyclic aromatic hydrocarbons (PAHs) cause a range of serious health risks including various cancers, respiratory and cardiovascular diseases, and reproductive health problems. Ex. 52 at ¶ 11.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above cleanup levels. *Id.* at ¶ 7. Continued aerial emissions of hazardous substances associated with TransAlta's coal operations have the potential to settle on and contaminate thousands of properties and create thousands of PLPs. *Id.* at ¶ 14. And the Centralia Coal Plant uses settling

ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15.

Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the continued operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million annually in Washington. Ex. 10 at ¶ 10. Moreover, even after the plant is converted to natural gas and begins operating again in 2028, the cleaner performance of the natural gas plant compared to coal-fired operations is expected to prevent an estimated 4–7 premature deaths, 2 nonfatal heart attacks, 24 cases of asthma onset, with an economic value of $68-110 million annually in Washington. Ex. 10 at ¶ 12. Children are acutely prone to these health risks because their bodies are still developing, and they have more exposure to airborne contaminants that settle on lawns, parks, and schoolyards. Ex. 52 at ¶ 10.

These health impact estimates are based on the assumption that Centralia continues to abide by the requirements of its environmental permits. Ex. 10 at ¶ 7. However, Centralia's most recent quarterly report and recent inspections of the facility indicate that maintenance on Centralia's pollution control equipment is due or overdue. Ex. 11 at ¶¶ 10-11. A local clean air agency also issued Centralia two notices of violation for exceeding emissions limits in December 2025. *Id*. at ¶ 12; Ex. 11-14 and Ex. 11-15. Therefore, emissions under emergency coal-fired operations may be even higher if TransAlta Centralia cannot operate at a lower load or make necessary repairs. *Id*. at ¶ 11.

In addition to these health impacts, TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural

areas, including at Mount Rainer National Park, located only 50 miles from the plant. And, because Centralia is the largest source of greenhouse gas emissions in Washington, Ex. 12, the continued coal-fired operations will also make it harder for Washington to achieve its statutory greenhouse gas emissions reduction requirements. *See* RCW 70A.45.020.

I. DOE's Section 202(c) Order Renewals

Since the sharp uptick in DOE's section 202(c) orders that started last year, DOE has issued six total extensions to two facilities. In August 2025, one day before the first order was set to expire, DOE issued a second section 202(c) order requiring the Campbell coal plant in Michigan to remain on-line. Ex. 58. DOE extended the order again in November 2025, and a third time in February 2026. Ex. 36, Ex 101 (February Campbell order). Similarly, DOE extended its original May 2025 order issued to the Eddystone Generating Station in Pennsylvania in August 2025, November 2025, and again in February 2026. Ex. 28, Ex. 59, Ex. 63, and Ex. 102 (February Eddystone order). In both of those cases, DOE failed to justify why emergency conditions persisted over the course of a year, aside from re-asserting that the region served by the Midcontinent Independent System Operator (MISO) faced *long-term* resource adequacy concerns.

DOE issued a renewal order for Centralia on March 16, 2026. Ex. 100. In addition to repeating its claims about speculative "periods of extreme weather" and potential long-term grid capacity issues, DOE cited to NERC's Long-Term Reliability Assessment and a preliminary injunction issued by the District Court for the District of Oregon to support the renewal of the Order. *Id.* As described in more detail below, DOE's reliance on both the NERC assessment and the preliminary injunction is problematic.

DOE's renewal order will exacerbate problems with Washington's grid by slowing the conversion to natural gas. For example, TransAlta cannot demolish the existing cooling towers, a necessary step in the conversion process, if it's required to remain available to operate. Ex. 103, Declaration of Clinton Lamoreaux at ¶ 6 (Second Lamoreaux Decl.); Ex. 103-1. The first order also proved unnecessary, because TransAlta did not operate as a coal plant, even during a six-day outage by the largest non-hydroelectric generating facility in the state. Ex. 104 (Second Moriyasu Decl.) at ¶ 3, 6.

J. TransAlta Applied for Permits for Its Planned Natural Gas Conversion

Prior to DOE's December section 202(c) order, TransAlta targeted late 2028 to begin commercial operations at the natural gas facility conversion that would replace its coal facility. Ex. 41 at ¶ 6. The December 202(c) order required TransAlta to "take all measures necessary to ensure that Centralia Unit 2 is available to operate . . ." Ex. 1 at 3. That effectively delayed, or at least made uncertain, TransAlta's natural gas conversion. Although TransAlta is still taking steps to move forward with the planned conversion, further 202(c) orders could significantly delay that process.

One of the first steps in the planned conversion is to obtain the necessary environmental permits. The Department of Ecology issues Prevention of Significant Deterioration (PSD) permits for major modifications to existing sources that will trigger an increase in certain air emissions. TransAlta needs the PSD permit prior to beginning actual construction of the natural gas plant. TransAlta submitted its PSD permit application to Ecology on December 24, 2025. Ex. 105 (Lim Decl.) at ¶ 6; Ex. 105-1. On January 23, 2026, Ecology sought more information from TransAlta, and on March 10, 2026 TransAlta

responded with the requested information, which Ecology is still evaluating. Ex. 105-1 at ¶¶ 7–8; Ex. 105-2; Ex. 105-3.

TransAlta has also submitted its Air Discharge Permit Application to the Southwest Clean Air Agency (SWCAA) in preparation for its planned conversion. The Air Discharge Permit is also a prerequisite to construction. Ex. 103 at ¶ 6.

TransAlta's Air Discharge Permit application indicates that it will replace the existing cooling towers with new units. Ex. 103-1 (Air Discharge Permit Application). Although TransAlta needs to obtain air quality permits to begin construction, it does not need permits to begin the demolition process of those existing cooling towers or other activities that are not considered construction. Once TransAlta receives its necessary permits, which Ecology and SWCAA both anticipate occurring by late summer or early fall 2026, TransAlta can commence actual construction of the natural gas facility. Ex. 103 at ¶ 8; Ex. 105 at ¶ 9 (Ecology is the lead SEPA agency and anticipates that the SEPA process will be completed before the PSD permit is issued). However, TransAlta will not be able to undertake demolition and other pre-construction activities, or commence construction of the natural gas facility, if DOE continues to issue 202(c) orders.

K. Columbia Generating Station Outage

Washington's largest non-hydroelectric generating facility is the Columbia Generating Station (CGS) nuclear power facility. Ex. 104 at ¶ 3. An unplanned outage at CGS can result in a significant loss of generation capacity in Washington. CGS produces ten percent of the energy produced by the Total Electric Power Industry in the state—enough to power one million homes. *Id.* However, in the event of an unplanned outage at CGS, or any other

generating facility in Washington, other facilities ramp up their generation to compensate for that loss and keep the grid functioning at capacity.

That scenario played out in February of 2026, when CGS experienced an unplanned outage due to an issue with the cooling system that supports the reactor's recirculation pumps. *Id.* at ¶ 4. At 2:49 a.m. on February 12, the nuclear plant unexpectedly shut down. *Id*. CGS alerted the Nuclear Regulatory Commission of the outage by 9:25 a.m. *Id.* CGS did not come back online until February 18. *Id.*

Despite the six-day outage, there were no blackouts during the period that CGS was offline. In fact, BPA maintained net generation greater than net demand during the entire duration of the outage. *Id.* at ¶ 6. The gap in supply was primarily filled by hydro and wind resources. *Id.* at Figure 1 (Hourly Generation Mix in BPA Balancing Authority).

During Centralia I, TransAlta Centralia's coal-fired power was not once needed or used to balance the grid or serve load. Although Centralia was available to operate as a result of the first order, and the grid experienced a 10% loss of total supply as a result of the CGS outage, Centralia power was not necessary during the six-day CGS outage. *Id.* at 6.

V. REQUEST FOR REHEARING

In addition to the grounds laid out in Washington's request for rehearing in Centralia I, fully incorporated as set out herein, Washington provides the following additional grounds for rehearing of Centralia II.

A. The NERC 2025-2026 Winter Reliability Assessment Still Does Not Establish an Emergency

It is somewhat unclear the extent to which Centralia II relies on the NERC 2025-2026 Winter Reliability Assessment. Centralia II cites to the Witner Assessment in its background

section as a basis for the Secretary's determination that an emergency existed with regard to the Original Order. Ex. 100 at 2. While the "emergency situation" section of Centralia II does not reference the Winter Assessment, *see id. at* 3–5, that section notes that "[t]he emergency conditions that necessitated the issuance of [Centralia I] continue, both in the near and long term." *Id*. at 3. To the extent that DOE relies on the Winter Assessment as a basis for Centralia II, that reliance is misplaced.

For one, the Winter Assessment—along with its description of the WECC Northwest as at an "elevated" risk for power shortages under "extreme" conditions—expired on February 28, 2026, over two weeks before DOE issued Centralia I. Ex. 2 at 5–6. More critically, and as set out in Washington's request for rehearing of Centralia I, the Winter Assessment fails to support a conclusion that there is an "emergency" within the meaning of section 202(c) even were the WECC Northwest still listed as at elevated risk. As Washington noted in January, NERC's criteria for "elevated risk," a step below the "high" risk category, is not a forecast of an imminent emergency. *See id.* at 11. NERC itself acknowledges this, concluding that "the results of the probabilistic assessment reveal no [Expected Unserved Energy] or [Loss of Load Hours] for Winter 2025–2026." *Id*. at 15, Table 5. Moreover, the Winter Assessment actually predicted a 3.3% *increase* in the Northwest's reserve margin compared to the previous year, even presuming planned retirements, including Centralia. *Id*. at 37, 49.

This partly explains why Centralia was not required to run for the entire duration of Centralia I, even though the Northwest did experience an unplanned loss of generating capacity during that time. As discussed above, the Columbia Generating Station, the

Northwest's largest non-hydropower energy generation facility experienced an unexpected outage from February 12, 2026, through February 18, 2026. Ex. 104, at ¶ 4. Despite this outage—which occurred during Washington's peak winter demand and where Centralia also was not running—there were no energy shortages in the Northwest. *Id*. at ¶¶ 5–6. This power situation is expected to continue well into the future. As the U.S. Energy Information Administration notes, hydropower in the Pacific Northwest is projected to increase as "overall precipitation" remained near the 30-year average. Ex. 119 (EIA, Short-Term Energy Outlook, (Apr. 7, 2026)).

In short, to the extent the Winter Assessment is relied upon here, it did not establish an emergency when it was valid and, obviously, does not support one now that it has expired.

B. NERC's Long Term Resource Adequacy Report Does Not Support DOE's Finding of Emergency Conditions in the Short or Long Term

DOE arbitrarily relies on NERC's January 2026 Long Term Resource Adequacy Report ("LTRA") to justify its finding that emergency conditions exist in the short or long term. *See* Ex. 100 at 3; *see also* Ex. 106. To the contrary, the LTRA demonstrates the absence of emergency conditions for the next three years. Although the LTRA noted potential reliability risks beginning in 2029, those stem from forecasts for projected data center demand that may not materialize. Potential data center demand cannot justify an emergency order.

Agency action is arbitrary and capricious when the agency "entirely failed to consider an important aspect of the problem, [or] offered an explanation for its decision that runs counter to the evidence before the agency." *Motor Vehicle Mfrs. Ass'n v. State Farm*, 463 U.S. 29, 43, 103 S. Ct. 2856, 77 L. Ed. 2d 443 (1983). Here, DOE arbitrarily fails to consider the LTRA's finding of normal risk from 2026 through 2029—a key aspect of the LTRA that

contradicts DOE's assertion that emergency conditions exist in the short and long-term. DOE's reliance on the LTRA is also arbitrary and unsupported because DOE fails to acknowledge or address the shortcomings and inherent flaws in NERC's analysis, as described further below. Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported. *See WildEarth Guardians v. U.S. Bureau of Land Mgmt*., 870 F.3d 1222, 1236–7 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies' affirmative duty to examine key assumptions underlying their policies). An agency "may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties." *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).

1. The LTRA found no reliability risks in the Northwest from 2026 through 2028

NERC's LTRA found that the WECC-NW was at normal risk for the years 2026, 2027, and 2028. *See* Ex. 106 at 8. "Normal risk" means the area is "expected to have sufficient resources under a broad range of assessed conditions and [is] below the lowest risk criteria level." *Id*. at 6. DOE arbitrarily fails to explain how a report finding that the region is at the lowest risk criteria level could possibly support its finding that emergency conditions exist in the Northwest. *See also* Ex. 107, Declaration of Nikhil Kumar (explaining the LTRA does not provide evidence of a reliability emergency).

2. NERC's finding that the Northwest faces "high" reliability risks from 2029 through 2030 is not a reliable or accurate prediction of what is likely to happen in the Northwest

NERC also found the WECC-NW to be at high risk in years 2029 and 2030 based on forecasted demand growth, primarily from data centers. Ex. 106 at 8. Aside from the fact that

2029 is still *years* into the future, the LTRA's analysis does not support an emergency finding here. NERC's projections are not "predictions of what will happen" for multiple reasons. Ex. *Id*. at 5. First, they are a snapshot in time, based on "information supplied in July 2025," nine months before DOE issued Centralia II. *See id*. DOE arbitrarily fails to account for the current conditions when declaring an emergency situation, especially where—as here—its emergency is premised on highly variable and unpredictable demand from potential data centers. *See* Ex. 108 (GridStrategies, *Review of NERC's 2025 Long-Term Reliability Assessment* 18–24 (March 5, 2026)); Ex. 107 at ¶ 7.

Second, NERC's information sources are also imperfect. NERC primarily relies on utility projections, *see* Ex. 102 at 9, although those forecasts are variable and uncertain. Utility reports on new generation capacity are not uniform and may inaccurately account for the capacity availability during peak load. *See* Ex. 108 at 10; Ex. 107 at ¶ 8. NERC's data also appears to differ from the Lawrence Berkeley National Laboratory data in critical ways, which may be due to error, different processing methods, collection periods, and resource accreditation methods. *See* Ex. 108 at 10, 43.

Utility demand forecasts also tend to overestimate demand growth for multiple reasons, including an incentive to overstate load growth to justify additional rate-based investments in generation and other infrastructure. *See id*. at 19; *see also* Ex. 109 (Juan Pablo Carvallo, et al., Lawrence Berkeley Lab, *Load Forecasting in Electric Utility Integrated Resource Planning* (2016)) (studying ten years of load forecasts from western utilities and finding systematic overestimates in load growth).

Potential loads from data centers further complicate the picture. As NERC acknowledges, large loads "inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions." Ex. 106 at 9. Other variables further complicate accurate projections of future demand, including limited supplies of computer chips, the practice of data centers seeking interconnection in multiple areas and thus being "double-counted" in load forecasts, and state and local policies to limit data center growth. *See* Ex. 108 at 19–20.

This is all true in Washington as well, where policymakers are actively developing new laws, regulations, and other tools to manage future growth in data centers. *See, e.g.,* Ex. 110 (Wash. Dep't of Revenue, *Data Center Workgroup: Preliminary Report* (Dec. 2025)). For example, in March 2026, the Washington UTC opened a policy docket "to proactively explore the effects of emerging large loads." Ex. 111 (Notice of Hybrid Technical Conference at 1). The docket will be used to "develop[] principles and policies related to large loads seeking service from and interconnection with investor-owned electric utilities (electric IOUs) subject to the Commission's jurisdiction," and will conclude with "a policy statement that offers principles and policies regarding large load interconnection with electric IOUs." *Id*.

Third, NERC's LTRA then applies this potentially outdated, uncertain and unreliable data to an asymmetrical set of assumptions that tend to both overestimate future demand and underestimate future supply. The LTRA includes all loads with "development commitments necessary to drive grid planning studies," but only counts generators who have "completed all planning studies and signed an interconnection agreement." Ex. 108 at 19. NERC also

excludes non-firm interregional electricity flows that are historically available to meet demand. *See id*. at 4–6; Ex. 107 at ¶ 8.

Changing any one of these assumptions or data inputs dramatically shifts the picture, and projected risk level, in the Northwest and across the country. *See* Ex. 108 at 4–6, 10; Ex. 107. As just one example, if NERC had used the same data as the Lawrence Berkeley National Laboratory for Tier 1 generation (and qualified under the standard region-specific accreditation methods), the Northwest falls from high to normal risk in 2030. Ex. 108 at 39. Significantly, this would not be the first time that data discrepancies led NERC to erroneously classify a region to be "high risk." *See* Ex. 112 (NERC, *Statement on NERC's 2024 Long-Term Reliability Assessment* (Jun. 25, 2025).

Fourth, DOE fails to consider an important aspect of the problem, which is that, if data center demand really does materialize as forecasted and the new generation truly fails to develop in time to serve it, those new large loads will not be allowed to interconnect if they will pose reliability risks to the grid. *See* Ex. 113 at 4–5, 7 (NERC, *Comments on Large Load ANOPR* (Nov. 2025) (describing NERC Reliability Standards and FERC Interconnection agreements that provide a "first line of defense" to protect against reliability risks from new large loads … "NERC's measured approach efficiently and effectively mitigates risks to reliability"). While the UTC does not have jurisdiction to prevent a utility from interconnecting with new large loads, it can strongly disincentivize a utility interconnection it finds imprudent by preventing cost recovery. *See* RCW 80.04.015. DOE's assumption that, if emergency action is not taken, the Northwest *will* be at "high risk" in 2029 is thus fatally incorrect.

NERC's practice of reliability assessment may make sense when used as intended: "to inform industry, policymakers, and regulators" about potential future needs of a system. Report 5. The LTRA highlights that policymakers and regulators will need to balance the potential future electricity needs of technology and cryptocurrency mining companies with the needs of other electricity users and the American public to keep electricity affordable, clean, and reliable. Significantly, there is no evidence that Northwest regulators will allow cost recovery of those large loads to connect if doing so would pose the reliability risks that NERC's LTRA identified. As described further below, however, NERC's assumptions and methods do not make sense when used as a tool for identifying emergency conditions that justify federal intervention into business plans and matters normally reserved for state jurisdiction.

3. Relying on NERC's LTRA to justify an emergency order violates the Federal Power Act

Relying on NERC's LTRA to justify an emergency, forcing Northwest ratepayers to pay for a coal power plant they do not need now, but *may* need four years down the line is also unlawful in violation of the Federal Power Act. As described in Washington's first rehearing request, the Federal Power Act does not allow DOE to find emergencies and order plants to stay open based on potential emergency conditions that may not occur for years into the future. *See* Centralia I Rehearing Request at 41–53. This is especially true when there is no substantial evidence that those conditions are likely to materialize—especially considering that the "high risk" would essentially assume that state regulators allowed cost recovery for large loads to connect to the grid even though it posed serious reliability risks. Such an

interpretation of "emergency" in Section 202(c) goes far beyond any reasonable interpretation of the term.

C. Columbia River Power System Restrictions Imposed by the Oregon District Court do not Threaten Grid Reliability

DOE asserts that regional electricity reliability is threatened by restrictions imposed on the Federal Columbia River Power System by a preliminary injunction issued by the United States District Court for District of Oregon. Ex. 100 at 3–4. DOE asserts that these restrictions will impact BPA's ability to provide reliable power and transmissions services, resulting in a "substantially increase[d] risk" to regional power reliability. *Id*. at 4.

These assertions are fundamentally flawed on multiple levels. As discussed below, DOE here relies on arguments from briefing dealing with a proposed injunction that was not issued, rather than the injunction actually issued by the court with critically different terms. Moreover, the district court's injunction, in the end, specifically accommodated power reliability concerns by allowing more water for power generation, routine flexibility for energy needs, and exceptions providing relief from operational conditions if there were an energy reliability emergency. Ex. 114-1 at 17–19 (*Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, No. 3:01-CV-640-SI, Amended Preliminary Injunction Order (D. Or. Mar. 2, 2026)). And the arguments and evidence relied on by DOE were considered and, where not specifically addressed by the final terms of the injunction, were rejected by the court as unsupported. *Id.* DOE's reliance on the injunction to support its emergency finding is wholly misplaced.

As a threshold matter, Centralia II fails to cite the applicable version of the district court's preliminary injunction order, even though it was available well before DOE issued

Centralia II on March 16, 2026. Instead, DOE cites the court's original order granting the preliminary injunction, issued February 25, 2026. Ex. 100 at 4, n.23. But, in response to a motion for clarification, the court issued an Amended Opinion and Order and an amended preliminary injunction on March 2, 2026, a full two weeks prior to DOE's issuance of the Renewal Order. Ex. 114. DOE's reliance on an outdated and inapplicable court order epitomizes arbitrary agency action and falls far short of the standards and rigor that should accompany invocation of emergency powers under Section 202(c) the Federal Power Act. Like DOE's failure to name the correct Balancing Authority and Reliability Coordinator in Centralia I, DOE's continued "shoot from the hip" approach with regard to Centralia and other coal facilities illustrates the reckless and illegal nature of its current section 202(c) practice.

But even putting aside the fact that DOE relies on an invalid order, the arguments and evidence of a threat to grid reliability DOE cites here were already acknowledged—*and addressed*—by the district court. DOE parrots arguments made by the Federal defendants in the preliminary injunction briefing and relies on evidence of the effects of the plaintiffs' proposed preliminary injunction on the electricity grid. But the court did not enter the Plaintiffs' requested preliminary injunction and instead crafted injunctive relief that addressed electricity reliability concerns in critical ways that DOE entirely fails to acknowledge or take into account in its Centralia II. Ex. 114-1 at 17–19.

First, in response to the very power reliability concerns that had been raised, the district court rejected the plaintiffs' request to set reservoir levels at Minimum Operating Pool ("MOP") and instead ordered reservoir levels to be maintained at the higher Minimum Irrigation Pool ("MIP") level, affording more water for electricity production as well as for

irrigation. *Id*. at 17. These are not the reservoir levels that were the subject of the briefing and evidence relied on now by DOE to assert that the injunction will cause grid instability. For example, Centralia II cites BPA staff declarations that evaluated power reliability impacts for the reservoir forebay levels at the plaintiffs' requested MOP level, not the MIP level ultimately set by the court in the injunction. Ex. 100 at 4; *see* Ex. 115, Dibble Decl. at ¶¶ 19, 28, 40; Ex. 116, Stevenson Decl. at ¶¶ 21, 24–27. As the court noted, setting reservoir levels at MIP rather than MOP, significantly ameliorated the concerns relating to power system reliability, as well as concerns with flood risk, transportation, irrigation, and availability of water supplies and clean drinking water. Ex. 114-1 at 17.

Second, DOE fails to account for the fact that the court included specific relief valves from the conditions of its preliminary injunction related for electricity reliability. The court included these relief valves for both the reservoir levels as well as spill conditions. Ex. 114-2 at 41-42 (*Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, No. 3:01-CV-640-SI, Amended Opinion and Order (D. Or. Mar. 2, 2026)) ("the Court includes flexibility of the Action Agencies to deviate from these [reservoir] levels for transportation and power generation emergencies . . . [and] builds into the injunction flexibility for the Action Agencies to adjust spills for emergency power generation and transportation needs"). Thus, before the preliminary injunction could cause any energy emergency, relief from its provisions is plainly available. DOE acknowledges none of this in Centralia II.

The district court also rejected many of the Federal Defendant's grid reliability concerns (such as their concerns with spill provisions) as overblown, unsupported, and contrary to the scientific record in the case. *Id*. at 38. The court observed that recent Columbia

River System operations with spill conditions and reservoir levels similar to what is imposed in the preliminary injunction have consistently been workable and not resulted in grid instability. *Id*. In fact, the court noted that since 2023 the Northwest Power and Conservation Council (the organization responsible for assessing regional power demand and reliability) "has found the regional power system to be reliable and anticipates that the system will continue to meet reliability standards." *Id*. (citing Ex. 117, Hirsch Decl. ¶¶ 12–18); *see also* Ex. 114-2 at 10-11 (recounting 2023 stay of litigation and MOU). The court went on to find that "the routine variances and adjustments that have helped to support that reliability will continue to be available to Federal Defendants under the injunction." *Id*.

In sum, DOE's assertions in Centralia II regarding the district court's injunction are based on outdated briefing and an outdated version of the district court's ruling and injunction. In reality, the preliminary injunction affecting operation of the Columbia River Power System does not represent a risk to regional energy reliability. Not only did the court address, *and reject*, this very argument in its detailed ruling, it went to some length to accommodate power reliability concerns in crafting its injunction. The injunction neither threatens grid reliability nor substantially increases the risk of an electricity reliability emergency. DOE's reliance on it here to declare a continuing "emergency" in Centralia II is arbitrary, capricious, and unlawful.

D. Interpreting Section 202(c) to Allow "Emergency" Orders Based on Long-Term Energy Needs and Planning Decisions Would Violate Procedural Due Process

As Washington explained in its prior rehearing request, section 202(c) applies only during an "emergency," i.e., circumstances that are both imminent and unforeseen. *See* Centralia I Rehearing Request at 44–50. DOE's apparent interpretation of Section 202(c) to

encompass circumstances that are neither imminent nor unforeseen raises serious constitutional concerns. "When 'a serious doubt' is raised about the constitutionality of an Act of Congress, 'it is a cardinal principle that this Court will first ascertain whether a construction of the statute is fairly possible by which the question may be avoided.'" *Jennings v. Rodriguez*, 583 U.S. 281, 296 (2018) (quoting *Crowell v. Benson,* 285 U.S. 22, 62 (1932)). DOE's interpretation is not reasonable, *see* Centralia I Rehearing Request at 44-50, but even if it were, the doctrine of constitutional avoidance would prevent a court from accepting it.

DOE's use of section 202(c) for Centralia raises more than just a serious constitutional concern, DOE's Centralia orders have violated Washington's right to procedural due process. "The fundamental requirement of due process is the opportunity to be heard 'at a meaningful time and in a meaningful manner.'" *Mathews v. Eldridge*, 424 U.S. 319, 333 (1976). In assessing the requirements of procedural due process, courts consider (1) the private interest that will be affected by the official action, (2) the risk of an erroneous deprivation of such interest through the procedures used, and the probable value, if any, of additional or substitute procedural safeguards, and (3) the Government's interest, including the function involved and the fiscal and administrative burdens that the additional or substitute procedural requirement would entail. *Id*. at 335.

DOE's emergency orders affect property and sovereign interests. The order intercepts plans for power plant owners to use or retire the facilities that they own. FERC has relied on DOE's orders to require ratepayers to pay for plant operations that they may not need. And the orders intrude on states' sovereign interest over power generation and resource adequacy planning. *See* Centralia I Rehearing Request at 50-56. In this case, Washington's sovereign

interests and property interest as a ratepayer and on behalf of its citizens are affected. Washington also has a property interest in maintaining its contractual agreement with TransAlta to retire Centralia at the end of 2025.

The risk that Washington and others are erroneously deprived of these protected interests is high. Section 202(c) allows DOE to issue emergency orders without any advance notice to the affected parties or meaningful opportunity to be heard before the order takes effect. That has borne out here. DOE issued, and now renewed, the Centralia order without any notice to Washington, TransAlta, or the Northwest ratepayers who will eventually be asked to pay for DOE's order. While DOE theoretically offers an after-the-fact opportunity to request rehearing, this is not a meaningful opportunity to be heard. Washington duly requested rehearing on January 13, 2026, but DOE did not respond to that request before the Centralia I order expired. DOE then issued Centralia II, still without responding to Washington's objections to Centralia I. And now DOE has sought to delay judicial review of Centralia I in the Ninth Circuit because it still needs to "fully consider administrative challenges to the order." *See* U.S. Department of Energy Mot. to Extend Admin. Record Deadline, *Washington v. Dep't of Energy*, No. 26-1252 (9th Cir. Mar. 20, 2026).

As described in this rehearing request and Washington's request for rehearing of Centralia I, DOE's orders are arbitrary, unsupported by substantial evidence, and based on false or misguided understandings of the Northwest energy system. Case in point: DOE issued Centralia I without naming the correct parties, an error which DOE did not correct until right before Centralia I expired. *See* Centralia I Rehearing Request at 70-71; Ex. 118. When DOE intervenes in electricity markets without notice or any advance opportunity to be heard (and

delays responding to objections to its action for months after the fact), the chance that it misses crucial information, omits key details, or fails to account for important aspects of the alleged "emergency" it is attempting to resolve.

Finally, the relevant government interest in ensuring a reliable and affordable electricity system favors more procedural protections, not less. As Washington previously explained, DOE's orders undermine the Northwest's energy market, increase electricity rates, and harm consumers. *See* Centralia I Rehearing Request at 88-96. DOE has offered no explanation why it could not offer more notice or a hearing before issuing Centralia I or II. Centralia's planned retirement has been known for over a decade, and DOE cites no emergent event that prevented it from consulting with the affected parties before issuing, and subsequently renewing, the Centralia orders.

If section 202(c) were limited to "emergencies," as in circumstances that are both imminent and unforeseen, then the procedural due process balancing of factors would be different. But, under DOE's interpretation of "emergency,"[10] DOE arrogates to itself the power to overtake power plant owners' plans for their facilities, supersede state sovereign authority over power generation and resource adequacy planning, and impose costs on ratepayers for power generation they did not agree to buy. DOE asserts this power while simultaneously providing no procedural protections in the administrative process.

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[10] *See* Resp'ts Final Answering Br., *Michigan v. Dep't of Energy*, No. 25-1159 (9th Cir. Apr. 10, 2026) (arguing that section 202(c) does not require imminence or an unexpected development and allows for renewal of emergency orders potentially for years).

VI. REQUEST FOR STAY

Washington State further moves DOE for a stay of the Order until judicial review has concluded. 18 C.F.R. § 385.212. DOE has the authority to issue a stay under the Administrative Procedure Act where "justice so requires." 5 U.S.C. § 705.

To determine whether to grant a request for stay, agencies consider: (1) whether the requesting party will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

A. Washington State Will Suffer Irreparable Injury Without a Stay

A stay is necessary to prevent irreparable harm to Washington State caused by Centralia II. Injuries must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (identifying that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").

Economic injury is irreparable only where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958). Environmental injury, however, "can seldom be adequately

remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

Centralia II imposes costs on Washington ratepayers that may not be recoverable through future litigation and would not have otherwise been expended absent the Centralia II. Assuming TransAlta complies with Centralia II,[11] it will expend considerable costs preparing the plant for refiring—if the plant is idle but available to operate *or* actively producing coal-fired power. *See supra* Section III at 10-11, Section IV.H.1. TransAlta will continue to generate staffing and overhead expenses under either scenario. Firing up the plant and transmitting electricity will further increase expenses. And plainly, coal is more expensive. Ex. 41 at ¶ 15 ("Under its current Purchase Power Agreement (PPA), the energy price from Centralia's coal is significantly higher than the wholesale energy market price. Specifically, under the current contract, Puget Sound Energy pays $62.04 per MWh, while the wholesale market price is $54.32 per MWh."). Centralia II again directs TransAlta to recover its expenses through a FERC tariff revision. Order at 4; 16 U.S.C. § 824a(c). Neither Centralia II nor the statute identify a mechanism for "corrective relief" should Centralia II be found unlawful. As there is no clear recourse to recovering these costs should Washington State prevail in its challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases.

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[11] There is no indication that TransAlta will not comply with the Order, to the extent it understands what the Order requires it to do.

Environmental injury is inevitable whether Centralia II requires TransAlta to immediately operate Centralia as a coal plant, or it operates intermittently from a stand-by posture. As described in the Rehearing Request, Washington residents will suffer environmental health and environmental harms because of the Centralia II. *See supra* Section III at 8, Section IV.H.3. TransAlta's Centralia Coal Plant is a significant source of particulate matter, sulfur dioxide, and nitrogen oxides. Ex. 10 at ¶ 7. Those emissions are known to adversely impact human health. Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the failure to cease operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million in health care costs and lost economic activity in Washington annually. Ex. 10 at ¶ 10. Further, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12; Ex. 13. A local clean air agency issued Centralia two notices of violation for exceeding emissions limits in December 2025. Ex. 11 at ¶ 12. Emissions are expected to be even higher if Centralia cannot operate at a lower load or make necessary repairs, or cease operations entirely as it had planned to do prior to DOE's orders. Ex. 11 at ¶ 11. Because the environmental injury to Washington State and its residents cannot be adequately remedied and may be permanent or long duration and is sufficiently likely, a stay pending judicial review is necessary.

B. A Stay Would Not Substantially Harm Other Parties

No parties would be harmed by a stay of Centralia II because no emergency exists and the Centralia II was never needed to begin with. As detailed above, an order under 202(c) must be limited to circumstances that are imminent and unforeseen. *See supra* VI.A. Centralia

II again provides no evidence to support a claim of an imminent emergency and references potential *future* grid unreliability. *See supra* VI.C.1. The State supplies substantial evidence to support the absence of an energy emergency. Because no current emergency exists, no other party could be harmed. Not forcing the deployment of coal plant that is not needed harms no one. A stay would not disrupt the local energy market or impair the provision of electricity to customers.

C. A Stay is in the Public Interest

Centralia II is contrary to the public interest. A stay will prevent any potential harm to the public that will be caused by the Centralia II. Principally, Centralia II fails to meet the public interest standard under the Act DOE relies upon, i.e., 16 U.S.C. § 824a(c)(1), in bringing Centralia II. *See* Centralia I Rehearing Request VI.D.2. Further, if a true energy emergency existed, the public interest would not be served by an aging, unreliable coal plant that requires 12-18 hours to start up. Ex. 11 at ¶¶ 7, 8. Centralia II has the potential to throw the regional energy market into short-term and long-term uncertainty, both of which could have adverse consequences for energy users—the public. *See* Centralia I Rehearing Request VI.E.1. A stay is in the public interest.

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VII. CONCLUSION

For the reasons set forth above, Washington respectfully requests that DOE grant intervention, grant rehearing, and rescind Centralia II in its entirety.

Dated this 14th day of April, 2026.

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State of Washington

Request for Rehearing of Order No. 202-26-18

Index of Exhibits

No.	Exhibit Name	Document Name	URL
Centralia I			
1	DOE Order No. 202-25-11	Department of Energy (DOE), Washington DC 20585, Order No. 202-25-11 (Dec. 16, 2025)	
2	NERC 2025–2026 Winter Reliability Assessment	North American Electric Reliability Corporation, 2025–2026 Winter Reliability Assessment (Nov. 2025)	
3	E3 Slide Deck	Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results, dated September 22, 2025	
4	DOE Resource Adequacy Report	DOE Resource Adequacy Report, Evaluating the Reiliability and Security of the U.S. Electric Grid (July 2025)	

No.	Exhibit Name	Document Name	URL
5	Memorandum of Agreement	Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Dec. 23, 2011)	
6	2017 Amended Memorandum of Agreement	First Amendment to Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Jul. 13, 2017)	
7	2011 BART Order	Dep't of Ecology Administrative Order, First Revision: Order No. 6426 (Dec. 13, 2011)	
8	2020 BART Order	Dep't of Ecology Administrative Order, Second Revision: Order No. 6426 (Jul. 29, 2020)	
9	Technical Support Data-2020 BART Order	Dep't of Ecology Technical Support Document for Second BART Order Revision, TransAlta Centralia Generation Plant (July 2020)	

No.	Exhibit Name	Document Name	URL
10	Palcisko Declaration	Declaration of Gary Palcisko in Support of Request for Rehearing by State of Washington	
10-1	COBRA Data Coal v. Cease Operations	Total Health Benefits, Lewis County, Washington	
10-2	COBRA Data Coal v. Natural Gas	Total Health Benefits, Lewis County, Washington	
10-3	2023 Emissions Inventory	2023 Emissions Inventory	
11	Lamoreaux Declaration	Declaration of Clinton Lamoreaux in Support of Request for Rehearing by State of Washington	
11-1	TransAlta Centralia Title V Quarterly Report First Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan. 1 - March 31, 2025	

No.	Exhibit Name	Document Name	URL
11-2	TransAlta Centralia Title V Quarterly Report Second Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, April 1-June 30, 2025	
11-3	TransAlta Centralia Title V Quarterly Report Third Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2025	
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11-6	TransAlta Centralia Title V Quarterly Report Third Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2024	

No.	Exhibit Name	Document Name	URL
11-7	TransAlta Centralia Title V Quarterly Report Fourth Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, Fourth Quarter, Oct. 1 – Dec. 31, 2024	
11-8	TransAlta Centralia Title V Quarterly Report First Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan. 1 – Mar. 31, 2023	
11-9	TransAlta Centralia Title V Quarterly Report Second Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, Apr. 1 – Jun 30, 2023	
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11-11	TransAlta Centralia Title V Quarterly Report Fourth Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Fourth Quarter, Oct. 1 – Dec. 31, 2023	

No.	Exhibit Name	Document Name	URL
11-12	Photograph of opacity readings	Photograph of opacity readings on Oct. 23, 2025	
11-13	Centralia Plant's 2022 U2 Boiler Tune-up Report	TransAlta Centralia U2 Boiler, 40 CFR 63 DDDDD Tune-Up Report (Oct. 3, 2022)	
11-14	Notice of Violation No. 10642, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Oct. 23, 2025	
11-15	Notice of Violation No. 10643, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Jan 11, Mar. 4, Jun. 6, Jun. 11, Aug. 26, 2025	
12	Top 10 Stationary Sources of GHG Emissions in WA – 2022	Dep't of Ecology Data Base: Top 10 Stationary Sources of Greenhouse Emissions in Washington (2022)	

No.	Exhibit Name	Document Name	URL
13	2023 EPA Top CO2 Emissions	U.S. Env't Prot. Agency, Greenhouse Gas Reporting Program (GHGRP), Top Washington Greenhouse Gas emissions sources for 2023, *GHGRP State and Tribal Fact Sheet* (last visited Jan. 6, 2026)	https://www.epa.gov/ghgreporting/ghgrp-state-and-tribal-fact-sheet
14	U.S. Energy Information – Start Up	U.S. Energy Information Administration, Owen Comstock, *About 25% of U.S. power plants can start up within an hour* (Nov. 19, 2020)	https://www.eia.gov/todayinenergy/detail.php?id=45956)
15	Plant Job Underway	Centralia Daily Chronicle, *Plant Job Underway* (Jun. 14, 1968)	
16	2021 Title V Air Operating Permit	TransAlta Centralia Generation, LLC, Centralia Plant, Air Operating Permit SW-98-8-R5A, Southwest Clean Air Agency (Sep. 22, 2021)	

No.	Exhibit Name	Document Name	URL
17	2021 Title V Air Operating Permit - Basis Statement		
18	U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860)		https://www.eia.gov/electricity/data/eia860/
19	2022 Visibility SIP	Washington Dep't of Ecology, Air Quality Program, *State Implementation Plan Revision, Second Regional Haze Plan* (2018 – 2028) (Jan. 2022)	
20	TransAlta News Release Announcing Coal to Gas Conversion Project	TransAlta, Alberta Calgary, News Release, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/

No.	Exhibit Name	Document Name	URL
21	TransAlta Permit Application	TransAlta Centralia Generation, LLC, *Prevention of Significant Deterioration Permit Application* (Dec. 2025)	
22	Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Long-term Resource Adequacy Meeting* (Nov. 19, 2025)	
23	2025 DOE 202(c) Orders	2025 DOE 202(c) Orders	https://www.energy.gov/ceser/2025-doe-202c-orders
23-1	Order (Dec. 14, 2000)	U.S. Dep't of Energy, Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000) (California Energy Crisis in 2000)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

No.	Exhibit Name	Document Name	URL
23-2	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-3	DOE Order No. 202-05-2 (Sep. 8, 2005)	DOE Order No. 202-05-2 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-4	DOE Order No. 202-08-1 (Sep. 14, 2008)	DOE Order No. 202-08-1 (Sep. 14, 2008) (Hurricane Ike)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-5	DOE Order No. 202-20-1 (Aug. 27, 2020)	Ex. 23-9 (DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-6	DOE Order No. 202-20-2 (Sep. 6, 2020)	DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-7	DOE Order No. 202-21-1 (Feb. 14, 2021)	DOE Order No. 202-21-1 (Feb. 14, 2021) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-8	DOE Order No. 202-21-2	DOE Order No. 202-21-2) (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

No.	Exhibit Name	Document Name	URL
23-9	DOE Order No. 202-22-1	DOE Order No. 202-22-1 (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-10	DOE Order No. 202-22-2	Exs. 23-13 and 23-14 (DOE Order Nos. 202-22-1 & 2 and amendments) (same)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-11	DOE Order No. 202-22-3 (Dec. 23, 2022)	DOE Order No. 202-22-3 (Dec. 23, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-12	DOE Order No. 202-22-4 (Dec. 24, 2022)	DOE Order No. 202-22-4 (Dec. 24, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-13	DOE Order No. 202-24-1 (Oct. 9, 2024)	Ex. 23-20 (DOE Order No. 202-24-1 (Oct. 9, 2024)) (Hurricane Milton)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-14	DOE Order No. 202-05-3 (Dec. 20, 2005)	DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant, DC)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-15	DOE Order No. 202-17-1	DOE Order No. 202-17-1 (GRDA)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

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23-16	DOE Order No. 202-17-2	DOE Order No. 202-17-2 (Yorktown Power Station)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-17	DOE Order No. 202-17-4 (Sept. 14, 2017)	DOE Order No. 202-17-4 (Sept. 14, 2017) (Yorktown Power Station – extension)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
24	Grand River Dam Authority Request for Emergency Order	Daniel S. Sullivan, Grand River Dam Authority, *Re: Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (April 11, 2017)	https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf
25	Wagner Order No. 202-25-6	U.S. Dep't of Energy, Order No. 202-25-6 (Jul 28, 2025)	
26	Puerto Rico Electric Power Authority, Order No. 202-25-1	U.S. Dep't of Energy, Order No. 202-25-1 (May 16, 2025)	
27	Campbell Order	U.S. Dep't of Energy, Order No. 202-25-3 (May 23, 2025)	https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf https://perma.cc/Q7P7-TDTX

No.	Exhibit Name	Document Name	URL
28	Eddystone Order	U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025)	https://perma.cc/PS3M-6CJA
29	Trump Admin Ordered Coal Plan Stay Open	Ella Nilsen, CNN, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill* (June 6, 2025)	https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright
30	CMS Energy Quarterly Report	U.S. Securities and Exchange Commission, Form 10-Q, *Quarterly Report for CMS Energy Corp.* (Jul. 31, 2025)	https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm
31	Trump Administration Forcing Coal Plants to Stay Open	NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025)	https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first

No.	Exhibit Name	Document Name	URL
32	U.S. Dep't of Energy Fact Sheet	U.S. Dep't of Energy, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025)	https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf https://perma.cc/YLX7-8G7T
33	Press Release Dep't of Energy U.S. Grid Report	Press Release, U.S. Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security https://perma.cc/8TEJ-AGH6
34	Campbell Rehearing Order	U.S. Dep't of Energy, Order No. 202-25-3B, Order Addressing Arguments Raised on Rehearing (Sep. 8, 2025	

No.	Exhibit Name	Document Name	URL
35	August 6, 2025 State Request for Rehearing	Before the U.S. Dep't of Energy, In Re: Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, July 2025, Motion to Intervene and Protective Request for Rehearing (Aug. 6, 2025)	
35-1	August 6 Rehearing Request Exhibit A	North American Electric Reliability Corp (NERC) *Interregional Transfer Capability Study (ITCS)*, Final Report, Nov. 2024	
35-2	August 6 Rehearing Request Exhibit B	GridLab Analysis: Department of Energy Resource Adequacy Report (July 15, 2025)	
35-3	August 6 Rehearing Request Exhibit C	New York University School of Law, Institute for Policy Integrity, *Enough Energy A Review of DOE's Resource Adequacy Methodology* (July 2025)	

No.	Exhibit Name	Document Name	URL
35-4	August 6 Rehearing Request Exhibit D	Nicholas Institute for Energy, Environment & Sustainability, *Rethinking Load Growth* (2025)	
35-5	August 6 Rehearing Request Exhibit E	London Economics Internat'l, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* (Jul 7, 2025)	
35-6	August 6 Rehearing Request Exhibit F	Grid Strategies, *Resource Adequacy Value of Interregional Transmission* (Jun. 2025)	
36	Second Campbell Order	U.S. Dep't of Energy, Order No. 202-25-9 (Nov. 18, 2025)	
37	Schahfer Order	U.S. Dep't of Energy, Order No. 202-25-12 (Dec. 23, 2025)	
38	Culley Order	U.S. Dep't of Energy, Order No. 202-25-13 (Dec. 23, 2025)	

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39	PJM Manual	Capacity Market & Demand Response Operations, *PJM Manuel 18: PJM Capacity Market* (Effective Date: Jul. 23, 2025)	
40	Eddystone Request for Rehearing	Before the U.S. Dep't of Energy, Order No. 202-25-4, Motion to Intervene and Request for Rehearing	
41	Moriyasu Declaration	Declaration of Callahan Moriyasu in Support of Request for Rehearing by State of Washington	
41-1	Historic Trends in Energy Use	Northwest Power and Conservation Council, *Historic Trends in Energy Use*	
41-2	Northwest Heat Wave	U.S. Energy Information Administration, *Northwest heat wave leads to record levels of summer electricity demand* (Aug. 23, 2017)	

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41-3	Ancillary Services Definitions and Capability Study	GE Energy Consulting, Ancillary Services Definitions and Capability Study (Dec. 2012)	
41-4	Optimizing Reserves	Electricity Advisory Committee, *Optimizing Reserves* (Oct. 2019)	
41-5	Historical Data	Bureau of Reclamation, Historical Data Access, Grand Coulee Dam (2020-2025)	https://www.usbr.gov/pn/hydromet/arcread.html
41-6	Washington Water Conditions	USGS Water Data for the Nation, *Washington Water Conditions* (Dec. 31, 2025)	
41-7	Water Management Data	U.S. Army Corps of Engineers, *Water Management Data* (Dec. 31, 2025)	
41-8	Grand Coulee Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Manage-ment Data, Grand Coulee Dam, Pacific Northwest Region, Dec. 2025	

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41-9	Chief Joseph Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Chief Joseph Dam, Pacific Northwest Region, Dec. 2025	
41-10	Lower Granite Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Lower Granite Lock and Dam, Walla Walla District, Dec. 2025	
41-11	Little Goose Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Little Goose Lock and Dam, Walla Walla District, Dec. 2025	
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41-13	Ice Harbor Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Ice Harbor Lock and Dam, Walla Walla District, Dec. 2025	

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41-14	McNary Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, McNary Lock and Dam, Pacific Northwest Region, Dec. 2025	
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41-18	Priest Rapids Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Priest Rapids Dam, Pacific Northwest Region, Dec. 2025	

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41-19	Wanapum Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Wanapum Dam, Pacific Northwest Region, Dec. 2025	
41-20	Rock Island Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Rock Island Dam, Pacific Northwest Region, Dec. 2025	
41-21	NOAA NWS Three Month Outlook	NOAA, Nat'l Weather Service, *Three-Month Outlooks*, Official Forecasts Jan-Feb-Mar 2026	
41-22	Centralia Coal PPA (R)	Puget Sound Energy, Docket UE-250747, Attachment B (Impact of portfolio updates), *Sheet "Centralia Coal PPA(R)"* (Oct. 1, 2025)	
41-23	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025–2030	

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42	Press Release Re: Executive Order	U.S. Dep't of Energy, *Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter* (Dec. 17, 2025)	
43	Promises Made Promises Kept	U.S. Dep't of Energy, *Promises Made, Promises Kept, Unleashing the Golden Era of Energy Dominance and Lowering Prices* (Dec. 18, 2025)	
44	Executive Order 14156	Administration of Donald J. Trump, 2025, Executive Order 14156- Declaring a National Energy Emergency (Jan. 20, 2025)	
45	E2 Clean Economy Works: Nov. 2025 Analysis	Michael Timberlake, E2 Economy + Environment, Clean Economy Works: November 2025 Analysis (Dec. 12, 2025)	

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46	Energy Department Announces Termination of 223 Projects	U.S. Dep't of Energy, *Energy Department Announces Termination of 223 Projects, Saving Over $7.5 Billion* (Oct. 2, 2025)	
47	Archive of Energy Reliability and Resilience	U.S. Dep't of Energy, Office of Energy Efficiency & Renewable Energy, *Energy Reliability and Resilience*	
48	Dep't of Energy Response to State Rehearing Request of August 6	U.S. Dep't of Energy, *Re: August 6, 2025 Submission* (Sep. 5, 2025)	
49	Gomez Declaration	Declaration of David C. Gomez in Support of Request for Rehearing by State of Washington	
49-1	Centralia Power Plant Profile	S&P Capital IQ, Centralia Power Plant Profile	
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50	Reeves Declaration	Declaration of Andrew Reeves in Support of Request for Rehearing by State of Washington	
50-1	Puget Sound Energy 2023 Electric Progress Report	Puget Sound Energy, *2023 Electric Progress Report*, Chapters 1-9 (2023)	
50-2	2025 Avista Electric Integrated Resource Plan	Avista, *Electric Integrated Resource Plan* (2025)	
50-3	Puget Sound Energy 2021 Integrated Resource Plan	Puget Sound Energy, *2021 PSE Integrated Resource Plan,* Chapters 1-9 (Apr. 2021)	
50-4	Letter Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting* (Dec. 31, 2025)	

No.	Exhibit Name	Document Name	URL
50-5	Jan 2024 Month In Review	Nat'l Weather Service, Pendleton OR, *The Month In Review, January 2024*	
50-6	WRAP Assessment of January 2024	WRAP, *Assessment of January 2024 Cold Weather Event*	
50-7	Reliability Coordinator Procedure, No. RC-410	California ISO, RC West, Reliability Coordinator Procedure, RC0410 (May 1, 2025)	
50-8	Western Energy Imbalance Market (WEIM)	Western Energy Markets	https://www.westernenergymarkets.com/western-energy-imbalance-market-weim
50-9	CAISO WEIM Fact Sheet	California Independent System Operator (CAISO) Fact Sheet, *Western Energy Imbalance Market* (WEIM)	https://www.caiso.com/Documents/western-energy-imbalance-market-fact-sheet.pdf
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50-12	RC West California ISO	California ISO, RC West	https://www.caiso.com/market-operations/products-services/rc-west
51	Nightingale Declaration	Declaration of Joel Nightingale in Support of Request for Rehearing by State of Washington	
51-1	Testimony of Ronald J. Roberts, RJR-1T	Washington Utilities and Transportation Commission, Docket Nos. UE-240004 and UG-240005, Prefiled Direct Testimony of Ronald J. Roberts (Feb. 15, 2024)	
51-2	Winter Reliability and Electric-Gas Coordination Slides for WUTC Resource Adequacy Meeting	Zapotocky, Electric Reliability & Security for the West, *Winter Reliability and Electric-Gas Coordination*; North American Electric Reliability Corporation (NERC), *NERC's Winter Reliability Assessment* (Nov. 4, 2025)	

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51-4	Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025	U.S. Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook in 2025* (Apr. 2025)	https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2025_LCOE_report.pdf
51-5	Generating Resource Reference Plants: Natural Gas	Northwest Power and Conservation Council, *Generating Resource Reference Plants, Natural Gas*	https://www.nwcouncil.org/2021powerplan_natural-gas_generating-resource-reference-plants/
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52	Middleton Declaration	Declaration of Thomas Middleton in Support of Request for Rehearing by State of Washington	
52-1	Model Toxics Control Act	Washington Dep't of Ecology, Model Toxics Control Act	https://ecology.wa.gov/spills-cleanup/contamination-cleanup/rules-directing-our-cleanup-work/model-toxics-control-act (Last visited January 5, 2026)
52-2	TransAlta Agreed Order	Washington Dep't of Ecology, Agreed Order No. DE 24235 with TransAlta Centralia Generation LLC for TransAlta Centralia (Dec. 29, 2025)	
52-3	Quick Facts Centralia WA	U.S. Census Bureau, Quick Facts Centralia (last visited Jan. 8, 2026)	https://www.census.gov/quickfacts/fact/table/centraliacitywashington/RTN131222
52-4	Data USA	Data USA, Centralia WA, Metropolitan Statistical Area (last visited Jan. 8, 2026)	https://datausa.io/profile/geo/centralia-wa-31000US16500

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53	Rybarik Declaration	Declaration of Brian Rybarik in Support of Request for Rehearing by State of Washington	
54	FEMA Declaration of Emergency	U.S. Dep't of Homeland Security, FEMA, *Emergency Declaration*, FEMA-3629-EM (Dec. 9, 2025)	
55	Best Practices Resource Planning	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024, Revised Dec. 2024)	https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf https://perma.cc/D68F-WHWQ

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57	Declared National Energencies	Brennan Center for Justice, Declared National Emergencies under the National Emergencies Act	https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act
58	Campbell Order No. 202-25-7	Dep't of Energy Order No. 202-25-7 (Aug 20, 2025)	
59	Eddystone Order No. 202-25-8	Dep't of Energy Order No. 202-25-8 (Aug. 27, 2025)	
60	Trump Order Keep Michigan Power Plant Open	Tom Perkins, *Trump Order to Keep Michigan Power Plan Open Costs Taxpayers $113m* (Nov. 28, 2025)	https://www.theguardian.com/us-news/2025/nov/28/trump-michigan-power-plant
61	Short-Term Energy Outlook Browser	U.S. Energy Information Administration, Short-Term Energy Outlook Data Brower (Dec. 9, 2025)	https://www.eia.gov/outlooks/steo/data/browser

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63	Eddystone Order No. 202-25-10	Dep't of Energy Order No. 202-25-10 (Nov. 25, 2025)	
64	Winter Outlook 2025-2026	US Dep't Commerce, Nat'l Oceanic and Atmospheric Admin., Nat'l Weather Service, *Winter Outlook 2025-2026*, at 4 (Last visited Jan. 6, 2025)	https://www.weather.gov/media/abr/sitreport/2025-2026WinterOutlook.pdf
65	TransAlta Signs Agreement	*TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion*, TransAlta (Dec. 31, 2025, 9:39 AM)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

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67	Best Practices Resource Planning (PDF Exhibit Parts 1-7)	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024)	https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf
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73	Trump Wants Mining	Hannah Northey, EENews, T*rump wants mining. Federal mine safety workers are on the chopping block* (Sep. 5, 2025)	. https://www.eenews.net/articles/trump-wants-mining-federal-mine-safety-workers-are-on-the-chopping-block/

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74	Grid Strategies Report	Michael Goggin, Grid Strategies LLC, The Cost of Federal Mandates to Retain Fossil-Burning Power Plants (Aug. 2025)	
75	Notice to Stakeholders	U.S. Dep't of Labor, Mine Safety and Health Admin., *Notice to Stakeholders*	https://www.msha.gov/notice-stakeholders
76	Columbia River Basin Dams	U.S. Army Corps of Engineers, NW Division Website, *Columbia River Dams* accessed Dec. 30, 2025)	https://www.nwd.usace.army.mil/crwm/cr-dams/
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80	Pacific Moisture Drenches the U.S. Northwest	NASA Earth Science, *Pacific Moisture Drenches the U.S. Northwest* (Dec. 12, 2025)	https://science.nasa.gov/earth/earth-observatory/pacific-moisture-drenches-the-u-s-northwest/
81	President Approves Washington Emergency Declaration	U.S. Dep't of Homeland Security, FEMA, *President Donald J. Trump Approves Emergency Declaration for State of Washington* (Dec. 12, 2025)	https://www.fema.gov/press-release/20251212/president-donald-j-trump-approves-emergency-declaration-state-washington
82	Federal Teams Support State-Led Response to Washington Storms	U.S. Dep't of Homeland Security, FEMA, *Federal Teams Support State-Led Response to Historic Washington Severe Storms and Flooding* (Dec. 23, 2025)	https://www.fema.gov/blog/federal-teams-support-state-led-response-historic-washington-severe-storms-and-flooding

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84	Electricity Data Browser	U.S. Energy Info. Admin., *Electricity Data Browser*, EIA (last visited Nov. 4, 2025)	https://www.eia.gov/electricity/data/browser/#/topic/7
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87	Trends in Financial Hardship	United for Alice, *The State of Alice in Washington*, United Way of Northern New Jersey	https://www.unitedforalice.org/trends-in-hardship/Washington

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88	Emission Performance Standard SB 1368	California Energy Commission, Emission Performance Standards – SB 1368	https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/emission-performance-standard-sb-1368
89	Coal and the Environment	U.S. Energy Information Administration, *Coal explained: Coal and the environment* (Last updated: Apr. 17, 2024)	https://www.eia.gov/energyexplained/coal/coal-and-the-environment.php
90	What They are Saying: President Trump Stops Radical Environ-mentalism	The White House Newsletter, *What They Are Saying: President Trump Stops Radical Environmentalism to Generate Power for the Columbia River Basin* (Jun. 13, 2025)	https://www.whitehouse.gov/articles/2025/06/what-they-are-saying-president-trump-stops-radical-environmentalism-to-generate-power-for-the-columbia-river-basin/

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93	NCR11393 Compliance Audit	Gridforce Energy Management, LLC, Compliance Audit, NCR11393 (Dec. 20, 2019)	
94	Craig Order No. 202-25-14	U.S. Dep't of Energy, Order No. 202-25-14 (Dec. 30, 2025)	

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95	Research Power Corp. Order Authorizing Electricity Exports to Canada	U.S. Dep't of Energy, Grid Deployment Office, Research Power Corporation, GDO Docket No. EA-365-C, Order Authorizaing Electricity Exports to Canada	
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97	Declaration of Arne Olson	U.S. of America, Before the Dep't of Energy, Re: Transalta Centralia Generation, Declaration of Arne Olson (Jan. 13, 2026)	
97-1	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025-2030	

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98	Final Order Granting Petition	Washington Utilities and Transportation Commission, Re: Puget Sound Energy, Docket UE-121373, Order 03, Final Order Granting Petition, Subject to Conditions (Jan. 9, 2013)	
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101	February Campbell Order	Dep't of Energy, *Order No. 202-26-16* (Feb. 17, 2026)	

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102	Eddystone Order	Dep't of Energy, *Order No. 202-26-17* (Feb. 23, 2026)	
103	Second Lamoreaux Declaration	Second Declaration of Clinton Lamoreaux in Support of Motion to Intervene, Request for Rehearing, and Motion to Stay by State of Washington (Apr. 14, 2026)	
103-1	Air Discharge Permit Application	Tetra Tech, *Air Discharge Permit Application, TransAlta Centralia Generation, LLC* (Jan. 2026)	
103-2	Completeness determination for air discharge permit application	Letter from Southwest Clean Air Agency to TransAlta Centralia Generation *re: Completeness Determination for Air Discharge Permit Application L-760* (Feb. 25, 2026)	
104	Second Moriyasu Declaration	Declaration of Callahan Moriyasu in Support of Second Rehearing Filing (Apr. 13, 2026)	

No.	Exhibit Name	Document Name	URL
105	Lim Declaration	Declaration of Mengchiu Lim in Support of Motion to Intervene, Request for Rehearing and Motion to Stay by State of Washington (Apr. 14, 2026)	
105-1	TransAlta PSD Permit Application	Tetra Tech, *Prevention of Significant Deterioration Permit Application, TransAlta Centralia Generation, LLC, Lewis County, Washington* (Dec. 2025)	
105-2	Ecology Incom-pleteness Letter	Letter from Dep't of Ecology to TransAlta Centralia Generation, LLC– *Incompleteness Letter for the TransAlta Centralia Plant Project* (Jan. 23, 2026)	
105-3	TransAlta Incom-pleteness Letter Response	Letter from TransAlta to Dep't of Ecology re: *Incompleteness Letter Response for the TransAlta Centralia Plant Project* (Mar. 10, 2026)	

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107	Kumar Declaration	Declaration of Nikhil Kumar in Support of Motion to Intervene, Request for Rehearing, and Motion to Stay by State of Washington (Apr. 13, 2026)	
107-1	Sylvan Analytics Review of E3 Report	Sylvan Energy Analytics, *Near-term winter resource adequacy challenges in the Pacific Northwest, A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges* (Jan. 2026)	
107-2	Koomey Analytics Data Center Forecasts	Koomey Analytics, *Separating Fact from Fiction in Data Center Electricity Forecasts, A Guide for Regulators* (Mar. 2026)	

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107-4	NERC to Dial Down RTO's Risk Level	Cook, RTO Insider, *MISO: NERC to Dial Down RTO's Risk Level; Members Create Large Load Working Group* (Mar. 25, 2026)	
108	GridStrategies Report	GridStrategies, *Review of NERC's 2025 Long-Term Reliability Assessment* (Mar. 5, 2026)	https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf
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111	UTC Notice of Hybrid Technical Conference	Utilities and Transportation Commission, *Notice of Hybrid Technical Conference* (Apr. 7, 2026)	https://www.utc.wa.gov/casedocket/2026/260162/docsets
112	NERC Statement on LTRA	North American Electric Reliability Corp., *Statement on NERC's 2024 Long-Term Reliability Assessment* (Jun. 25, 2025)	https://www.nerc.com/newsroom/statement-on-nercs-2024-long-term-reliability-assessment
113	NERC Comments on Large Load	Before the Federal Energy Regulatory Commission, Docket No. RM26-4-000, *Comments of the North American Electric Reliability Corporation in Response to Notice Inviting Comments* (Nov. 21, 2025)	https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2025/large_load_anopr_comments_final_digicert.pdf
114-1	Nat'l Wildlife Fed'n v. NMFS Injunction	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Amended Preliminary Injunction Order* (Mar. 2, 2026)	

No.	Exhibit Name	Document Name	URL
114-2	Nat'l Wildlife Fed'n v. NMFS Order	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Amended Order Granting Preliminary Injunction* (Mar. 2, 2026)	
115	Dibble Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Rachel Dibble in Support of Federal Defendants' Opposition to Plaintiffs' Motions for a Preliminary Injunction* (Dec. 12, 2025)	
116	Stevenson Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Audrey Stevenson in Support of Federal Defendants' Opposition to Plaintiffs' Motions for a Preliminary Injunction* (Dec. 11, 2025)	

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117	Hirsch Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Nancy Hirsh in Support of Plaintiffs' Reply in Support of Motion for Preliminary Injunction* (Jan. 22, 2026)	
118	BPA FOIA Response	Dep't of Energy, Bonneville Power Administration Letter to Megan Sallomi, Wash. Attorney General's Office, EPA Division, *Response to Request for Agency Records via FOIA* (Feb. 19, 2026)	
119	US EIA Outlook	Short-Term Energy Outlook, April 7, 2026	https://www.eia.gov/outlooks/steo/report/elec_coal_renew.php

EXHIBIT 136

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-28

MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, the State of Washington, by and through the Washington State Attorney General, Nicholas W. Brown, moves to intervene and for a stay, and requests that the Department of Energy ("DOE") grant rehearing of Order No. 202-26-28 (June 12, 2026) ("Centralia III"), attached hereto as Exhibit 120. Centralia III extends for an additional 90 days Order No. 202-26-18 (Mar. 16, 2026) ("Centralia II"), which itself extended for an additional 90 days Order No. 202-25-11 (Dec. 16, 2025) ("Centralia I"). Because the legal and factual issues here directly overlap and repeat the same matters as related to Centralia I and II, Washington hereby incorporates by reference its requests for rehearing of Order No. 202-25-11 and Order No. 202-26-18, including all arguments, exhibits, and other reference materials, and reasserts them herein as grounds for rehearing Centralia III.

I. INTRODUCTION

On December 16, 2025, DOE issued the Centralia I order to TransAlta Centralia Generation LLC directing that the Centralia Coal Plant ("TransAlta Centralia" or "Centralia") remain in operation as a coal facility. Centralia I was counterproductive to its own aims, failing to establish any actual emergency and threatening to derail the long-planned conversion of

TransAlta Centralia into a modernized natural gas facility with greater capacity and more flexibility than the current aged coal facility. DOE extended the order first in March and now does so again in June, tripling down to issue a third flawed emergency order for a situation that time has now confirmed is a non-emergency.

DOE should immediately withdraw Centralia III. As with Centralia I and II, the Centralia III order is unlawful, internally inconsistent, misguided, and based on incorrect assertions about the Northwest's power infrastructure and operation. DOE again makes assertions of unfettered authority to usurp state and regional power planning based on generalized long-range concerns. This again violates the Federal Power Act, which expressly limits DOE's authority to *actual* emergency situations involving war or the sudden and unexpected loss of power.

An emergency did not exist in December 2025, did not exist in March 2026, and does not exist now in June and July. Indeed, no emergency ever materialized, and the TransAlta Centralia plant has not been needed to run at any point. As a result, Centralia III again fails to present any legitimate factual basis—let alone substantial evidence—to support its claim that maintaining Centralia as a coal-fired facility is necessary to "meet" any emergency. And, as with Centralia I and II, Centralia III is detrimental to the public interest by undermining the very grid stability it purports to protect in a way that will be enormously burdensome to the Northwest's rate payers. The longer DOE holds Centralia hostage for purely political aims, the greater the risk of delay becomes in converting this aging, unreliable, and polluting plant to a larger, modernized, and critical source of power for the region. Washington calls on DOE to rescind Centralia III.

II. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

Washington incorporates its statement of issues and specifications of error from its petitions for rehearing of Orders No. 202-25-11 and Order No. 202-26-18. Washington submits the following additional statement of issues and specifications of error:

- Centralia III is arbitrary, capricious, and not based on substantial evidence because Centralia III's reliance on the North American Electric Reliability Corporation Summer Reliability Assessment to establish an energy emergency is misplaced.

- Centralia III is arbitrary, capricious, and not based on substantial evidence because it ignores the comments of BPA, CAISO, Gridforce, and SPP in FERC proceedings that show that DOE's order is arbitrary and capricious and will harm ratepayers

- Centralia III is arbitrary, capricious, and not based on substantial evidence because it relies on a district court injunction related to the Columbia River Power System and fails to account for—let alone even acknowledge—that the injunction has express provisions for dealing with emergency circumstances.

III. MOTION TO INTERVENE AND INTERVENOR'S INTEREST

The State of Washington moves to intervene in this proceeding and become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. *See* RCW 43.10.030(1). *See also City of Seattle v. McKenna*, 172 Wash. 2d 551, 259 P.3d 1087 (2011) (noting that RCW 43.10.030(1) grants the Attorney General discretionary authority to act in any forum "on a matter of public concern" (internal quotations and citations omitted). The TransAlta Centralia Plant is located in the State of Washington, and the State is aggrieved by the Order in several ways.

First, Washington has a direct contractual interest in the retirement of Centralia on December 31, 2025. In 2011, the Washington Legislature passed the Coal-Fired Electric Generation Facilities Bill, SB 5769. S.B. 5769, 62nd Leg., (Wash. 2011). That Act directed

Centralia to comply with the state's greenhouse gas emission performance standards by the end of 2020 for its first boiler and the end of 2025 for the second. RCW 80.80.040(c). It also directed the Governor to enter into a Memorandum of Agreement with the owners of Centralia. RCW 80.80.100. The State and TransAlta signed the Memorandum of Agreement in 2011, which was amended in 2017 to specify that Centralia could continue to generate power, so long as it was not coal-fired power. Ex. 5 (2011 MOA); Ex. 6 at section 1 (amending Subsection D(5) of the MOA) (2017 MOA Amendment).

The Memorandum of Agreement required Centralia to permanently cease coal power generation from one boiler in 2020, and the other boiler in 2025. Ex. 5; Ex. 6. In exchange for that commitment, the State of Washington confirmed that the facility met the greenhouse gas emissions performance standards and other environmental requirements of the State, guaranteed the ability of TransAlta to enter into long-term power contracts for the sale of electricity from Centralia, and promised to maintain sales and use tax exemptions for the plant. Ex. 5. The State of Washington kept those promises, sacrificing tax revenue and granting TransAlta flexibility with regard to operational controls in exchange for Centralia ceasing coal operations by the end of 2025. *See, e.g.*, RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax); RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and

remediation costs in rates).[1] Because the Order deprives Washington of the benefit of its bargain under the Memorandum of Agreement, Washington suffers distinct harms as a result of the Order.

Second, Washington has a direct regulatory interest in Centralia's retirement by the end of 2025 because continued coal-fired operations will directly violate state law as well as a regulatory order issued by the Department of Ecology. Centralia is subject to Washington's emissions performance standard (EPS) for baseload electric generation in the state, RCW 80.80.040. The EPS is essentially a carbon intensity standard, limiting the volume of greenhouse gas emissions that an electric generating facility may emit per megawatt-hour of power produced. RCW 80.80.040(1), (3). This standard cannot generally be met by coal-fired plants without employing carbon sequestration technology.[2] The application of this standard was delayed for TransAlta until the scheduled shutdown of its two boilers at the end of 2020 and 2025. RCW 80.80.040(3)(c) ("A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020,

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[1] *See e.g.* RCW 82.08.811 (exempting the sale of coal from the state Retail Sales Tax); RCW 82.12.811 (exempting coal from the state Use Tax); RCW 70A.65.080(7)(c) (exempting Centralia from the greenhouse gas limits of the Climate Commitment Act); RCW 19.405.030 (allowing Centralia to recover its decommissioning and remediation costs in rates).

[2] The emission performance standard is currently set at 876 GHG/MWh. WAC 173-407-130 (setting forth EPS standard in Ecology's EPS rules). *See* RCW 80.80.040(1)(providing procedures for setting standard); RCW 80.80.050 (setting out Washington Department of Commerce's role to set standard); WAC 194-26-020 (Washington Department of Commerce setting standard).

and any other generating boiler is in compliance by December 31, 2025: [referencing process for setting standard].").

TransAlta relied on the 2025 retirement of its last coal-fired boiler as its means of complying with Washington's emissions performance standard. Ex. 7 at 2, §D(a)(1) (2011 BART Order) ("The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the [coal-fired] units."). Further, the Washington Department of Ecology issued Centralia a regulatory order imposing Best Available Retrofit Technology ("BART") requirements pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART order specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition; Ex. 8 at 3, condition 3 (2020 BART Order, Revision 2). Thus, continued operations of TransAlta's coal-fired boilers, without substantial investment in new emissions-lowering technology, will directly violate Washington's Emission Performance Standard and BART order.

Third, Washington residents will suffer health and environmental harms because of Centralia III, with costs to the State resulting from the heightened burden on state-provided insurance and public hospitals. As detailed below, continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonians' health imposing direct harms on the State and its agencies, and impair visibility at Washington's iconic natural areas such as the Mount Rainer National Park. Ex. 10 at ¶ 7 (Declaration of Gary Palcisko).

Fourth, these environmental harms will frustrate Washington State's regulatory interests, harm the State's public trust resources, and pose a financial burden to the State. For example, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12 (Top 10 Stationary Sources of GHG Emissions in WA, 2022); Ex. 13 (Top Washington Greenhouse Gas Emissions Sources, 2023). By mandating the continued operation of the Centralia Coal Plant, Centralia III will make it harder for Washington to meet its statutory greenhouse gas emissions reduction requirements. RCW 70A.45.020. And continued burning of coal will also hinder Washington's investigation and cleanup of the site under the Model Toxics Control Act (MTCA). *See* Ex. 52 at ¶ 16 (Declaration of Thomas Middleton). Under MTCA, the Washington Department of Ecology is responsible for investigating contamination, developing cleanup action plans, and identifying potentially liable parties (PLPs) for sites contaminated with hazardous substances. *Id.* at ¶ 4-14.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above MTCA cleanup levels. *Id.* at ¶ 7. Centralia III will prolong the contamination of the Site, exacerbating the time and resources the State must expend to investigate and plan its cleanup. *Id.* at ¶ 14. Centralia III will also cause continued aerial emissions of hazardous substances, which have the potential to settle on and contaminate thousands of properties and create thousands of potentially liable parties under MTCA. *Id.* at ¶ 14. Determining liability and cleanup responsibility for so many sites is resource-intensive for the State. *Id.* Finally, the Centralia Coal Plant uses settling ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15. Centralia III will require TransAlta

to continue using the settling ponds, preventing the Washington Department of Ecology from performing cleanup of the ponds, and potentially posing risks related to groundwater contamination. *Id.*

Fifth, Washington's electricity grid will be less reliable because of Centralia III. In addition to the direct interest in grid reliability to power state buildings, public schools, and hospitals, Washington has a regulatory interest in maintaining grid reliability.[3] Centralia experiences extended periods of non-operation. In the years 2023-2025, the Centralia Plant Unit #2 shut down 29 times, 25 of which were forced outages. Ex. 11 at ¶ 7 (Declaration of Clinton Lamoreaux). Additionally, when coal-powered generation facilities do shut down, they have a longer start-up time than natural-gas-powered facilities, which makes them less responsive to fluctuating energy demands. Ex. 14 (Owen Comstock, *About 25% of U.S. power plants can start up within an hour,* U.S. ENERGY INFO. ADMIN., November 19, 2020). This is especially true for "cold" startups, where the facility must start up after an extended period of nonactivity. Cold startups take longer than startups following a briefer outage where the facility components are still warm from recent operation. Ex. 11 at ¶ 8. It took Centralia anywhere from 11 to 18 hours to reach its operational capacity during the six cold startups from the fourth quarter of 2024 through the third quarter of 2025. *Id.* Plus, because Centralia

[3] The Washington Utilities and Transportation Commission (UTC) is tasked with regulating IOUs such that any services rendered are "adequate and efficient," RCW 80.28.010(2), (11); RCW 19.405.080(2)(a) (reporting requirements concerning reporting on meeting load, reliability standards, and resource adequacy); RCW 80.28.130 (granting UTC authority to order an electric utility to make improvements to their system to "secure adequate service or facilities").

is likely overdue for maintenance, it could face more frequent shutdowns than in previous years. Ex. 11 at ¶ 10-11.

This will be exacerbated by the apparent staffing shortages Centralia faces. Ex. 11 at ¶ 12. Finally, aside from in limited circumstances, Washington utilities are prohibited from purchasing power from coal plants after December 31, 2025. RCW 19.405.030. Because of these frequent shutdowns, the length of time needed to start up the plant, the uncertainties around maintenance and staffing, and the legal barriers to purchasing power from Centralia, coal operations at Centralia are less reliable, efficient, or economical than other alternatives. However, Centralia III will force ratepayers to pay for Centralia's operations rather than investing in alternatives, resulting in a loss of capacity and flexibility for Washington's electricity grid.

Sixth, Washington agencies, households, and businesses will likely pay higher electricity bills because of Centralia III, and Washington has a regulatory interest in keeping electricity rates fair and affordable.[4] Under the most recent Power Purchase Agreement (PPA) which expired on December 31, 2025, the price from Centralia's coal is significantly higher than the wholesale energy market price, at $62.04 per MWh versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15 (Declaration of Callahan Moriyasu). It is also unclear whether Centralia will be safe to operate. Recent inspections and the most recent quarterly report indicate that Centralia's pollution control technology requires maintenance or repairs.

[4] *See e.g.* RCW 80.28.010(1) (The UTC is also tasked with regulating IOUs in the public interest and ensuring rates for "any service rendered" are "just, fair, reasonable, and sufficient."); The Clean Energy Transformation Act requires utilities to achieve targets at the "lowest reasonable cost," RCW 19.405.040(6)(a)(i), -.050(3)(a),-.060(1)(c)(ii), -.080(2)(b).

Ex. 11 at ¶ 10-11. Further, recent staffing shortages may have led to the violations that Centralia was noticed for in December. Ex. 11 at ¶ 12. TransAlta will likely have to expend resources to quickly hire and train new staff to operate the facility. As described below, TransAlta has sought to recover those costs from rates, which amount to tens of millions of dollars for the first 90-day period of Centralia I alone. By ordering the continued operation of TransAlta's Centralia Coal Plant, Centralia III ensures that Washington ratepayers will see unreasonably higher electricity bills, in contradiction with Washington's statutory mandate to secure rates that are "just, fair, reasonable, and sufficient." RCW 80.28.010(1).

IV. BACKGROUND

A. The Long-Planned Retirement of TransAlta's Coal-fired Units

1. The TransAlta Centralia coal-fired power plant

The Centralia generating plant is a coal-fired power plant located just east of Centralia in Lewis County, Washington that is owned and operated by TransAlta Generating LLC ("TransAlta Centralia" or "Centralia"). Centralia was built in the late 1960s and originally consisted of two coal-fired boilers. Ex. 15 (The Daily Chronicle, *Plant Job Underway*, June 14, 1968); Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). The first boiler went into operation in 1971 and the second in 1972. The first boiler, known as "Unit 1" was retired in 2020, and the second boiler, "Unit 2," was scheduled to retire by December 31, 2025. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). Centralia currently has a nameplate generating capacity of 729.9 MS and a net capacity of 670 MW. Ex. 18 at "Operating" tab, row 5359, plant name "TransAlta Centralia Gen LLC" (U.S.

Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860).

TransAlta Centralia generates electricity by combusting pulverized coal in a boiler to generate pressurized steam to drive a turbine. Ex. 17 at 2 (2021 Title V Air Operating Permit Basis Statement). This produces emissions of sulfur dioxide (SO2), oxides of nitrogen (NOx), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants including mercury. Ex. 17 at 2. TransAlta Centralia has been one the largest historical sources of NOx and SO_2 in Washington, annually emitting over 5,000 tons of NOx and 1,500 tons of SO2 in 2011–18. Ex. 19 at 74 (2022 Visibility SIP). Since closure of Unit 1 of Centralia in 2020, emissions have decreased by approximately half, but these emissions still rank amongst the highest in the State for a single source. Ex. 19 at 74. TransAlta Centralia is also the largest single stationary source of greenhouse gas emissions in the state with, over 3.9 million metric tons of annual CO2 emissions in 2022, and over 4.5 MMT CO2 in 2023. Ex. 12; Ex. 13. These pollutants have significant adverse health and environmental impacts. Ex. 10 at ¶¶ 7–14. TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural areas, including at Mount Rainer National Park, located only 50 miles from the plant. Ex. 19 at 172 (2021 Visibility SIP).

2. Agreement reached over a decade ago to transition TransAlta away from coal

In 2011, Washington, TransAlta, environmental groups, and the local community worked together to establish a plan to transition Centralia away from coal towards cleaner fuels. Ex 20 (TransAlta Power Plant, Department of Ecology). The Washington Legislature

passed the Coal-Fired Electric Generation Facilities Act, Engrossed Second Substitute S.B. 5769, Ch. 180, Wash. Laws of 2011, requiring TransAlta Centralia to comply with the state's greenhouse gas emission performance standards beginning at the end of 2020 for Unit 1 and the end of 2025 for Unit 2. Ch. 180, Wash. Laws of 2011 § 103; RCW 80.80.040(1), (3)(c). The Washington Department of Ecology then issued a Best Available Retrofit Technology (BART) order to TransAlta pursuant to its authority under the Washington Clean Air Act and the visibility and regional haze programs of the Federal Clean Air Act. The BART Order recognized that TransAlta Centralia would comply with the greenhouse gas emissions standards through the phased retirement of its coal-fired boilers. Ex. 7 at 2 §D(a). The BART order further specifically requires TransAlta to "permanently cease burning coal" and decommission both coal-fired units at the plant by 2025. Ex. 7 at 4, condition 4; Ex. 8 at 3, condition 3. By the end of 2011, the State and TransAlta signed a Memorandum of Agreement, as required by SB 5769, in which TransAlta formally agreed to the phased shutdown of both coal-fired boilers by the end of 2020 and 2025 respectively. Ex. 5 at 1 (Recital D) (TransAlta agreed to "permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025.").

In 2017, the MOA was amended to, among other things, change the scope of power generation activities that TransAlta Centralia was required to cease in 2020 and 2025. While the 2011 MOA originally requiring cessation of all "power generation operations" in the two boilers, the amendment signed in 2017 narrowed this to requiring cessation of only "*coal-fired* power generation operations" of each boiler. Ex. 6 at Section 1 (amending Subsection D(5) of the MOA). This would allow TransAlta to continue generating electricity at Centralia upon

the conversion of its boilers to cleaner fuels such as natural gas. Ecology's 2020 revision to TransAlta's BART Order reflected this, acknowledging the possibility of continued operation of the Centralia plant with cleaner fuels. Ex. 9 at 3 (2020 Bart Order TSD at 3) ("If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.").

3. TransAlta coal-to-gas conversion project

TransAlta has now developed a plan to convert TransAlta Centralia to natural gas.[5] On December 9, 2025, TransAlta announced a long-term agreement with Puget Sound Energy to perform a coal-to-gas conversion on Centralia's Unit 2 facility with a planned contracted capacity of 700 MW to deliver power to Puget Sound Energy ("PSE") through 2044. Ex. 20 at 1 (Press Release from TransAlta dated Dec 9, 2025,). TransAlta expects to invest approximately $600 million in capital expenditures in the project, and is targeting late-2028 to begin commercial operations, which will reduce emissions by approximately 50%. *Id*. TransAlta's President and Chief Executive Officer, John Kousinioris explained that TransAlta was "pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers." *Id*.

[5] The State cites to the announced conversion to natural gas in keeping with industry practice of including announced planned additions to generation. To finalize those plans, TransAlta will need numerous permits and approvals from the State for the conversion to occur. Nothing within this filing should be interpreted as any agency or arm of the State presupposing or otherwise commenting on the merits of those permits or approvals.

After conversion, TransAlta Centralia will operate only when there is high demand, with the majority of its hours of operation expected to be at half load (~350 MW) or at minimum stable generation load (~190 MW), but with the ability to quickly ramp up to high loads when needed by the grid. Ex. 21 at 1-1 (December 2025 TransAlta PSD Permit application). Conversion of Centralia to natural gas will dramatically reduce TransAlta Centralia's emissions of almost all pollutants, including large and fine particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), lead, and carbon dioxide (CO_2). Ex. 21 at 3–4 (Table 3-1).

B. Washington Recently Assessed and Confirmed Resource Adequacy in Our Region

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Indeed, in its July 2025 resource adequacy report, DOE wrote, "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level….entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience." Ex. 4 at i (DOE 2025 Resource Adequacy Report).

In this, DOE is correct, and Washington's Utilities and Transportation Commission does precisely that, and held three meetings in 2025 in conjunction with Washington's Department of Commerce to consider information from industry experts from Washington utilities, regional planning organizations, transmission operators, reliability experts, and the public. Ex. 53 ¶¶ 4-6 (Declaration of Brian Rybarik, Chair of the Washington Utilities and

Transportation Commission). As a matter of best practice, resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country. *See* Ex. 55 (*Best Practices in Integrated Resource Planning,* Synapse Energy Economics & Lawrence Berkeley National Laboratory (Nov. 2024). Following this best practice, the Washington Utilities and Transportation Commission, and the November 2025 Winter Readiness Resource Adequacy meeting, Washington planners invited presentations from National Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council, Arne Olson, the author of the E3 PowerPoint, as well as from Washington utilities. Ex. 22 (Nov. 19, 2025 Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting) (The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

By contrast, DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. And, as far as Washington can determine, DOE failed to attempt consultation with any of the local, regional, or national reliability experts in issuing its emergency order regarding TransAlta. Using the information from the entities responsible for maintenance and operation of the grid, in November 2025, Washington's utility regulators confirmed the adequacy of generation resources for our state's electricity grid. Ex. 22. In a letter summarizing the September meeting, Washington state utility regulators assessed resource adequacy as follows:

> Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a

> region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.
>
> However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

Ex. 22 at 1–2. Washington's utility planners also considered Washington's winter readiness, reporting that:

> Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Counsel, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions with winter. Extreme weather poses and elevate risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures for firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.
>
> At the November 4 Meeting, the Bonneville Power Administration and utilities shared steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sount Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

Ex. 50, ¶ 10 (Declaration of Andrew Reeves); Ex. 50-4 (Summary of 2025 Winter Preparedness Meeting). The Chair of the Washington Utilities and Transportation

Commission reviewed DOE's emergency order in light of his industry experience, his review of resource adequacy plans filed with the Commission, the information from national, and regional experts and concluded, "I do not find that DOE's Order's conclusions that an energy emergency exists in the coming winter months credible, nor do I agree that action under the DOE order (keeping the Centralia coal plant available) will assist in solving the unlikely extreme conditions that could lead to an energy emergency." Ex. 96 at 3.

Tellingly, DOE's flawed July 2025 Resource Adequacy Report found that even assuming all firm planned retirements, including TransAlta, and assuming minimal resource additions the Washington region faces no significant long term reliability risk:

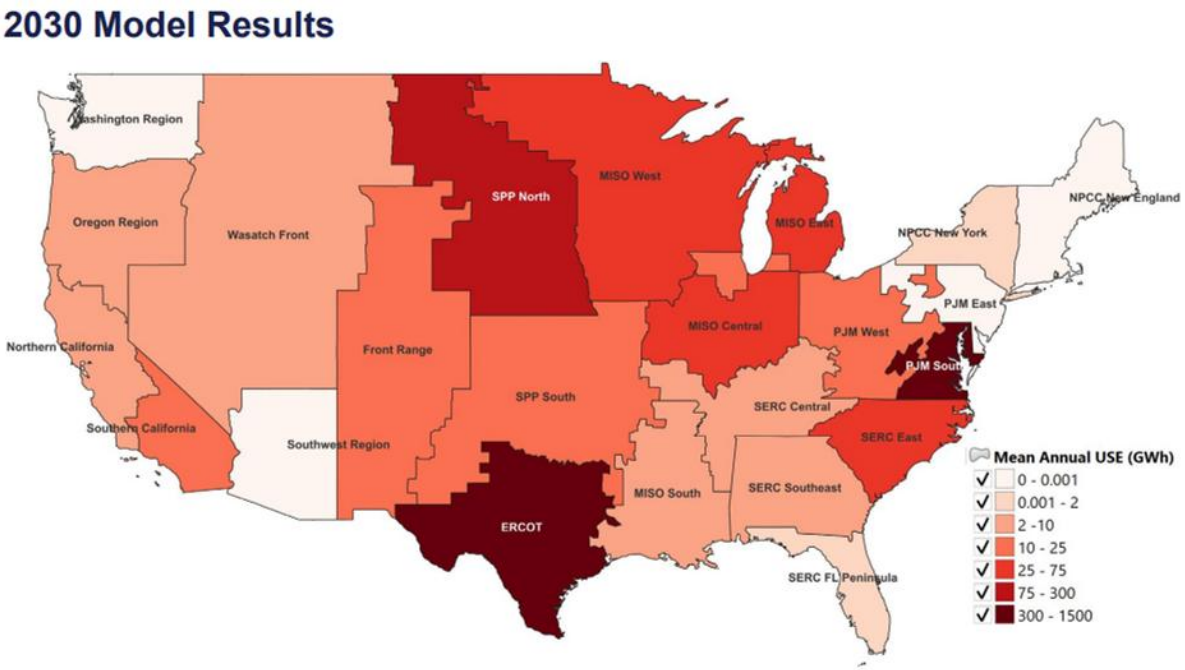


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Ex. 4 at 6 (DOE 2025 Resource Adequacy Report). The deep methodological flaws in DOE's report are discussed at greater length below. But for the purposes of this review, all information agrees; even under DOE's worst case scenario analysis, the Washington region is

one of the few regions in the country in which reliability is not a concern before 2030. The reality is that there is no reasonable dispute that there is no energy emergency in the Washington to justify an order to keep TransAlta available as a coal plant.

C. DOE's Historical Use of Section 202(c)

Prior to 2025, DOE has used section 202(c) sparingly, and only in response to concrete, particularized emergencies subject to limitations to ensure that DOE's reach extends no further than necessary to address the emergency at hand.

As discussed below, section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). The law also effectively immunizes noncompliance with "any Federal, State, or local environmental law or regulation" associated with an action or omission necessary to comply with a 202(c) order." 16 U.S.C. § 824a(c)(3). However, the Act also imposes significant limits on any 202(c) order that "may result in a conflict" with a pollution control requirement, including limiting the hours of operation of such facilities and limiting the order to 90-days, with extension possible. 16 U.S.C. § 824a(c)(2) and (4).

That authority originated as a wartime power granted in 1935 to what was then the Federal Power Commission in order to guard against energy-related shortages that were viewed as hampering national security during World War I. *See* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 798-802 (2025). The then-Federal Power Commission did not invoke its emergency authority until the United States entered World

War II. *See id.* at 803. Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. These "interconnection" orders between utilities were more necessary at a time when America's electric grid was more fragmented, monopolized, and less diversified than it is today. *Id.* at 802-804. Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time. *Id.* at 801-802. A number of organizational changes ensued in the decades following the War and the provision's authority eventually came to rest with the Secretary of Energy. *Id.* at 803-04; 42 U.S.C. § 7151(b).

DOE has historically invoked its 202(c) emergency sparingly to respond to clear-cut and imminent emergencies to avoid immediate significant blackouts. *See* Rolsma, *supra*, at 805-509. Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of 2024, DOE appears to have used section 202(c) twenty times, not counting amendments and extension orders, prior to 2025. *See* Ex. 23-1 through 23-20. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000. Ex. 23-1 (DOE, *Order Pursuant to Section 202(c) of the Federal Power Act*, December 14, 2000). Since then, by far the most common usage—comprising 14 of 20 instances—has been in response to extreme weather events such as hurricanes, extreme cold, and extreme heat. *See* Exs. 23-2 and 23-3 (DOE Order Nos. 202-05-1 & -2, September 28, 2005) (response to Hurricane Rita); Ex. 23-4 (DOE Order No. 202-08-1, September 14, 2008) (Hurricane Ike); Ex. 23-5 (DOE Order No. 202-20-1, August 27, 2020) (Hurricane Laura); Ex. 23-13 (DOE Order No. 202-24-1, October 9, 2024) (Hurricane Milton); *See* Ex. 23-7 (DOE Order No. 202-21-1,

February 14, 2021) (extreme cold); Ex. 23-11 (DOE Order No. 202-22-3 (December 23, 2022) (extreme cold); Ex. 23-12 (DOE Order No. 202-22-4, December 24, 2022) (extreme cold); Ex. 23-6 (DOE Order No. 202-20-2, September 6, 2020) (extreme heat in California); Ex. 23-8 (DOE Order No. 202-21-2, September 10, 2021) (extreme heat, wildfires and drought in California); Exs. 23-9, 23-10 (DOE Order Nos. 202-22-1 & 2, September 2022) (same).

In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both. And, in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements. DOE also limited the duration of those orders to the minimum period necessary to address the emergency, typically lasting for a period of days to weeks. *See* Rolsma, at 839-42 tbl.1 (chronicling all section 202(c) orders issued "after dissolution of the Federal Power Commission").

The typical process for issuing a section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes including demand response mechanisms are incapable of addressing, though they may be issued by DOE unprompted as well. *See* 10 C.F.R. § 205.370. Applications for section 202(c) orders made by outside entities are to include specific details to "be considered by DOE in determining that an emergency exists" and the appropriate intervention. 10 C.F.R. § 205.373. This includes "[d]aily peak load and energy requirements

for each of the past 30 days and projections for each day of the expected duration of the emergency," "[a] description of the situation and a discussion of why this is an emergency, . . . includ[ing] any contingency plan of the applicant and the current level of implementation," and "[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts." 10 C.F.R. §§ 205.373(a)-(o).

Prior to 2025, DOE has used section 202(c) on only three occasions to delay the retirement of generation facilities[6]. These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close. Ex. 23-1 at 1 (DOE Order No. 202-05-3, December 20, 2005) (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease

[6] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.

operations on August 24). The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[7] *Id*. at 2. Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C. *Id*. at 3–4. Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility. *Id*. at 5–8. The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service. *Id*. at 10–11.

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from ENERGY. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of

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[7] This incident eventually led to the statute's 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a section 202(c) order, leading the statute to read as it does today. *See* Rolsma, *supra*, at 806-08 (citing DEP'T OF ENERGY, ORDER NO. 202-05-3, December 20, 2005); 16 U.S.C. § 824a(c)(3)-(5).

the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair. And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials. Ex. 24 (Letter Request of Grand River Dam Authority). The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first. Ex. 23-15 at 2 (DOE Order No. 202-17-1). The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes." *Id*.

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond. Ex. 23-16 at 1 (DOE Order No. 202-17-2). DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes." *Id*. at 2. DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order. Ex. 23-17 at Summary of Findings (DOE Order No. 202-17-4, Sept. 14, 2017). In its extension order, the Department continued to limit dispatch of the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand

response and behind-the-meter generation resources, prior to operating the units. Ex. 23-17 at 2 (DOE Order No. 202-17-4, September 14, 2017).

D. White House Strategy to Prop Up the Coal Industry

Since the 2025 Inauguration, the White House and DOE have sought to radically transform how section 202(c) of the Federal Power Act is applied—departing in almost every material respect from the longstanding approach described above. On January 20, 2025, his first day in office, President Trump issued Executive Order 14156, titled "Declaring a National Energy Emergency." 90 Fed. Reg. 8433. That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.[8] *See Id*. (providing no factual support for claimed emergency).

On April 8, 2025, President Trump issued Executive Order 14262, titled "*Strengthening the Reliability and Security of the United States Electric Grid*." 90 Fed. Reg. 15521 (April 14, 2025). The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective. Ex. 56 (New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*, April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21,

[8] That declaration is subject to a pending legal challenge by multiple states. *See* Complaint, *Washington v. Trump*, NO. 2:25-cv-00869 (W.D. WA May 9, 2025).

2025). This event, and the related Executive Orders, are part of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure." Executive Order 14262 at section 3(a). It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- of a process by which the developed methodology and any analysis results are regularly assessed; and,
- of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.

Executive Order 14262 section 3(b), (c).

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14156, *Declaring a National Energy Emergency*. Executive Order 14262, § 2. In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. President Trump has declared eight national emergencies in the first seven months of 2025 alone, and

has invoked this power more in the first 100 days in office than any other President in modern history. *See* Ex. 57 (Brennan Center for Justice, *Declared National Emergencies Under the National Emergencies Act*).

E. DOE's Section 202(c) Orders Preventing the Retirement of Fossil Fuel Power Plants Issued in 2025

Since January 20, 2025, DOE has issued orders to eight facilities under section 202(c) of the Federal Power Act, a sharp uptick from the less than one order per year issued on average from 2017-2024. *See* Ex. 23 (2025 DOE 202(c) orders). In late May 2025 DOE issued a pair of section 202(c) orders requiring fossil fuel generation facilities in Michigan and Pennsylvania that were each slated to retire the very next business day to remain on-line. Ex. 27 (U.S. Dep't of Energy, Order No. 202-25-3 (Campbell Order); *See* Ex. 28 (U.S. Dep't of Energy, Order No. 202-25-4 (Eddystone Order). Both the Campbell and Eddystone Orders have now been extended twice. Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025). These orders represent a marked shift in how section 202(c) has historically been used.

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any imminent emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy's service territory, where decommissioning costs were already being recovered

through base rates. One Michigan regulator estimated that the costs of complying with DOE's order for 90 days would approach $100 million. *See, e.g.*, Ex. 29 (Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025). Consumers Energy disclosed that continued operation of the plant in the first five weeks since the Order was issued resulted in a net financial impact of $29 million. *See* Ex. 30 (CMS Energy Corp., Quarterly Report (Form 10-Q), July 31, 2025); *See also* Ex. 31 (NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target*, June 16, 2025).

F. DOE Publishes Its Methodology and Reliability Standard to Guide Future Section 202(c) "Reliability Interventions"

On July 7, 2025, DOE published its "Report on Evaluating U.S. Grid Reliability and Security," which set forth the methodology and reliability standard that the Executive Order on grid reliability had mandated. Ex. 4 (U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, July 2025). DOE published this report without proving any public notice or comment period and without any apparent consultation with any grid operator or State. *See* Ex. 4 at i (acknowledging lack of data from regional and utility levels). Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE's analysis. Nor has DOE opened any administrative proceeding to otherwise involve the public in DOE's methodology and DOE has not published the Report in the Federal Register.

Nevertheless, DOE confirmed in the report that it would rely on the Resource Adequacy Report to justify future section 202(c) orders, consistent with the Executive Order's mandate. *See* Ex. 4 at vi (explaining that DOE's standard will be used to "guide reliability

interventions"); *id.* at 1 (emphasizing the need for DOE's "decisive intervention" in energy markets); *id*. at 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT"). As explained in an accompanying fact sheet, DOE would use the methodology to "prevent [] generation resources from leaving the bulk-power system." Ex. 32 (U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid*, 2025); *see also* Ex. 33 (Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security, July 7, 2025) (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act").

Due to numerous significant flaws in DOE's resource adequacy report that render it arbitrary and capricious, a number of states including Washington submitted a rehearing request to DOE on August 6, 2025. Ex. 35 (August 6, 2025 Rehearing Request). Among other things, the rehearing request pointed out that the Report was based on flawed and arbitrary assumptions and unsupported by substantial evidence because it failed to reasonably support its load growth assumptions and arbitrarily assumed 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same period, lacked sufficient regional granularity and suffered from other analytical flaws, and established an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act. *Id*. at 18–29. In addition, the report does not point to any sudden, unforeseen, or imminent circumstances that describe an "emergency" under the Federal Power Act to justify 202(c) orders, the report fails to consider existing reliability mechanisms, intrudes on state authority

over generation facilities and non-emergency resource adequacy planning, and was adopted subject to critical procedural flaws including failing to provide public notice and comment. *Id*. at 29–39.

DOE did not respond to the critiques raised by the States and other entities of its resource adequacy report and continues to rely on the resource adequacy report to justify emergency 202(c) orders. Rather, DOE denied the States' and other entities' requests for rehearing based on its assertion that the resource adequacy report was not an "'order' by which the State AGs are 'aggrieved' within the meaning of section 313 of the FPA." 313*l*. Ex. 35-2 (2025 State AG's Request for Rehearing of DOE Report).

G. DOE's 202(c) Emergency Order to TransAlta Requiring It To Continue To Be Available as a Coal-Fired Power Plant

On December 16, 2025, DOE issued a 202(c) order to TransAlta, requiring that Centralia remain ready to run as a coal-fired power plant beyond its scheduled closure date of December 31, 2025. Ex. 1. This Order, issued only 15 days before Centralia's scheduled closure as a coal plant, directed TransAlta to "take all measures necessary to ensure that Centralia Unit 2 is available to operate" at the direction of either the Balancing Authority or Reliability Coordinators for the region—which the Order identified as Bonneville Power Administration (BPA) and the California Independent System Operator Corporation (CAISO), respectively. Ex. 1 at 3. On March 13, 2026, DOE amended the Order, via Order No. 202-25-11B, identifying the Balancing Authority and Reliability Coordinator as Gridforce and SPP. While this suggests that the plant should be kept on standby at the ready to run as needed, the Order also confusingly stated in footnote 11 that "continuous operation is required . . . so long as Secretary determines a shortage exists and is likely to persist," to

avoid the complications that could result from starting and stopping operations intermittently. Ex. 1 at 2, n. 11.

The order justifies DOE's invocation of its emergency authority under section 202(c) of the Federal Power Act due to the Secretary's determination of an "emergency situation" within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]" Ex. 1 at 1. Specifically, DOE's determination of an "emergency" is based on the NERC's 2025-2026 Winter Reliability Assessment, a September 2025 Power Point presentation on resource adequacy by Energy + Environmental Economics (E3), and DOE's July 2025 Resource Adequacy Report and two executive orders. *Id*. While the Order acknowledged that these sources found that "there is sufficient capacity for expected peak conditions," DOE asserted that there was a present emergency anyway due to an "elevated risk during periods of extreme weather." *Id*. That "elevated risk" contemplates a scenario in which, during a period of peak demand, extreme weather causes the outage of thermal power plants as well as adverse wind turbine conditions and, on top of that, similar extreme weather extends to neighboring regions so that the Northwest Region cannot import power. *Id*. The Order also cited accelerated load growth estimates out to 2030 and a shortfall in the development of adequate new capacity to meet this forecast demand. *Id* .

Finally, the Order cited the president's Executive Orders declaring a national energy emergency and on grid reliability for additional support and cited DOE's July 2025 resource adequacy report conducted under those executive orders for the proposition that "decisive intervention" to the Nation's power grid was necessary "to meet projected demand for

manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation." Ex. 1 at 2-3 (citing Ex. 4).

H. Impacts of Continued Coal Operations at Centralia

1. Deferred maintenance and upgrades make running Centralia as a coal plant difficult, expensive, and less reliable

TransAlta Centralia is an old facility and has not been maintained for continued operations beyond 2025 due to its planned retirement. Moreover, in recent years Centralia has been subject to frequent forced shutdowns due to breakdowns. For example, from 2023 through 2025 Centralia shutdown 29 times, 25 of which were forced outages, for issues such as needed "tube leak repairs." Ex. 11 at ¶ 7; Exs. 11-1 through 11-11 (Centralia Plant's quarterly reports submitted to SWCCA from 2023 through 2025).

Centralia's electrostatic precipitators (ESPs) that control its coal fly ash particulate matter emissions are failing—causing the plant's plume to register opacity levels approaching its 30% permit limit, even when operating below full load. Ex. 11 at ¶¶ 9–10; Ex. 11-12 (photograph of opacity readings on Oct. 23, 2025). In addition, Centralia has not been able to maintain the required control of its carbon monoxide (CO) emissions. Ex. 11 at ¶ 11; Ex. 11-3 (TransAlta Most Recent Quarterly Report). As described by TransAlta in its 2022 U2 Boiler Tune-up Report, this could be due to air leakage associated with cracks and holes that is impairing operation of fan components. Ex. 11 at ¶ 11; Ex. 11-13 (Centralia Plant's 2022 U2 Boiler Tune-up Report).

Skeleton crew staffing has and will further exacerbate the plant's proper functioning. For example, TransAlta's local air regulator, which conducts regular inspections, issued it two Notices of Violation in December 2025 for issues that may have been related to reduced

staffing and/or maintenance. Ex. 11 at ¶ 12. The first was related to excess emissions from the fly ash unloading baghouse and the second was for not fully engaging all relevant pollution control equipment prior to firing coal on startups. Exs. 11-14, 11-15 (SWCAA Notices of Violation No. 10642 and No. 10643).

TransAlta Centralia's coal-fired power also costs more, so ratepayers are likely to pay higher electricity bills to the extent there are continued coal-fired operations. Centralia power is priced significantly higher than the wholesale energy market price: $62.04 per MWh for Centralia versus the wholesale market price of $54.32 per MWh. Ex. 41 at ¶ 15.

And DOE's order disrupts plans to strengthen reliability by converting Centralia to natural gas. As discussed above, TransAlta has announced plans and submitted permit applications to convert its plant from coal to natural gas in order to operate as a peaking plant under a commercial agreement with Puget Sound Energy. This conversion is in danger of being disrupted and delayed by DOE's order to continue operating Centralia as a coal plant. The risk of delay will compound over time if DOE continues to extend its Order repeatedly, as it has done for other plants such as the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania.[9] DOE's interference thus harms the ability of utilities to take steps they see as necessary to improve reliability—TransAlta Centralia as a natural gas peaker plant will provide grid services that an outdated coal plant cannot. Ex. 49 at ¶¶ 5–7 (Declaration of David Gomez).

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[9] *See* Ex. 58 (Campbell Order First Extension, DOE No. 202-25-7, August 20, 2025); Ex. 36 (Campbell Order, Second Extension, DOE No. 202-25-9, November 18, 2025); Ex. 59 (Eddystone Order, First Extension, DOE No. 202-25-8, August 28, 2025); Ex. 63 (Eddystone Order, Second Extension, DOE No. 202-25-10, November 25, 2025).

2. Running Centralia results in health and environmental impacts

Continuing coal operations at Centralia will increase air pollution in Washington, harm Washingtonian's health (imposing direct harms on the State and its agencies), and impair visibility at Washington's iconic natural areas such as the Mount Rainer National Park. *See supra* pp. 13–18; *see also* Ex. 10. Centralia has been a significant source of air pollution in Washington including for particulate matter, sulfur dioxide, nitrogen oxides, dioxin and furans, mercury, heavy metals, and polycyclic aromatic hydrocarbons. Ex. 10 at ¶ 7; Ex. 52 at ¶ 8.

Those emissions are known to adversely impact human health. For example, dioxins and furans are highly toxic persistent environmental pollutants that can cause cancer, reproductive and developmental problems, damage to the immune system, and hormone disruption. Ex. 52 at ¶ 11. Mercury exposure poses especially significant health risks for pregnant women and infants because of its impacts on fetal development and infant health. *Id*.; Ex. 10 at ¶ 14. Polycyclic aromatic hydrocarbons (PAHs) cause a range of serious health risks including various cancers, respiratory and cardiovascular diseases, and reproductive health problems. Ex. 52 at ¶ 11.

A series of investigations at Centralia found six hazardous substances in the soil, nine contaminants for groundwater, and nine substances in the sediment at the Site above cleanup levels. *Id.* at ¶ 7. Continued aerial emissions of hazardous substances associated with TransAlta's coal operations have the potential to settle on and contaminate thousands of properties and create thousands of PLPs. *Id.* at ¶ 14. And the Centralia Coal Plant uses settling

ponds containing byproducts from burning coal, many of which are also hazardous substances subject to MTCA. *Id.* at ¶ 15.

Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the continued operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million annually in Washington. Ex. 10 at ¶ 10. Moreover, even after the plant is converted to natural gas and begins operating again in 2028, the cleaner performance of the natural gas plant compared to coal-fired operations is expected to prevent an estimated 4–7 premature deaths, 2 nonfatal heart attacks, 24 cases of asthma onset, with an economic value of $68-110 million annually in Washington. Ex. 10 at ¶ 12. Children are acutely prone to these health risks because their bodies are still developing, and they have more exposure to airborne contaminants that settle on lawns, parks, and schoolyards. Ex. 52 at ¶ 10.

These health impact estimates are based on the assumption that Centralia continues to abide by the requirements of its environmental permits. Ex. 10 at ¶ 7. However, Centralia's most recent quarterly report and recent inspections of the facility indicate that maintenance on Centralia's pollution control equipment is due or overdue. Ex. 11 at ¶¶ 10–11. A local clean air agency also issued Centralia two notices of violation for exceeding emissions limits in December 2025. *Id*. at ¶ 12; Ex. 11-14 and Ex. 11-15. Therefore, emissions under emergency coal-fired operations may be even higher if TransAlta Centralia cannot operate at a lower load or make necessary repairs. *Id*. at ¶ 11.

In addition to these health impacts, TransAlta Centralia's emissions of particulate matter, SO_2, and nitrogen oxides (NOx) also impair visibility in Washington's iconic natural

areas, including at Mount Rainer National Park, located only 50 miles from the plant. And, because Centralia is the largest source of greenhouse gas emissions in Washington, Ex. 12, the continued coal-fired operations will also make it harder for Washington to achieve its statutory greenhouse gas emissions reduction requirements. *See* RCW 70A.45.020.

I. DOE's Section 202(c) Order Renewals

Since the sharp uptick in DOE's section 202(c) orders that started last year, DOE has issued at least 16 total extensions to six coal facilities. In August 2025, one day before the first order was set to expire, DOE issued a second section 202(c) order requiring the Campbell coal plant in Michigan to remain on-line. Ex. 58. DOE extended the order again in November 2025, a third time in February 2026, and a fourth time in May 2026. Ex. 36, Ex 101, Ex. 121 (May Campbell Order). Similarly, DOE extended its original May 2025 order issued to the Eddystone Generating Station in Pennsylvania in August 2025, November 2025, February 2026, and May 2026. Ex. 28, Ex. 59, Ex. 63, and Ex. 102, Ex. 122 (May Eddystone Order). After the initial order in December 2025, DOE issued two renewal orders to the Craig Station coal facility in Colorado. Ex. 123 (December Craig Order), Ex. 124 (March Craig Order), Ex. 125 (June Craig Order). DOE also issued two renewal orders to both the F.B. Culley Generating Station and the Schahfer Generation Station coal plants in Indiana after their initial orders in December 2025. Ex. 132 (December Culley Order), Ex. 126 (March Culley Order), Ex. 127 (June Culley Order), Ex. 128 (December Schahfer Order), Ex. 129 (March Schahfer Order), Ex 130 (June Schahfer Order). Across the country, DOE has demonstrated its commitment to keeping coal plants available to operate by seemingly finding "emergency conditions" that extend beyond a year in the case of Campbell and Eddystone.

DOE issued a renewal order for Centralia on March 16, 2026. Ex. 100. It issued a subsequent renewal order for Centralia on June 12, 2026. Ex. 120. In addition to repeating its speculative claims about "periods of extreme weather" and potential long-term grid capacity issues, in its latest renewal order, DOE cited to NERC's 2026 Summer Reliability Assessment, an amended preliminary injunction issued by the District Court for the District of Oregon, and a Presidential Memorandum concerning the Defense Production Act to support the renewal of the Order. *Id.*

DOE's renewal order will exacerbate problems with Washington's grid by slowing the Centralia plant's conversion to natural gas. For example, TransAlta cannot demolish the existing cooling towers, a necessary step in the conversion process, if it's required to remain available to operate. Ex. 103at ¶ 6 (Second Lamoreaux Decl.); Ex. 103-1 (Air Discharge Permit Application). The first and second order also proved unnecessary—TransAlta was never needed or called on to operate during these first two emergency orders, even during a six-day outage by the largest non-hydroelectric generating facility in the state. Ex. 104 at ¶ 3, 6 (Second Moriyasu Decl.); Ex. 131 (Third Moriyasu Decl.) at ¶ 21.

J. TransAlta Applied for Permits for Its Planned Natural Gas Conversion

Prior to DOE's December section 202(c) order, TransAlta targeted late 2028 to begin commercial operations at the natural gas facility conversion that would replace its coal facility. Ex. 41 at ¶ 6. The December 202(c) order required TransAlta to "take all measures necessary to ensure that Centralia Unit 2 is available to operate . . ." Ex. 1 at 3. That effectively delayed, or at least made uncertain, TransAlta's natural gas conversion. Although TransAlta is still

taking steps to move forward with the planned conversion, further 202(c) orders could significantly delay that process.

One of the first steps in the planned conversion is to obtain the necessary environmental permits. The Department of Ecology issues Prevention of Significant Deterioration (PSD) permits for major modifications to existing sources that will trigger an increase in certain air emissions. TransAlta needs the PSD permit prior to beginning actual construction of the natural gas plant. TransAlta submitted its PSD permit application to Ecology on December 24, 2025. Ex. 105 at ¶ 6 (Lim Decl.); Ex. 105-1 (TransAlta PSD Permit Application). On January 23, 2026, Ecology sought more information from TransAlta, and on March 10, 2026 TransAlta responded with the requested information, which Ecology is still evaluating. Ex. 105-1 at ¶¶ 7–8; Ex. 105-2 (Ecology Incompleteness Letter); Ex. 105-3 (TransAlta Incompleteness Letter Response).

TransAlta has also submitted its Air Discharge Permit Application to the Southwest Clean Air Agency (SWCAA) in preparation for its planned conversion. The Air Discharge Permit is also a prerequisite to construction. Ex. 103 at ¶ 6.

TransAlta's Air Discharge Permit application indicates that it will replace the existing cooling towers with new units. Ex. 103-1. Although TransAlta needs to obtain air quality permits to begin construction, it does not need permits to begin the demolition process of those existing cooling towers or other activities that are not considered construction. Once TransAlta receives its necessary permits, which Ecology and SWCAA both anticipate occurring by late summer or early fall 2026, TransAlta can commence actual construction of the natural gas facility. Ex. 103 at ¶ 8; Ex. 105 at ¶ 9 (Lim Decl.) (Ecology is the lead SEPA

agency and anticipates that the SEPA process will be completed before the PSD permit is issued). However, TransAlta will not be able to undertake demolition and other pre-construction activities, or commence construction of the natural gas facility, if DOE continues to issue 202(c) orders.

K. Columbia Generating Station Outage

Washington's largest non-hydroelectric generating facility is the Columbia Generating Station (CGS) nuclear power facility. Ex. 104 at ¶ 3. An unplanned outage at CGS can result in a significant loss of generation capacity in Washington. CGS produces ten percent of the energy produced by the Total Electric Power Industry in the state—enough to power one million homes. *Id.* However, in the event of an unplanned outage at CGS, or any other generating facility in Washington, other facilities ramp up their generation to compensate for that loss and keep the grid functioning at capacity.

That scenario played out in February of 2026, when CGS experienced an unplanned outage due to an issue with the cooling system that supports the reactor's recirculation pumps. *Id.* at ¶ 4. At 2:49 a.m. on February 12, the nuclear plant unexpectedly shut down. *Id*. CGS alerted the Nuclear Regulatory Commission of the outage by 9:25 a.m. *Id.* CGS did not come back online until February 18. *Id.*

Despite the six-day outage, there were no blackouts during the period that CGS was offline. In fact, BPA maintained net generation greater than net demand during the entire duration of the outage. *Id.* at ¶ 6. The gap in supply was primarily filled by hydro and wind resources. *Id.* at Figure 1 (Hourly Generation Mix in BPA Balancing Authority).

During Centralia I, TransAlta Centralia's coal-fired power was not once needed or used to balance the grid or serve load. Although Centralia was available to operate as a result of the first order, and the grid experienced a 10% loss of total supply as a result of the CGS outage, Centralia power was not necessary during the six-day CGS outage. *Id.* at 6.

Similarly, TransAlta has not been needed at any point during Centralia II. Ex. 131 at ¶ 21.

L. NERC's 2026 Summer Reliability Assessment Continues to Confirm Resource Adequacy in Our Region Despite Methodological Flaws

The third Centralia order cites the NERC Summer Reliability Assessment (SRA) under the 'emergency situation' section, despite NERC categorizing the WECC-NW region as elevated, not high. *See* Ex 131-1 (2026 SRA). The 2026 SRA by NERC highlights "*potential* operational concerns that *may* need to be addressed" and does not support emergency action. Ex 131-1 at 1 (emphasis added). NERC defines *elevated risk* as "potential for insufficient operating reserves in above-normal conditions" whereas *high risk* is defined as "potential for insufficient operating reserve in normal conditions." Ex. 131-1 at 3. Under these criteria, WECC-NW does not meet the conditions to be classified as high risk.

Elevated risk represents "probabilistic categories [that] are low" under "extreme peak-day demand" or "extreme outage" scenarios (e.g., LOLH above 0.1 hours across the season). *Id*. at 10. However, NERC's criteria under the probabilistic index benchmark differs from more standardized criteria used by FERC, arbitrarily elevating perceived risk by up to 5%. Ex. 131 at ¶ 4. Even under NERC's "most severe operating conditions of an area's summer risk scenario," which would not occur until August, or more likely September, WECC-NW maintains a projected 8.8% margin, never falling below demand. Ex. 131-1at 10–11, 36.

NERC's projections for demand growth and resource limitations are overstated. WECC-NW's anticipated reserve margins dropped by 5% this year, which NERC still assesses as adequate for normal summer peak load conditions. Ex. 131-1 at 2. This slightly tighter margin is due to NERC's projected demand growth of 4.6% over last summer's forecasts, while anticipated resource growth is at 1.5%. Ex 131-1 at 36. DOE relies on NERC's assessments attributing increased demand principally to data centers, both nationally and in the WECC-NW region. Ex. 131-1 at 8; Ex 106 at 19; Ex. 120 at 4. NERC's assessments do not account for redundancy when data centers enter multiple interconnection queues, global supply chain issues, and regulatory barriers that can lead to significant overestimation of demand. Ex. 131 at ¶ 8. DOE also relies on E3's Resource Adequacy Study, which, similar to NERC, fails to account for large load flexibility and overstates the risk to resource adequacy. Ex. 131 at ¶ 14–16. The WECC-NW region—which has lower concentrations of data centers than most other regions to begin with—has waning data center plans from IOUs and a flurry of data center moratoriums throughout the region. Ex. 131 at ¶ 10–13. Notably, NERC's extreme demand projections from 2025 were never reached. Ex. 131-1 at 54.

According to NERC, WECC-NW's classification as elevated is attributable to the potential for heat events, wildfires, and low snowpack. Ex. 131-1 at 36. However, state regulators and investor-owned utilities convening on resource adequacy concerns in June 2026 confirmed that low snowpack is "partly offset by above average snowpack and reservoir levels in the Upper Columbia basin in British Columbia" leading to higher hydropower projections for the region than last year. Ex. 131 at ¶ 4. Further, NERC's LTRA

excludes generation sources that are near completion, non-firm imports, and potential new transmission, all of which underestimate future capacity. Ex. 131 at ¶ 7–8.

NERC also changed its assessment methodology this year, inexplicably decreasing demand response from 30 MW to 2 MW between the 2025 and 2026 SRAs which could account for the increased expected unserved energy. Ex. 131 at ¶ 3. Adding to the confusion, NERC notes that additional resources like those targeted by DOE's 202(c) orders have potential use principally during winter. Ex 131-1 at 9. Even DOE acknowledges this in its latest order, noting that thermal generators—like coal plants—can be a useful resource in the winter, while NERC classifies WECC-NW as a winter peaking region. Ex. 120 at 5; Ex 131-1 at 36.

In response to potential shortfalls, NERC recommends engaging state regulators to prepare for efficient management of demand. Ex. 131-1 at 6. The Washington State Utilities and Transportation Commission (WUTC) did just that in a June 22, 2026, Resource Adequacy Meeting with all of the state's Electric IOUs. Ex. 131 at ¶ 17. At that meeting, each utility independently confirmed adequate capacity for summer 2026, noting increased capacity, battery storage, and new access to electricity market resources. Ex. 131 at ¶ 18–20. Further, two of the state's largest IOUs confirmed no plans, or even canceled plans for data center connections. Ex. 131 at ¶ 9–10.

Ultimately, the NERC report, despite its methodological flaws, still confirms that the Washington region faces no significant reliability risk, and that there is no emergency in Washington or the greater Northwest region justifying DOE's invocation of section 202(c) authority. Washington regulators and utilities confirmed the same.

M. TransAlta Recently Sought Recovery for the Costs of DOE's First Section 202(c) Order via a Tariff Revision Filed with FERC

Each of DOE's Section 202(c) orders instructed TransAlta to seek recovery of costs incurred as a result of the orders via a tariff revision or waiver filed with the Federal Energy Regulatory Commission (FERC). Indeed, the most recent order stated that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)." Ex. 120 at 10.

TransAlta has now done just that. On April 30, TransAlta sought recovery for the costs associated with keeping Centralia available to operate from December 16, 2025 to March 16, 2026. *See* Application for Cost Recovery Under 16 U.S.C. § 824a(c), Docket No. ER26-2422-000 (April 30, 2026) ["Application for Cost Recovery"]. TransAlta is seeking $19,862,266.65 for general operating, maintenance, and administrative costs, even though Centralia was never directed to operate during that period. *Id.* at 8–9. As described more fully in the argument below, these costs will continue to accrue for each new section 202(c) order DOE issues and will ultimately be paid for by consumers.

V. REQUEST FOR REHEARING

In addition to the grounds laid out in Washington's request for rehearing in Centralia I and Centralia II, fully incorporated as set out herein, Washington provides the following additional grounds for rehearing of Centralia III.

A. The NERC 2026 Summer Reliability Assessment Still Does Not Establish an Emergency

The SRA does not establish an emergency. DOE's Order based on conditions "from increasing demand" "in the near term" and "subsequent years" leading to "potential loss of power" is based entirely on circumstances that have yet to—and may never—materialize.

Ex. 120 at 8. Risk of potential loss of power at an unspecified time in the non-immediate future is not an emergency. This disregards NERC's own definition of elevated risk and the steps it recommends in response, as well as the Federal Power Act's description of emergency.[10]

As with the Winter Assessment, the description of the WECC-NW at an "elevated" risk for power shortages under "extreme" conditions, and as set out in Washington's request for rehearing of Centralia I and II, the Summer Assessment fails to support a conclusion that there is an "emergency" within the meaning of section 202(c). Again, NERC's criteria for "elevated risk," a step below the "high" risk category, is not a forecast of an imminent emergency.

While the NERC 2025–2026 Winter Reliability Assessment was not cited in Centralia II's "emergency situation" section, DOE now uses the Summer Assessment as evidence of an emergency. DOE's reliance on NERC's "elevated risk" designation fails to consider the meaning of elevated risk. This partly explains why Centralia was not required to run for the entire duration of Centralia I and Centralia II.

NERC places WECC-NW in the elevated category principally due to the remote prospect of extreme conditions in late summer—not because the entire summer represents a time of elevated risk. If an energy shortage were to arise based on the overlapping combination of multiple remote occurrences it would not be several months. An elevated risk in the NERC Summer Assessment does not indicate imminent risk of blackouts or power failures. It

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[10] 16 U.S. Code § 824a(c)(1) ("[S]udden increase in the demand for electric energy, or a shortage of electric energy or of facilities.")

represents the risk or possibility that regulators may deploy existing mitigation measures. Ex. 131-1 at 6.

A slightly lower reserve margin is not an electricity shortage—by definition there is still a substantial reserve margin. The idea that a reserve margin may become lower if there are outages or derates simply means the reserve margin is serving its intended purpose—to provide backup power in the event of an outage. Even if the most extreme conditions under NERC's assessment did arise in September, it would not constitute an emergency. Demand would never exceed capacity. If necessary, state regulators would implement measures to reduce demand, as suggested by NERC and as has been contemplated and planned for by the WUTC—neither of which recommend refiring an aged coal plant.

The Federal Power Act does not permit the issuance of emergency orders based on prospective events that could occur several months in the future under extreme, low probability scenarios. Here, DOE uses the extremely unlikely possibility of low reserve margins in August or September to issue an emergency order, months earlier, in June. And the most extreme scenario, leading to WECC-NW's classification as elevated, would not occur until August, or more likely September. Ex 131-1 at 36.

As detailed in Washington's second rehearing request, NERC's information sources are also seriously flawed. Centralia II Rehearing Request. NERC primarily relies on utility projections, although those forecasts are variable and uncertain. The flawed methods used by NERC continue to be demonstrated by reports and regulators now. Ex. 131 ¶ 7–8.

Potential loads from data centers further complicate the picture. As NERC acknowledges, large loads "inherently add volatility to load forecasts as project timelines and

commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions." Ex. 106 at 9. This very prediction has come true for the WECC-NW region since Centralia II was issued. Major IOUs are scaling back plans for data centers while cities and counties putting restrictions or outright bans on their construction. Ex. 131 at ¶ 10–13.

Ultimately, DOE relies on flawed data that—even when taken as true on its face—fails to establish an emergency.

B. TransAlta's Application for Cost Recovery and the Comments of BPA, CAISO, Gridforce, and SPP Show that DOE's Order is Arbitrary and Capricious, and Will Harm Ratepayers

As Washington argued in its prior rehearing requests, Centralia III will increase electricity rates for consumers, without providing any benefit. *See* Centralia I Rehearing Request at 93–94. In its Orders, DOE directed TransAlta to file tariff revisions or waivers with FERC to recover the costs associated with the Orders. In the event of a 202(c) order, FERC "may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party." 16 U.S.C. § 842a(c)(1). Here, requiring consumers to pay for TransAlta's efforts to keep Centralia online, in the absence of an emergency, is not reasonable.

Nonetheless, as discussed above, on April 30, 2026, TransAlta filed an application for cost recovery under 16 U.S.C. § 824a(c) with FERC. TransAlta sought $19,862,266.65 in "fixed costs" for "general operating, maintenance and administration costs that do not vary with the operating level of Centralia Unit 2." Application for Cost Recovery at 8–9. It also sought (1) variable charges of $35.90 per MWh, (2) environmental charges of $77.49 per

MWh, (3) start-up costs of $577,377 per start, and (4) any other costs FERC deems appropriate to operate Centralia as directed by the Order. *Id.* at 9–11.

DOE's emergency orders come at a cost, and that cost will be borne initially by the Balancing Authorities and Reliability Coordinators that DOE identified in its Orders. In its application for cost recovery, TransAlta sought compensation from the BPA, CAISO, Gridforce, and SPP, identified as the Balancing Authorities and Reliability Coordinators in DOE's first two Orders. In essence, FERC will then decide whether to require BPA, CAISO, Gridforce, and SPP to pay for plant operations that they did not need—and, according to BPA and CAISO, could not have utilized even if they did need power from Centralia. *See* Comments of the Bonneville Power Administration, Docket No. ER26-2422-000 (June 22, 2026) ["Comments of BPA"]; Protest of California Independent System Operator Corporation, Docket No. ER 26-2422-000 (May 21, 2026) ["Protest of CAISO"]. Even the proper Balancing Authority (Gridforce) and Reliability Coordinator (SPP) protest TransAlta's request to compensate it for costs incurred as part of the emergency order in this case. DOE's order to TransAlta to keep Centralia ready to operate since December 2025 has impacted many entities, none of which have benefitted from the emergency order or directed TransAlta to operate.

BPA and CAISO's arguments make clear that neither entity ever had an association with TransAlta and never had the authority to order dispatch of Centralia or purchase power from the plant. Comments of BPA at 3; Protest of CAISO at 1, 4, 8. It would be an injustice to the utility and residential customers of BPA and CAISO to require them to pay for a service

that they never could have even utilized, yet that is precisely what DOE's unlawful, arbitrary, and unjustified orders direct.

The protests of Gridforce and SPP also show that DOE's use of its section 202(c) authority was arbitrary because there were no beneficiaries from TransAlta keeping Centralia ready to operate as a coal plant. Those protests largely centered around the fact that neither entity was "a beneficiary of the Department's orders *or even capable of performing the functions referenced therein*." Protest of Gridforce Energy Management, LLC, Docket No. ER 26-2422-000 at 5 (May 21, 2026) ["Protest of Gridforce"] (emphasis added); *See also* Protest of Southwest Power Pool, Inc., Docket No. ER 26-2422-000 at 9 (May 21, 2026) ["Protest of SPP"]. Even though SPP could direct Centralia to generate electricity if needed for reliability, it claimed that requiring Reliability Coordinators to pay such costs would be unjust because it has no ability to recover costs associated with the generation of electricity at Centralia. Protest of SPP at 12. Gridforce and SPP also allege that TransAlta's proposed tariff would "subject ratepayers entirely unconnected to its costs to a surcharge above the rate on file for the service they performed or received, if any," in violation of the filed rate doctrine and rule against retroactive ratemaking. *Id.* at 29; *see also* Motion for Leave to Answer and Answer of Gridforce Energy Management, LLC, Docket No. ER 2-2422-000 at 7 (June 30, 2026) ["Answer of Gridforce"]. And while the mechanism is not clear, SPP will "pass those costs along to an unknown and unidentified ratepayer via a tariff mechanism." Protest of SPP at 30.

Like the Balancing Authorities and Reliability Coordinators named in the Centralia I, II, and III, ratepayers have received no benefit from TransAlta's efforts to make Centralia

available to operate. Application for Cost Recovery at 11 ("Centralia Unit 2 was not directed to operate pursuant to the Orders. . ."). But here, if FERC grants TransAlta's request to recover costs from BPA, CAISO, Gridforce, or SPP, ratepayers will ultimately foot the bill. DOE issued these Orders in the absence of an emergency *and* Centralia did not operate to supply the grid with power. Nonetheless, these Orders cost nearly $20 million for ratepayers, at a time when electricity prices are already at a record high. *See* Centralia I Rehearing Request at 93–94,

DOE's use of its section 202(c) authority here appears to be driven by political objectives. *See* 90 Fed. Reg. 15517; *see also* FOX 29 PHILADELPHIA, *FULL SIGNING: President Trump signs executive orders on coal mining* (YouTube, April 8, 2025), https://www.youtube.com/watch?v=1TfJUn2VxM4. Notably, the groups involved in the FERC rate proceeding, including a federal agency, effectively confirmed that using section 202(c) to accomplish those objectives is arbitrary and unlawful. *See* Comments of BPA; Protest of CAISO; Protest of Gridforce; Comments of Gridforce Energy Management, LLC, Docket No. ER 26-2422-000 (June 11, 2026) ["Comments of Gridforce"]; Answer of Gridforce; Protest of SPP.

This all supports Washington's position in this rehearing request and its request for rehearing of Centralia I and II that DOE's Orders are arbitrary and capricious, unsupported by substantial evidence, and contrary to law. Indeed, the fact that electricity has not been generated, delivered, or transmitted from Centralia since TransAlta received the first Order on December 16, 2026 makes crystal clear that the nearly $20 million price-tag for TransAlta

to "be made available" for operation, is arbitrary and capricious and will harm ratepayers. Ex. 1.

The costs for ratepayers will not stop at $20 million. As demonstrated by the recent orders affecting other coal facilities, DOE's section 202(c) orders directing Centralia to operate will continue to be issued. In its application for cost recovery, TransAlta acknowledged that keeping Centralia available to operate throughout 2026 will require significant investment and maintenance work, for which it will promptly seek cost recovery. Application for Cost Recovery at 12. While the exact price to ensure Centralia is capable of operation is uncertain, TransAlta estimates costs in Q3 or Q4 of 2026 to total $23,000,000 *in addition* to the nearly $20,000,000 in costs it has already incurred. *Id.* And although FERC has not yet decided on TransAlta's request for cost recovery, it has granted tariff revisions to allocate the costs of keeping other coal plants available to operate pursuant to DOE's recent section 202(c) orders. *See e.g.* 192 FERC ¶ 61,158 (revising MISO Tariff to allocate costs of keeping Campbell Plant in operation). DOE's use of 202(c) to push its pro-coal agenda will continue to cost ratepayers tens of millions of dollars, indefinitely.

DOE issued these Orders based on a generalized finding of emergency, not a particular triggering event, and as a result Centralia has sat idle for seven months. However, even without operating, TransAlta has incurred millions of dollars in costs to keep the plant available to operate. As explained more fully in Washington's earlier rehearing requests, this Order is inconsistent with the requirements of section 202(c), is arbitrary and capricious, and will harm consumers.

C. Columbia River Power System Restrictions Imposed by the Oregon District Court do not Threaten Grid Reliability

As in Centralia II, DOE again asserts that regional electricity reliability is threatened by restrictions imposed on the Federal Columbia River Power System by a preliminary injunction issued by the United States District Court for District of Oregon. Ex. 120 at 6. Specifically, DOE asserts that the restrictions in the injunction will impact BPA's ability to provide reliable power and transmissions services, resulting in a "substantial increased risk" to regional power reliability. *Id*. at 6. This assertion is fundamentally flawed on multiple levels.

First, after Washington pointed out that DOE in Centralia II cited the wrong version of preliminary injunction, DOE corrects that reference in Centralia III. But DOE's reliance on the Columbia River Order is still misplaced and incorrect. DOE persists in making argument from BPA's briefing about a requested injunction that was never issued. Specifically, DOE relies on arguments from declarations submitted by BPA dealing with a proposed injunction, rather than the injunction actually issued by the court with critically different terms and based on modeling of the operational measures in BPA's briefing for preliminary injunction that, again, was not granted. *See* Ex. 120 at 6. In doing so, DOE entirely ignores that the actual injunction issued by the district court specifically accommodated power reliability concerns by allowing more water for power generation, routine flexibility for energy needs, and exceptions providing relief from operational conditions if there were an energy reliability emergency. Ex. 114-1 at 17–19 (*Nat'l Wildlife Fed'n v. NMFS* Injunction). Moreover, the arguments and evidence BPA submitted in its briefing and now relied on by DOE were considered and, where not specifically addressed by the final terms of the

injunction, they were rejected by the district court as unsupported. *Id.* DOE's reliance on the injunction to support its emergency finding is wholly misplaced.

Second, in response to the very power reliability concerns that had been raised, the district court rejected the BPA's request to set reservoir levels at Minimum Operating Pool ("MOP") and instead ordered reservoir levels to be maintained at the higher Minimum Irrigation Pool ("MIP") level, affording more water for electricity production as well as for irrigation. *Id*. at 17. These are not the reservoir levels that were the subject of the briefing and evidence relied on now by DOE to assert that the injunction will cause grid instability. For example, Centralia III cites BPA staff declarations that evaluated power reliability impacts for the reservoir forebay levels at the plaintiffs' requested MOP level, not the MIP level ultimately set by the court in the injunction. Ex. 120 at 6, n.32-34; *see* Ex. 115, Dibble Decl. at ¶¶ 19, 28, 40; Ex. 116, Stevenson Decl. at ¶¶ 21, 24–27. As the court noted, however, setting reservoir levels at MIP in the final injunction, rather than MOP, significantly ameliorated the concerns relating to power system reliability, as well as concerns with flood risk, transportation, irrigation, and availability of water supplies and clean drinking water. Ex. 114-1 at 17.

Third, DOE fails to account for the fact that the court included specific relief valves from the conditions of its preliminary injunction related for electricity reliability. The court included these relief valves for both the reservoir levels as well as spill conditions. Ex. 114-2 at 41–42 (*Nat'l Wildlife Fed'n v. NMFS* Order) ("the Court includes flexibility of the Action Agencies to deviate from these [reservoir] levels for transportation and power generation emergencies . . . [and] builds into the injunction flexibility for the Action Agencies to adjust

spills for emergency power generation and transportation needs"). Thus, before the preliminary injunction could cause any energy emergency, relief from its provisions is plainly available. As in Centralia II, DOE acknowledges none of this in Centralia III.

Fourth, the district court also rejected many of the Federal Defendant's grid reliability concerns (such as their concerns with spill provisions) as overblown, unsupported, and contrary to the scientific record in the case. *Id*. at 38. The court observed that recent Columbia River System operations with spill conditions and reservoir levels similar to what is imposed in the preliminary injunction have consistently been workable and not resulted in grid instability. *Id*. In fact, the court noted that since 2023 the Northwest Power and Conservation Council (the organization responsible for assessing regional power demand and reliability) "has found the regional power system to be reliable and anticipates that the system will continue to meet reliability standards." *Id*. (citing Ex. 117, Hirsch Decl. ¶¶ 12–18); *see also* Ex. 114-2 at 10–11 (recounting 2023 stay of litigation and MOU). The court went on to find that "the routine variances and adjustments that have helped to support that reliability will continue to be available to Federal Defendants under the injunction." *Id*.

DOE's assertions in Centralia III regarding the district court's injunction are based on outdated and not relevant briefing and declarations submitted by BPA in the midst of litigation and ignore key aspects of the actual injunction issued by the district court, which provides flexibility if needed for an actual emergency. The preliminary injunction affecting operation of the Columbia River Power System does not represent a risk to regional energy reliability. Not only did the court address, *and reject*, this very argument in its detailed ruling, it went to some length to accommodate power reliability concerns in crafting its injunction. The

injunction neither threatens grid reliability nor substantially increases the risk of an electricity reliability emergency. DOE's reliance on it here to declare a continuing "emergency" in Centralia III is arbitrary, capricious, and unlawful.

VI. REQUEST FOR STAY

Washington State further moves DOE for a stay of the Order until judicial review has concluded. 18 C.F.R. § 385.212. DOE has the authority to issue a stay under the Administrative Procedure Act where "justice so requires." 5 U.S.C. § 705.

To determine whether to grant a request for stay, agencies consider: (1) whether the requesting party will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

A. Washington State Will Suffer Irreparable Injury Without a Stay

A stay is necessary to prevent irreparable harm to Washington State caused by Centralia II. Injuries must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (identifying that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").

Economic injury is irreparable only where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958). Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

Centralia III imposes costs on Washington ratepayers that may not be recoverable through future litigation and would not have otherwise been expended absent the Centralia III. Assuming TransAlta complies with Centralia III,[11] it will expend considerable costs preparing the plant for refiring—if the plant is idle but available to operate *or* actively producing coal-fired power. *See supra* Section III at 10–11, Section IV.H.1. TransAlta will continue to generate staffing and overhead expenses under either scenario. Firing up the plant and transmitting electricity will further increase expenses. And plainly, coal is more expensive. Ex. 41 at ¶ 15 ("Under its current Purchase Power Agreement (PPA), the energy price from Centralia's coal is significantly higher than the wholesale energy market price. Specifically, under the current contract, Puget Sound Energy pays $62.04 per MWh, while the wholesale market price is $54.32 per MWh."). Centralia III again directs TransAlta to recover its expenses through a FERC tariff revision. Order at 4; 16 U.S.C. § 824a(c). Neither Centralia

[11] There is no indication that TransAlta will not comply with the Order, to the extent it understands what the Order requires it to do.

III nor the statute identify a mechanism for "corrective relief" should Centralia III be found unlawful. As there is no clear recourse to recovering these costs should Washington State prevail in its challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases.

Environmental injury is inevitable whether Centralia III requires TransAlta to immediately operate Centralia as a coal plant, or it operates intermittently from a stand-by posture. As described in the Rehearing Request, Washington residents will suffer environmental health and environmental harms because of the Centralia II. *See supra* Section III at 8, Section IV.H.3. TransAlta's Centralia Coal Plant is a significant source of particulate matter, sulfur dioxide, and nitrogen oxides. Ex. 10 at ¶ 7. Those emissions are known to adversely impact human health. Based on estimates from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), the failure to cease operations at Centralia will contribute to an estimated 9-13 premature deaths, 3 nonfatal heart attacks, 53 cases of asthma onset, and $140-210 million in health care costs and lost economic activity in Washington annually. Ex. 10 at ¶ 10. Further, Centralia is the highest source of greenhouse gas emissions in Washington. Ex. 12; Ex. 13. A local clean air agency issued Centralia two notices of violation for exceeding emissions limits in December 2025. Ex. 11 at ¶ 12. Emissions are expected to be even higher if Centralia cannot operate at a lower load or make necessary repairs, or cease operations entirely as it had planned to do prior to DOE's orders. Ex. 11 at ¶ 11. Because the environmental injury to Washington State and its residents cannot be adequately remedied and may be permanent or long duration and is sufficiently likely, a stay pending judicial review is necessary.

B. A Stay Would Not Substantially Harm Other Parties

No parties would be harmed by a stay of Centralia III because no emergency exists and the Centralia III order was never needed to begin with. As detailed above, an order under 202(c) must be limited to circumstances that are imminent and unforeseen. *See supra* VI.A. Centralia III again provides no evidence to support a claim of an imminent emergency and references potential *future* grid unreliability. *See supra* VI.C.1. The State supplies substantial evidence to support the absence of an energy emergency. Because no current emergency exists, no other party could be harmed. Not forcing the deployment of coal plant that is not needed harms no one. A stay would not disrupt the local energy market or impair the provision of electricity to customers.

C. A Stay is in the Public Interest

Centralia III is contrary to the public interest. A stay will prevent any potential harm to the public that will be caused by Centralia III. Principally, Centralia III fails to meet the public interest standard under the Act DOE relies upon, i.e., 16 U.S.C. § 824a(c)(1), in bringing Centralia III. *See* Centralia I Rehearing Request VI.D.2. Further, if a true energy emergency existed, the public interest would not be served by an aging, unreliable coal plant that requires 12–18 hours to start up. Ex. 11 at ¶¶ 7, 8. Centralia III has the potential to throw the regional energy market into short-term and long-term uncertainty, both of which could have adverse consequences for energy users—the public. *See* Centralia I Rehearing Request VI.E.1. A stay is in the public interest.

VII. CONCLUSION

For the reasons set forth above, Washington respectfully requests that DOE grant intervention, grant rehearing, and rescind Centralia III in its entirety.

Dated this 10th day of July, 2026.

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State of Washington

Request for Rehearing of Order No. 202-26-28

Index of Exhibits

No.	Exhibit Name	Document Name	URL
Centralia I			
1	DOE Order No. 202-25-11	Department of Energy (DOE), Washington DC 20585, Order No. 202-25-11 (Dec. 16, 2025)	
2	NERC 2025–2026 Winter Reliability Assessment	North American Electric Reliability Corporation, 2025–2026 Winter Reliability Assessment (Nov. 2025)	
3	E3 Slide Deck	Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results, dated September 22, 2025	
4	DOE Resource Adequacy Report	DOE Resource Adequacy Report, Evaluating the Reiliability and Security of the U.S. Electric Grid (July 2025)	

No.	Exhibit Name	Document Name	URL
5	Memorandum of Agreement	Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Dec. 23, 2011)	
6	2017 Amended Memorandum of Agreement	First Amendment to Memorandum of Agreement, TransAlta-State of Washington (fully executed) (Jul. 13, 2017)	
7	2011 BART Order	Dep't of Ecology Administrative Order, First Revision: Order No. 6426 (Dec. 13, 2011)	
8	2020 BART Order	Dep't of Ecology Administrative Order, Second Revision: Order No. 6426 (Jul. 29, 2020)	
9	Technical Support Data-2020 BART Order	Dep't of Ecology Technical Support Document for Second BART Order Revision, TransAlta Centralia Generation Plant (July 2020)	

No.	Exhibit Name	Document Name	URL
10	Palcisko Declaration	Declaration of Gary Palcisko in Support of Request for Rehearing by State of Washington	
10-1	COBRA Data Coal v. Cease Operations	Total Health Benefits, Lewis County, Washington	
10-2	COBRA Data Coal v. Natural Gas	Total Health Benefits, Lewis County, Washington	
10-3	2023 Emissions Inventory	2023 Emissions Inventory	
11	Lamoreaux Declaration	Declaration of Clinton Lamoreaux in Support of Request for Rehearing by State of Washington	
11-1	TransAlta Centralia Title V Quarterly Report First Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan. 1 - March 31, 2025	

No.	Exhibit Name	Document Name	URL
11-2	TransAlta Centralia Title V Quarterly Report Second Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, April 1-June 30, 2025	
11-3	TransAlta Centralia Title V Quarterly Report Third Quarter 2025	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2025	
11-4	TransAlta Centralia Title V Quarterly Report First Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan 1 – March 31, 2024	
11-5	TransAlta Centralia Title V Quarterly Report Second Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, Apr. 1 – June 30, 2024	
11-6	TransAlta Centralia Title V Quarterly Report Third Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2024	

No.	Exhibit Name	Document Name	URL
11-7	TransAlta Centralia Title V Quarterly Report Fourth Quarter 2024	Title V Report Certification Form, TransAlta Centralia Generation LLC, Fourth Quarter, Oct. 1 – Dec. 31, 2024	
11-8	TransAlta Centralia Title V Quarterly Report First Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, First Quarter, Jan. 1 – Mar. 31, 2023	
11-9	TransAlta Centralia Title V Quarterly Report Second Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Second Quarter, Apr. 1 – Jun 30, 2023	
11-10	TransAlta Centralia Title V Quarterly Report Third Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Third Quarter, Jul. 1 – Sep. 30, 2023	
11-11	TransAlta Centralia Title V Quarterly Report Fourth Quarter 2023	Title V Report Certification Form, TransAlta Centralia Generation LLC, Fourth Quarter, Oct. 1 – Dec. 31, 2023	

No.	Exhibit Name	Document Name	URL
11-12	Photograph of opacity readings	Photograph of opacity readings on Oct. 23, 2025	
11-13	Centralia Plant's 2022 U2 Boiler Tune-up Report	TransAlta Centralia U2 Boiler, 40 CFR 63 DDDDD Tune-Up Report (Oct. 3, 2022)	
11-14	Notice of Violation No. 10642, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Oct. 23, 2025	
11-15	Notice of Violation No. 10643, TransAlta	Southwest Clean Air Agency, Notice of Violation, No. 10643, TransAlta, Jan 11, Mar. 4, Jun. 6, Jun. 11, Aug. 26, 2025	
12	Top 10 Stationary Sources of GHG Emissions in WA – 2022	Dep't of Ecology Data Base: Top 10 Stationary Sources of Greenhouse Emissions in Washington (2022)	

No.	Exhibit Name	Document Name	URL
13	2023 EPA Top CO2 Emissions	U.S. Env't Prot. Agency, Greenhouse Gas Reporting Program (GHGRP), Top Washington Greenhouse Gas emissions sources for 2023, *GHGRP State and Tribal Fact Sheet* (last visited Jan. 6, 2026)	https://www.epa.gov/ghgreporting/ghgrp-state-and-tribal-fact-sheet
14	U.S. Energy Information – Start Up	U.S. Energy Information Administration, Owen Comstock, *About 25% of U.S. power plants can start up within an hour* (Nov. 19, 2020)	https://www.eia.gov/todayinenergy/detail.php?id=45956)
15	Plant Job Underway	Centralia Daily Chronicle, *Plant Job Underway* (Jun. 14, 1968)	
16	2021 Title V Air Operating Permit	TransAlta Centralia Generation, LLC, Centralia Plant, Air Operating Permit SW-98-8-R5A, Southwest Clean Air Agency (Sep. 22, 2021)	

No.	Exhibit Name	Document Name	URL
17	2021 Title V Air Operating Permit - Basis Statement		
18	U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860)		https://www.eia.gov/electricity/data/eia860/
19	2022 Visibility SIP	Washington Dep't of Ecology, Air Quality Program, *State Implementation Plan Revision, Second Regional Haze Plan* (2018 – 2028) (Jan. 2022)	
20	TransAlta News Release Announcing Coal to Gas Conversion Project	TransAlta, Alberta Calgary, News Release, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/

No.	Exhibit Name	Document Name	URL
21	TransAlta Permit Application	TransAlta Centralia Generation, LLC, *Prevention of Significant Deterioration Permit Application* (Dec. 2025)	
22	Letter Re: Summary of the 2025 Long-term Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Long-term Resource Adequacy Meeting* (Nov. 19, 2025)	
23	2025 DOE 202(c) Orders	2025 DOE 202(c) Orders	https://www.energy.gov/ceser/2025-doe-202c-orders
23-1	Order (Dec. 14, 2000)	U.S. Dep't of Energy, Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000) (California Energy Crisis in 2000)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

No.	Exhibit Name	Document Name	URL
23-2	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	DOE Order No. 202-05-1 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-3	DOE Order No. 202-05-2 (Sep. 8, 2005)	DOE Order No. 202-05-2 (Sep. 8, 2005) (Hurricane Rita)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-4	DOE Order No. 202-08-1 (Sep. 14, 2008)	DOE Order No. 202-08-1 (Sep. 14, 2008) (Hurricane Ike)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-5	DOE Order No. 202-20-1 (Aug. 27, 2020)	Ex. 23-9 (DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-6	DOE Order No. 202-20-2 (Sep. 6, 2020)	DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-7	DOE Order No. 202-21-1 (Feb. 14, 2021)	DOE Order No. 202-21-1 (Feb. 14, 2021) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-8	DOE Order No. 202-21-2	DOE Order No. 202-21-2) (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

No.	Exhibit Name	Document Name	URL
23-9	DOE Order No. 202-22-1	DOE Order No. 202-22-1 (extreme heat, wildfires and drought in California)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-10	DOE Order No. 202-22-2	Exs. 23-13 and 23-14 (DOE Order Nos. 202-22-1 & 2 and amendments) (same)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-11	DOE Order No. 202-22-3 (Dec. 23, 2022)	DOE Order No. 202-22-3 (Dec. 23, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-12	DOE Order No. 202-22-4 (Dec. 24, 2022)	DOE Order No. 202-22-4 (Dec. 24, 2022) (extreme cold)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-13	DOE Order No. 202-24-1 (Oct. 9, 2024)	Ex. 23-20 (DOE Order No. 202-24-1 (Oct. 9, 2024)) (Hurricane Milton)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-14	DOE Order No. 202-05-3 (Dec. 20, 2005)	DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant, DC)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-15	DOE Order No. 202-17-1	DOE Order No. 202-17-1 (GRDA)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

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23-16	DOE Order No. 202-17-2	DOE Order No. 202-17-2 (Yorktown Power Station)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
23-17	DOE Order No. 202-17-4 (Sept. 14, 2017)	DOE Order No. 202-17-4 (Sept. 14, 2017) (Yorktown Power Station – extension)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
24	Grand River Dam Authority Request for Emergency Order	Daniel S. Sullivan, Grand River Dam Authority, *Re: Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (April 11, 2017)	https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf
25	Wagner Order No. 202-25-6	U.S. Dep't of Energy, Order No. 202-25-6 (Jul 28, 2025)	
26	Puerto Rico Electric Power Authority, Order No. 202-25-1	U.S. Dep't of Energy, Order No. 202-25-1 (May 16, 2025)	
27	Campbell Order	U.S. Dep't of Energy, Order No. 202-25-3 (May 23, 2025)	https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf https://perma.cc/Q7P7-TDTX

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28	Eddystone Order	U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025)	https://perma.cc/PS3M-6CJA
29	Trump Admin Ordered Coal Plan Stay Open	Ella Nilsen, CNN, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill* (June 6, 2025)	https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright
30	CMS Energy Quarterly Report	U.S. Securities and Exchange Commission, Form 10-Q, *Quarterly Report for CMS Energy Corp.* (Jul. 31, 2025)	https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm
31	Trump Administration Forcing Coal Plants to Stay Open	NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025)	https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first

No.	Exhibit Name	Document Name	URL
32	U.S. Dep't of Energy Fact Sheet	U.S. Dep't of Energy, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025)	https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf https://perma.cc/YLX7-8G7T
33	Press Release Dep't of Energy U.S. Grid Report	Press Release, U.S. Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security https://perma.cc/8TEJ-AGH6
34	Campbell Rehearing Order	U.S. Dep't of Energy, Order No. 202-25-3B, Order Addressing Arguments Raised on Rehearing (Sep. 8, 2025	

No.	Exhibit Name	Document Name	URL
35	August 6, 2025 State Request for Rehearing	Before the U.S. Dep't of Energy, In Re: Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, July 2025, Motion to Intervene and Protective Request for Rehearing (Aug. 6, 2025)	
35-1	August 6 Rehearing Request Exhibit A	North American Electric Reliability Corp (NERC) *Interregional Transfer Capability Study (ITCS)*, Final Report, Nov. 2024	
35-2	August 6 Rehearing Request Exhibit B	GridLab Analysis: Department of Energy Resource Adequacy Report (July 15, 2025)	
35-3	August 6 Rehearing Request Exhibit C	New York University School of Law, Institute for Policy Integrity, *Enough Energy A Review of DOE's Resource Adequacy Methodology* (July 2025)	

No.	Exhibit Name	Document Name	URL
35-4	August 6 Rehearing Request Exhibit D	Nicholas Institute for Energy, Environment & Sustainability, *Rethinking Load Growth* (2025)	
35-5	August 6 Rehearing Request Exhibit E	London Economics Internat'l, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* (Jul 7, 2025)	
35-6	August 6 Rehearing Request Exhibit F	Grid Strategies, *Resource Adequacy Value of Interregional Transmission* (Jun. 2025)	
36	Second Campbell Order	U.S. Dep't of Energy, Order No. 202-25-9 (Nov. 18, 2025)	
37	Schahfer Order	U.S. Dep't of Energy, Order No. 202-25-12 (Dec. 23, 2025)	
38	Culley Order	U.S. Dep't of Energy, Order No. 202-25-13 (Dec. 23, 2025)	

No.	Exhibit Name	Document Name	URL
39	PJM Manual	Capacity Market & Demand Response Operations, *PJM Manuel 18: PJM Capacity Market* (Effective Date: Jul. 23, 2025)	
40	Eddystone Request for Rehearing	Before the U.S. Dep't of Energy, Order No. 202-25-4, Motion to Intervene and Request for Rehearing	
41	Moriyasu Declaration	Declaration of Callahan Moriyasu in Support of Request for Rehearing by State of Washington	
41-1	Historic Trends in Energy Use	Northwest Power and Conservation Council, *Historic Trends in Energy Use*	
41-2	Northwest Heat Wave	U.S. Energy Information Administration, *Northwest heat wave leads to record levels of summer electricity demand* (Aug. 23, 2017)	

No.	Exhibit Name	Document Name	URL
41-3	Ancillary Services Definitions and Capability Study	GE Energy Consulting, Ancillary Services Definitions and Capability Study (Dec. 2012)	
41-4	Optimizing Reserves	Electricity Advisory Committee, *Optimizing Reserves* (Oct. 2019)	
41-5	Historical Data	Bureau of Reclamation, Historical Data Access, Grand Coulee Dam (2020-2025)	https://www.usbr.gov/pn/hydromet/arcread.html
41-6	Washington Water Conditions	USGS Water Data for the Nation, *Washington Water Conditions* (Dec. 31, 2025)	
41-7	Water Management Data	U.S. Army Corps of Engineers, *Water Management Data* (Dec. 31, 2025)	
41-8	Grand Coulee Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Manage-ment Data, Grand Coulee Dam, Pacific Northwest Region, Dec. 2025	

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41-9	Chief Joseph Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Chief Joseph Dam, Pacific Northwest Region, Dec. 2025	
41-10	Lower Granite Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Lower Granite Lock and Dam, Walla Walla District, Dec. 2025	
41-11	Little Goose Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Little Goose Lock and Dam, Walla Walla District, Dec. 2025	
41-12	Lower Monumental Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Lower Monumental Lock and Dam, Walla Walla District, Dec. 2025	
41-13	Ice Harbor Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Ice Harbor Lock and Dam, Walla Walla District, Dec. 2025	

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41-14	McNary Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, McNary Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-15	John Day Lock and Dam Levels Dec 2025	U.S. Army Corps of Engineers, Water Management Data, John Day Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-16	The Dalles Lock and Dam Levels Dec 2025	U.S. Army Corps of Engineers, Water Management Data, The Dalles Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-17	Bonneville Lock and Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Bonneville Lock and Dam, Pacific Northwest Region, Dec. 2025	
41-18	Priest Rapids Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Priest Rapids Dam, Pacific Northwest Region, Dec. 2025	

No.	Exhibit Name	Document Name	URL
41-19	Wanapum Dam Levels, Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Wanapum Dam, Pacific Northwest Region, Dec. 2025	
41-20	Rock Island Dam Levels Dec. 2025	U.S. Army Corps of Engineers, Water Management Data, Rock Island Dam, Pacific Northwest Region, Dec. 2025	
41-21	NOAA NWS Three Month Outlook	NOAA, Nat'l Weather Service, *Three-Month Outlooks*, Official Forecasts Jan-Feb-Mar 2026	
41-22	Centralia Coal PPA (R)	Puget Sound Energy, Docket UE-250747, Attachment B (Impact of portfolio updates), *Sheet "Centralia Coal PPA(R)"* (Oct. 1, 2025)	
41-23	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025–2030	

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42	Press Release Re: Executive Order	U.S. Dep't of Energy, *Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter* (Dec. 17, 2025)	
43	Promises Made Promises Kept	U.S. Dep't of Energy, *Promises Made, Promises Kept, Unleashing the Golden Era of Energy Dominance and Lowering Prices* (Dec. 18, 2025)	
44	Executive Order 14156	Administration of Donald J. Trump, 2025, Executive Order 14156- Declaring a National Energy Emergency (Jan. 20, 2025)	
45	E2 Clean Economy Works: Nov. 2025 Analysis	Michael Timberlake, E2 Economy + Environment, Clean Economy Works: November 2025 Analysis (Dec. 12, 2025)	

No.	Exhibit Name	Document Name	URL
46	Energy Department Announces Termination of 223 Projects	U.S. Dep't of Energy, *Energy Department Announces Termination of 223 Projects, Saving Over $7.5 Billion* (Oct. 2, 2025)	
47	Archive of Energy Reliability and Resilience	U.S. Dep't of Energy, Office of Energy Efficiency & Renewable Energy, *Energy Reliability and Resilience*	
48	Dep't of Energy Response to State Rehearing Request of August 6	U.S. Dep't of Energy, *Re: August 6, 2025 Submission* (Sep. 5, 2025)	
49	Gomez Declaration	Declaration of David C. Gomez in Support of Request for Rehearing by State of Washington	
49-1	Centralia Power Plant Profile	S&P Capital IQ, Centralia Power Plant Profile	
49-2	Centralia Power Plant Financials	S&P Capital IQ, Centralia Power Plant Financials	

No.	Exhibit Name	Document Name	URL
50	Reeves Declaration	Declaration of Andrew Reeves in Support of Request for Rehearing by State of Washington	
50-1	Puget Sound Energy 2023 Electric Progress Report	Puget Sound Energy, *2023 Electric Progress Report*, Chapters 1-9 (2023)	
50-2	2025 Avista Electric Integrated Resource Plan	Avista, *Electric Integrated Resource Plan* (2025)	
50-3	Puget Sound Energy 2021 Integrated Resource Plan	Puget Sound Energy, *2021 PSE Integrated Resource Plan,* Chapters 1-9 (Apr. 2021)	
50-4	Letter Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting	Brian Rybarik, WA Utilities and Transportation Commission, Jennifer Grove, WA Dep't of Commerce, *Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting* (Dec. 31, 2025)	

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50-5	Jan 2024 Month In Review	Nat'l Weather Service, Pendleton OR, *The Month In Review, January 2024*	
50-6	WRAP Assessment of January 2024	WRAP, *Assessment of January 2024 Cold Weather Event*	
50-7	Reliability Coordinator Procedure, No. RC-410	California ISO, RC West, Reliability Coordinator Procedure, RC0410 (May 1, 2025)	
50-8	Western Energy Imbalance Market (WEIM)	Western Energy Markets	https://www.westernenergymarkets.com/western-energy-imbalance-market-weim
50-9	CAISO WEIM Fact Sheet	California Independent System Operator (CAISO) Fact Sheet, *Western Energy Imbalance Market* (WEIM)	https://www.caiso.com/Documents/western-energy-imbalance-market-fact-sheet.pdf
50-10	Pennington WRAP Area Map	David Pennington, WPP, Western Resource Adequacy Program (WRAP) Area Map (last modified Oct. 31, 2025)	https://www.westernpowerpool.org/news/wrap-area-map

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50-11	Avista Investor Overview	Avista, *Better energy for life*, Investor overview	https://investor.avistacorp.com/
50-12	RC West California ISO	California ISO, RC West	https://www.caiso.com/market-operations/products-services/rc-west
51	Nightingale Declaration	Declaration of Joel Nightingale in Support of Request for Rehearing by State of Washington	
51-1	Testimony of Ronald J. Roberts, RJR-1T	Washington Utilities and Transportation Commission, Docket Nos. UE-240004 and UG-240005, Prefiled Direct Testimony of Ronald J. Roberts (Feb. 15, 2024)	
51-2	Winter Reliability and Electric-Gas Coordination Slides for WUTC Resource Adequacy Meeting	Zapotocky, Electric Reliability & Security for the West, *Winter Reliability and Electric-Gas Coordination*; North American Electric Reliability Corporation (NERC), *NERC's Winter Reliability Assessment* (Nov. 4, 2025)	

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51-3	Short-Term Energy Outlook US EIA	U.S. Energy Information Administration, *Short-Term Energy Outlook* (Dec. 2025)	https://www.eia.gov/outlooks/steo/
51-4	Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025	U.S. Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook in 2025* (Apr. 2025)	https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2025_LCOE_report.pdf
51-5	Generating Resource Reference Plants: Natural Gas	Northwest Power and Conservation Council, *Generating Resource Reference Plants, Natural Gas*	https://www.nwcouncil.org/2021powerplan_natural-gas_generating-resource-reference-plants/
51-6	Recent Changes to US Coal Plant Operations and Current Compensation Practices	National Association of Regulatory Utility Commissioners, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan. 2020)	https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45
51-7	2024 State of Reliability	North American Electric Reliability Corporation, 2024 State of Reliability (Jun. 2024)	https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2024_technical_assessment.pdf

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52	Middleton Declaration	Declaration of Thomas Middleton in Support of Request for Rehearing by State of Washington	
52-1	Model Toxics Control Act	Washington Dep't of Ecology, Model Toxics Control Act	https://ecology.wa.gov/spills-cleanup/contamination-cleanup/rules-directing-our-cleanup-work/model-toxics-control-act (Last visited January 5, 2026)
52-2	TransAlta Agreed Order	Washington Dep't of Ecology, Agreed Order No. DE 24235 with TransAlta Centralia Generation LLC for TransAlta Centralia (Dec. 29, 2025)	
52-3	Quick Facts Centralia WA	U.S. Census Bureau, Quick Facts Centralia (last visited Jan. 8, 2026)	https://www.census.gov/quickfacts/fact/table/centraliacitywashington/RTN131222
52-4	Data USA	Data USA, Centralia WA, Metropolitan Statistical Area (last visited Jan. 8, 2026)	https://datausa.io/profile/geo/centralia-wa-31000US16500

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52-5	Emissions of Hazardous Air Pollutants	Environmental Health & Engineering, Inc. *Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants* (Mar. 7, 2011)	
53	Rybarik Declaration	Declaration of Brian Rybarik in Support of Request for Rehearing by State of Washington	
54	FEMA Declaration of Emergency	U.S. Dep't of Homeland Security, FEMA, *Emergency Declaration*, FEMA-3629-EM (Dec. 9, 2025)	
55	Best Practices Resource Planning	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024, Revised Dec. 2024)	https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf https://perma.cc/D68F-WHWQ

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56	Trump Signs Executive Orders	New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025)	
57	Declared National Energencies	Brennan Center for Justice, Declared National Emergencies under the National Emergencies Act	https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act
58	Campbell Order No. 202-25-7	Dep't of Energy Order No. 202-25-7 (Aug 20, 2025)	
59	Eddystone Order No. 202-25-8	Dep't of Energy Order No. 202-25-8 (Aug. 27, 2025)	
60	Trump Order Keep Michigan Power Plant Open	Tom Perkins, *Trump Order to Keep Michigan Power Plan Open Costs Taxpayers $113m* (Nov. 28, 2025)	https://www.theguardian.com/us-news/2025/nov/28/trump-michigan-power-plant
61	Short-Term Energy Outlook Browser	U.S. Energy Information Administration, Short-Term Energy Outlook Data Brower (Dec. 9, 2025)	https://www.eia.gov/outlooks/steo/data/browser

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62	U.S. Frackers and Saudi Officials Tell Trump They Won't Drill More	Wall Street Journal, *U.S. Frackers and Saudi Officials Tell Trump They Won't Drill More* (Feb. 3, 2025)	https://www.wsj.com/business/energy-oil/trump-oil-drilling-saudi-arabia-71c095ff?reflink=desktopwebshare_permalink
63	Eddystone Order No. 202-25-10	Dep't of Energy Order No. 202-25-10 (Nov. 25, 2025)	
64	Winter Outlook 2025-2026	US Dep't Commerce, Nat'l Oceanic and Atmospheric Admin., Nat'l Weather Service, *Winter Outlook 2025-2026*, at 4 (Last visited Jan. 6, 2025)	https://www.weather.gov/media/abr/sitreport/2025-2026WinterOutlook.pdf
65	TransAlta Signs Agreement	*TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion*, TransAlta (Dec. 31, 2025, 9:39 AM)	https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

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66	TransAlta Conversion	Jacob Moore, @chronline.com, *Announcement comes as company must take its coal-fired burner offline; 700 jobs expected at peak of construction, 40 to be employed permanently* (Dec. 10, 2025)	https://www.chronline.com/stories/transalta-centralia-to-transition-from-coal-to-natural-gas,392533
67	Best Practices Resource Planning (PDF Exhibit Parts 1-7)	Synapse Energy Economics, Lawrence Berkeley Nat'l Laboratory, *Best Practices in Integrated Resource Planning* (Nov. 2024)	https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf
68	Trump Vowed Make Coal King	Hanna Northey, EE News, *Trump has vowed to make coal king again. How's it going?* (Sep. 24, 2025)	https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf
69	Interior Approves Mining Plan	U.S. Dep't of the Interior, *Interior Approves Mining Plan to Unlock 14.5 Million Tons of Coal at Antelope Mine* (Wyoming) (Aug. 2025)	https://www.doi.gov/pressreleases/interior-approves-mining-plan-unlock-145-million-tons-coal-antelope-mine

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70	Donors Benefit from Trump Return to Office	Karen Yourish, Kenneth Vogel, Charlie Smart, The New York Times, *Hundreds of Big Post-Election Donors Have Benefited from Trump's Return to Office* (Dec. 22, 2025)	https://www.nytimes.com/interactive/2025/12/22/us/politics/trump-donors-fundraising-benefits.html
71	White House Offers Concierge Service	Jake Spring, *White House offers 'concierge' service to fossil fuel firms, official says* (Updated Oct. 7, 2025)	https://www.washingtonpost.com/climate-environment/2025/10/07/white-house-fossil-fuel-concierge/
72	Trump Admin. Reconsiders Rule	Rachel Frazin, The Hill, *Trump admin will reconsider part of rule to protect miners from lung diseases* (Dec. 1, 2025)	https://thehill.com/policy/energy-environment/5628531-miner-lung-disease-rule-silica/
73	Trump Wants Mining	Hannah Northey, EENews, T*rump wants mining. Federal mine safety workers are on the chopping block* (Sep. 5, 2025)	. https://www.eenews.net/articles/trump-wants-mining-federal-mine-safety-workers-are-on-the-chopping-block/

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74	Grid Strategies Report	Michael Goggin, Grid Strategies LLC, The Cost of Federal Mandates to Retain Fossil-Burning Power Plants (Aug. 2025)	
75	Notice to Stakeholders	U.S. Dep't of Labor, Mine Safety and Health Admin., *Notice to Stakeholders*	https://www.msha.gov/notice-stakeholders
76	Columbia River Basin Dams	U.S. Army Corps of Engineers, NW Division Website, *Columbia River Dams* accessed Dec. 30, 2025)	https://www.nwd.usace.army.mil/crwm/cr-dams/
77	Hydropower Impact – Bonneville Power Admin.	Bonneville Power Administration, *Hydropower Impact; All About Federal Hydropower, the Largest Source of Clean Power in the U.S.* (Last accessed Dec. 30, 2025)	https://www.bpa.gov/energy-and-services/power/provider-of-choice/resources
78	Hydropower Flows Here – Bonneville Power Admin.	Bonneville Power Administration, *Hydropower Flows Here* (Last accessed Dec. 30, 2025)	https://www.bpa.gov/learn-and-participate/community-education/hydropower-flows-here

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79	BPA Maintains Strong Financial Position	Bonneville Power Administration, Newsroom, *BPA maintains strong financial position despite challenging water year* (Nov. 13, 2025)	https://www.bpa.gov/about/newsroom/news-articles/20251113-bpa-maintains-strong-financial-position-despite-challenging-water-year
80	Pacific Moisture Drenches the U.S. Northwest	NASA Earth Science, *Pacific Moisture Drenches the U.S. Northwest* (Dec. 12, 2025)	https://science.nasa.gov/earth/earth-observatory/pacific-moisture-drenches-the-u-s-northwest/
81	President Approves Washington Emergency Declaration	U.S. Dep't of Homeland Security, FEMA, *President Donald J. Trump Approves Emergency Declaration for State of Washington* (Dec. 12, 2025)	https://www.fema.gov/press-release/20251212/president-donald-j-trump-approves-emergency-declaration-state-washington
82	Federal Teams Support State-Led Response to Washington Storms	U.S. Dep't of Homeland Security, FEMA, *Federal Teams Support State-Led Response to Historic Washington Severe Storms and Flooding* (Dec. 23, 2025)	https://www.fema.gov/blog/federal-teams-support-state-led-response-historic-washington-severe-storms-and-flooding

No.	Exhibit Name	Document Name	URL
83	Stopping Radical Environ-mentalism to Generate Power	Presidential Actions, Presidential Memoranda, *Stopping Radical Environmentalism to Generate Power for the Columbia River Basin*, (Jun. 12, 2025)	https://www.whitehouse.gov/presidential-actions/2025/06/stopping-radical-environmentalism-to-generate-power-for-the-columbia-river-basin/ (last accessed January 5, 2026)
84	Electricity Data Browser	U.S. Energy Info. Admin., *Electricity Data Browser*, EIA (last visited Nov. 4, 2025)	https://www.eia.gov/electricity/data/browser/#/topic/7
85	Consumer Prices Up 2.9% August 2024 to August 2025	U.S. Bureau of Labor Statistics, *Consumer prices up 2.9 percent from August 2024 to August 2025*, TED: The Economics Daily (Sept. 17, 2024)	https://www.bls.gov/opub/ted/2025/consumer-prices-up-2-9-percent-from-august-2024-to-auCogust-2025.htm
86	Report: Lack of Affordable Housing Options	Wash. State Dept. of Commerce, *Report: Lack of affordable housing options reaches critical levels in communities throughout Washington state* (May 13, 2024)	https://www.commerce.wa.gov/report-lack-of-affordable-housing-options-reaches-critical-levels-in-communities-throughout-washington-state/
87	Trends in Financial Hardship	United for Alice, *The State of Alice in Washington*, United Way of Northern New Jersey	https://www.unitedforalice.org/trends-in-hardship/Washington

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88	Emission Performance Standard SB 1368	California Energy Commission, Emission Performance Standards – SB 1368	https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/emission-performance-standard-sb-1368
89	Coal and the Environment	U.S. Energy Information Administration, *Coal explained: Coal and the environment* (Last updated: Apr. 17, 2024)	https://www.eia.gov/energyexplained/coal/coal-and-the-environment.php
90	What They are Saying: President Trump Stops Radical Environ-mentalism	The White House Newsletter, *What They Are Saying: President Trump Stops Radical Environmentalism to Generate Power for the Columbia River Basin* (Jun. 13, 2025)	https://www.whitehouse.gov/articles/2025/06/what-they-are-saying-president-trump-stops-radical-environmentalism-to-generate-power-for-the-columbia-river-basin/

No.	Exhibit Name	Document Name	URL
91	Special Environmental Analysis of Balancing Authority of Northern California	U.S. Dep't of Energy, *Special Environmental Analysis of Balancing Authority of Northern California (BANC) Operations during 202(c) Emergency Order Operations between September 4, 2022, and September 8, 2022* (Apr. 19, 2024)	https://www.energy.gov/sites/default/files/2024-08/sea-07-banc-special-environmental-analysis-2024-04-19.pdf
92	SPP Balancing Authority Map	Southwest Power Pool (SPP) Balancing Authority Map	https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png
93	NCR11393 Compliance Audit	Gridforce Energy Management, LLC, Compliance Audit, NCR11393 (Dec. 20, 2019)	
94	Craig Order No. 202-25-14	U.S. Dep't of Energy, Order No. 202-25-14 (Dec. 30, 2025)	

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95	Research Power Corp. Order Authorizing Electricity Exports to Canada	U.S. Dep't of Energy, Grid Deployment Office, Research Power Corporation, GDO Docket No. EA-365-C, Order Authorizaing Electricity Exports to Canada	
96	PJM to Ratchet Down Projected AI Power Demand Eastern US	Peter Behr, Energywire, *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6, 2026)	
97	Declaration of Arne Olson	U.S. of America, Before the Dep't of Energy, Re: Transalta Centralia Generation, Declaration of Arne Olson (Jan. 13, 2026)	
97-1	E3 NW RA Data for Washington	E3, Greater Northwest System Metrics 2025-2030	

No.	Exhibit Name	Document Name	URL
98	Final Order Granting Petition	Washington Utilities and Transportation Commission, Re: Puget Sound Energy, Docket UE-121373, Order 03, Final Order Granting Petition, Subject to Conditions (Jan. 9, 2013)	
99	E3 Northwest Resource Adequacy Study Review	Sylvan Energy Analytics, GridLab, *Near-term winter resource adequacy challenges in the Pacific Northwest, A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges* (January 2026)	
Centralia II			
100	Order No. 202-26-18	Dep't of Energy, *Order No. 202-26-18* (Mar. 16, 2026)	
101	February Campbell Order	Dep't of Energy, *Order No. 202-26-16* (Feb. 17, 2026)	

No.	Exhibit Name	Document Name	URL
102	Eddystone Order	Dep't of Energy, *Order No. 202-26-17* (Feb. 23, 2026)	
103	Second Lamoreaux Declaration	Second Declaration of Clinton Lamoreaux in Support of Motion to Intervene, Request for Rehearing, and Motion to Stay by State of Washington (Apr. 14, 2026)	
103-1	Air Discharge Permit Application	Tetra Tech, *Air Discharge Permit Application, TransAlta Centralia Generation, LLC* (Jan. 2026)	
103-2	Completeness determination for air discharge permit application	Letter from Southwest Clean Air Agency to TransAlta Centralia Generation *re: Completeness Determination for Air Discharge Permit Application L-760* (Feb. 25, 2026)	
104	Second Moriyasu Declaration	Declaration of Callahan Moriyasu in Support of Second Rehearing Filing (Apr. 13, 2026)	

No.	Exhibit Name	Document Name	URL
105	Lim Declaration	Declaration of Mengchiu Lim in Support of Motion to Intervene, Request for Rehearing and Motion to Stay by State of Washington (Apr. 14, 2026)	
105-1	TransAlta PSD Permit Application	Tetra Tech, *Prevention of Significant Deterioration Permit Application, TransAlta Centralia Generation, LLC, Lewis County, Washington* (Dec. 2025)	
105-2	Ecology Incom-pleteness Letter	Letter from Dep't of Ecology to TransAlta Centralia Generation, LLC– *Incompleteness Letter for the TransAlta Centralia Plant Project* (Jan. 23, 2026)	
105-3	TransAlta Incom-pleteness Letter Response	Letter from TransAlta to Dep't of Ecology re: *Incompleteness Letter Response for the TransAlta Centralia Plant Project* (Mar. 10, 2026)	

No.	Exhibit Name	Document Name	URL
106	NERC LTRA	North American Electric Reliability Corporation, *Long-Term Reliability Assessment* (Jan. 2026)	https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
107	Kumar Declaration	Declaration of Nikhil Kumar in Support of Motion to Intervene, Request for Rehearing, and Motion to Stay by State of Washington (Apr. 13, 2026)	
107-1	Sylvan Analytics Review of E3 Report	Sylvan Energy Analytics, *Near-term winter resource adequacy challenges in the Pacific Northwest, A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges* (Jan. 2026)	
107-2	Koomey Analytics Data Center Forecasts	Koomey Analytics, *Separating Fact from Fiction in Data Center Electricity Forecasts, A Guide for Regulators* (Mar. 2026)	

No.	Exhibit Name	Document Name	URL
107-3	Brattle Report	Levitt, Pfeifenberger, Mohan, Patel (Brattle), *Proposed Options for Bilateral Integration of Generation Portfolios and Load (BIGPAL)* (Sep. 26, 2025)	
107-4	NERC to Dial Down RTO's Risk Level	Cook, RTO Insider, *MISO: NERC to Dial Down RTO's Risk Level; Members Create Large Load Working Group* (Mar. 25, 2026)	
108	GridStrategies Report	GridStrategies, *Review of NERC's 2025 Long-Term Reliability Assessment* (Mar. 5, 2026)	https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf
109	Carvallo Report	Carvallo, Larsen, Sanstad, Goldman, Berkeley National Laboratory, *Load Forecasting in Electric Utility Integrated Resource Planning* (Oct. 2016)	https://eta-publications.lbl.gov/sites/default/files/lbnl-1006395.pdf
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No.	Exhibit Name	Document Name	URL
111	UTC Notice of Hybrid Technical Conference	Utilities and Transportation Commission, *Notice of Hybrid Technical Conference* (Apr. 7, 2026)	https://www.utc.wa.gov/casedocket/2026/260162/docsets
112	NERC Statement on LTRA	North American Electric Reliability Corp., *Statement on NERC's 2024 Long-Term Reliability Assessment* (Jun. 25, 2025)	https://www.nerc.com/newsroom/statement-on-nercs-2024-long-term-reliability-assessment
113	NERC Comments on Large Load	Before the Federal Energy Regulatory Commission, Docket No. RM26-4-000, *Comments of the North American Electric Reliability Corporation in Response to Notice Inviting Comments* (Nov. 21, 2025)	https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2025/large_load_anopr_comments_final_digicert.pdf
114-1	Nat'l Wildlife Fed'n v. NMFS Injunction	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Amended Preliminary Injunction Order* (Mar. 2, 2026)	

No.	Exhibit Name	Document Name	URL
114-2	Nat'l Wildlife Fed'n v. NMFS Order	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Amended Order Granting Preliminary Injunction* (Mar. 2, 2026)	
115	Dibble Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Rachel Dibble in Support of Federal Defendants' Opposition to Plaintiffs' Motions for a Preliminary Injunction* (Dec. 12, 2025)	
116	Stevenson Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Audrey Stevenson in Support of Federal Defendants' Opposition to Plaintiffs' Motions for a Preliminary Injunction* (Dec. 11, 2025)	

No.	Exhibit Name	Document Name	URL
117	Hirsch Decl.	U.S. Dist. Court, Dist. of Oregon, Case No. 3:01-cv-640-SI, *Declaration of Nancy Hirsh in Support of Plaintiffs' Reply in Support of Motion for Preliminary Injunction* (Jan. 22, 2026)	
118	BPA FOIA Response	Dep't of Energy, Bonneville Power Administration Letter to Megan Sallomi, Wash. Attorney General's Office, EPA Division, *Response to Request for Agency Records via FOIA* (Feb. 19, 2026)	
119	US EIA Outlook	Short-Term Energy Outlook, April 7, 2026	https://www.eia.gov/outlooks/steo/report/elec_coal_renew.php
Centralia III			
120	Order No. 202-26-28	Dep't of Energy, *Order No. 202-26-28* (Jun. 12, 2026)	
121	May Campbell Order	Dep't of Energy, *Order* No. 202-26-22 (May 19, 2026)	

No.	Exhibit Name	Document Name	URL
122	May Eddystone Order	Dep't of Energy, *Order* No. 202-26-24 (May 21, 2026)	
123	December Craig Order	Dep't of Energy, *Order* No. 202-25-14 (Dec. 30, 2025)	
124	March Craig Order	Dep't of Energy, *Order* No. 202-26-21 (Mar. 30, 2026)	
125	June Craig Order	Dep't of Energy, *Order* No. 202-26-31 (Jun. 26, 2026)	
126	March Culley Order	Dep't of Energy, *Order* No. 202-26-20 (Mar. 23, 2026)	
127	June Culley Order	Dep't of Energy, *Order* No. 202-26-30 (Jun. 18, 2026)	
128	December Schahfer Order	Dep't of Energy, *Order* No. 202-25-12 (Dec. 23, 2025)	
129	March Schahfer Order	Dep't of Energy, *Order* No. 202-26-19 (Mar. 23, 2026)	
130	June Schahfer Order	Dep't of Energy, *Order* No. 202-26-29 (Jun. 18, 2026)	

No.	Exhibit Name	Document Name	URL
131	Third Moriyasu Decl.	Third Declaration of Callahan Moriyasu	
131-1	NERC 2026 SRA	North American Electric Reliability Corporation, 2026 Summer Reliability Assessment (May 2026)	
131-2	Joint IOU Presentation Meeting Slides	WUTC Summer 2026 Resource Adequacy Meeting, Summer 2026 Readiness: A Joint IOU Presentation (Jun. 13, 2026)	
131-3	Resource Adequacy Requirements	The Brattle Group, *Resource Adequacy Requirements: Reliability and Economic Implications* (Sept. 2013)	
131-4	NERC 2025 SRA	North American Electric Reliability Corporation, 2025 Summer Reliability Assessment (May 2025)	
131-5	Grid Strategies Review of LTRA	Review of NERC's 2025 Long-Term Reliability Assessment (Jun. 22, 2026)	

No.	Exhibit Name	Document Name	URL
131-6	Full Report Grid Strategies Review of LTRA	Review of NERC's 2025 Long-Term Reliability Assessment (Mar. 5, 2026)	
131-7	PSE Response to WUTC	PSE Response to WUTC Staff Data Request No. 008 (Apr. 6, 2026)	
131-8	Sylvan June 22, 2026 WA RA Meeting Slides	Sylvan Energy Analytics, GridLab, *Near-term winter resource adequacy challenges in the Pacific Northwest, A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges* (Jun. 22, 2026)	
132	December Culley Order	Dep't of Energy, *Order* No. 202-25-13 (Dec. 23, 2025)	

EXHIBIT 137

AMERICA'S POWER
Reliable • Secure • Resilient • Affordable

March 11, 2025

The Honorable Chris Wright
Secretary
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Secretary Wright:

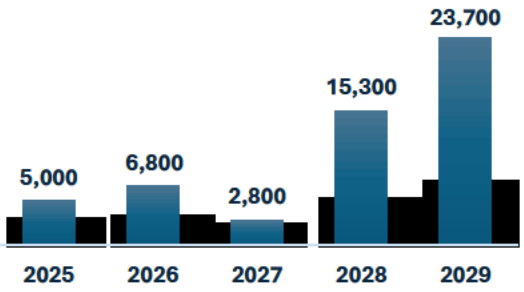
I am writing on behalf of America's Power to seek assistance from the Department of Energy (DOE) in preventing the retirement of more coal-fired electric generating units. America's Power is the only national trade association whose sole mission is to advocate for the nation's coal fleet, which totals 370 electric generating units that represent approximately 175,000 megawatts (MW) of generating capacity. Our membership is comprised of electricity generators, coal producers, equipment manufacturers, and companies that transport coal (collectively, the coal supply chain).

As you know, the nation's coal fleet and a healthy supply chain are essential to maintaining a reliable, affordable, and resilient electricity supply. The coal fleet provides essential reliability services, helps stabilize electricity prices, provides energy security, possesses a high capacity value, has demonstrated its resilience during extreme weather, and is capable of providing substantial amounts of electricity to meet exploding electricity demand.

We commend President Trump for issuing the Executive Order "Declaring a National Energy Emergency" (EO) that calls attention to our nation's "inadequate energy supply," an "increasingly unreliable grid," and the need for "swift and decisive action" to remedy these problems. Premature coal retirements are one of the major reasons for this energy emergency. The following facts show the gravity of the situation:

- Forty (40) percent of the nation's coal fleet (769 generating units totaling 141,000 MW) has retired since 2010. Of this total, 43,300 MW (137 units) retired during 2020-2024.
- Electricity generators have announced plans to retire an additional 53,600 MW of coal (118 generating units) during 2025-2029. Retirements increase dramatically in 2028 and 2029 (chart).

Nationwide Announced Coal Retirements (MW)
During the Next 5 Years



- This is the same 5-year period during which the North American Electric Reliability Corporation's (NERC) Long-Term Reliability Assessment (December 2024) projects that half the U.S. will be at either "high" or "elevated" risk of electricity shortages.
- The bulk of announced coal retirements – 52 generating units totaling more than 31,000 MW – will occur over the next 5 years in three regions: MISO ("high" risk of shortages), PJM ("elevated" risk of shortages), and SPP ("elevated" risk of shortages).
- Recognizing their urgent need for coal-fired generation, utilities have announced plans to delay 26,000 MW of coal retirements primarily because of load growth and reliability concerns. (These are excluded from the retirement numbers above.) These delayed retirements are necessary but obviously not sufficient to prevent a national energy emergency from continuing.

Repealing or rewriting a number of EPA regulations could reverse some of these announced retirements. However, these regulations must be repealed as quickly as possible to prevent electricity generators from being forced to make irreversible compliance decisions that could lead to even more premature coal retirements.

Besides regulatory reforms, some form of economic support is also essential to preserve coal-fired generation. For example, the General Services Administration entered into a contract in January 2025 to purchase 10 million megawatt-hours of nuclear power over a period of 10 years. A similar arrangement to purchase coal-fired electricity would provide much needed support to the coal fleet and would be consistent with the mandate in the EO to remedy the vulnerabilities resulting from inadequate energy and electricity.

In addition, a DOE order pursuant to Section 202(c) of the Federal Power Act (FPA) could prevent the premature retirement of certain coal units. Section 202(c) provides that:

> [W]henever the [Secretary of Energy] determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy … the [Secretary of Energy] shall have authority … to require by order such temporary connections of facilities and generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest.

DOE has issued Section 202(c) orders and extensions of orders more than 20 times since 2000. While most of these orders were issued for only a few days due to extreme weather, Section 202(c) allows the Secretary of Energy to direct the continued operation of specific coal units for longer periods of time as well as to mandate payments to ensure their availability because of national security risks or the resource adequacy risks identified in NERC's annual Long-Term Reliability Assessments such as the one mentioned above.

In addition, DOE could act pursuant to Section 101(a) and (c) of the Defense Production Act (DPA) because of the need for adequate power supplies to promote the national defense. Contracts that preserve the coal supply chain for national defense purposes are justified under the DPA as well.

The EO directs agencies and departments and agencies to "identify and exercise any lawful emergency authorities available to them …." We believe that use of the authorities above is consistent with this directive. We would welcome the opportunity to discuss these and other potential solutions with you.

In the meantime, please contact me at [redacted] or Paul Bailey at [redacted] if you or your staff have any questions.

Sincerely,



Michelle Bloodworth
President and CEO

Copy to:

The Honorable Steve Winberg
Under Secretary for Infrastructure

EXHIBIT 138

The New York Times https://www.nytimes.com/2026/09/28/climate/coal-industry-power-plants-trump.html

The Coal Industry Asked for a Rescue. Trump Obliged.

In a previously unreported letter, a top lobbyist floated the idea of using emergency powers to keep aging coal plants open.

Listen · 10:17 min




By Brad Plumer and Claire Brown
Brad Plumer reported from Washington and Claire Brown from New York.

Sept. 28, 2026

Early last year, a top coal lobbyist sent a letter to Energy Secretary Chris Wright with a dire warning.

Roughly one-third of the nation's coal-burning power plants were scheduled to close within five years, according to the letter, dated Mar. 11, 2025, from a coal trade group. Many of the closures would occur during President Trump's second term.

But what if the plants didn't have to shut down? The trade group, America's Power, proposed an unusual remedy: The Energy Department could deploy rarely used emergency powers to force them to stay open longer.

Two months later, the Trump administration began doing exactly that.

The letter, which has not been previously reported, reveals some of the earliest known discussions about a move that experts have called an extraordinary intervention into the nation's energy markets.

Since May 2025, the Energy Department has repeatedly issued emergency orders to keep nine coal-burning units at six plants operating long past their scheduled retirement dates, saying the facilities are needed to prevent looming blackouts. The orders have sometimes come over the protests of the plant's owners and are expected to cost ratepayers hundreds of millions of dollars. A federal appeals court has already struck down one order, ruling that it overstepped the law.

The letter from America's Power was made public through a Freedom of Information Act request by the Environmental Defense Fund, an environmental group.

Mr. Trump has long expressed his affection for the coal industry, often calling it "clean, beautiful coal" to needle environmentalists, who point out that the highly polluting fuel is a major driver of global warming.

Coal power has been declining for two decades, as utilities have retired hundreds of older plants in favor of cheaper and cleaner natural gas, wind and solar power. Even Mr. Trump couldn't stop the slide in his first term. More than 150 coal-burning units shut down between 2017 and 2020.

In the letter last year, Michelle Bloodworth, the chief executive of America's Power, laid out several ideas to reverse the trend. The Environmental Protection Agency could repeal costly pollution rules, she wrote. The federal government could purchase power directly from coal plants. The administration could invoke a Korean War-era law called the Defense Production Act to inject fresh funding into coal supply chains.

Most immediately, the Energy Department could keep coal plants open under Section 202(c) of the Federal Power Act, a provision that historically has been used only sparingly during temporary emergencies such as hurricanes. The emergency in this case, the letter said, was an expected shortage of reliable power over the next decade, citing forecasts from a leading grid monitor.

The Trump administration has since taken each of those steps. In July, Lee Zeldin, administrator of the E.P.A., told coal executives at a public meeting, "Many of the items that were on your wish list are now done."



Energy Secretary Chris Wright, center, a few steps in front of Interior Secretary Doug Burgum. Doug Mills/The New York Times

“The letter shows the really broad extent to which the coal industry is not only influencing but even directing the Trump administration’s actions,” said Ted Kelly, director and lead counsel for U.S. clean energy at the Environmental Defense Fund. “The industry swung for the fences and got everything they asked for.”

In a statement, Ms. Bloodworth said keeping older coal plants online was necessary to prevent electricity shortages as demand surges.

“We appreciate Secretary Wright and the Trump administration for using the emergency authority Congress provided under Section 202(c) of the Federal Power Act,” she said. “It is one of the few tools available to protect grid reliability at a moment when electricity demand is climbing faster than new generation can be built.”

“Federal and state officials must work together to prevent the premature retirement of dependable coal generation,” she said. “Waiting for a blackout before taking action is an unacceptable gamble.”

America’s Power does not publish a list of members but says it represents coal producers and electricity generators.

While an Ohio-based utility briefly proposed using emergency powers to stop coal plants from retiring in 2018, the idea never gained traction and was rarely discussed later. It wasn’t mentioned in Project 2025, the conservative policy blueprint for a second Trump term.

Asked whether the coal industry letter had inspired the Energy Department’s actions, Ben Dietderich, an agency spokesman, said, “No. On day one, President Trump declared a national energy emergency due partly to past leaders’ energy subtraction policies that encouraged the premature shutdown of reliable coal and natural gas plants.”

It is not unusual for industry groups to send wish lists to incoming presidents. In 2020, shortly before President Joseph R. Biden, Jr., took office, the solar and wind industries published numerous recommendations, such as having the federal government buy renewable energy, that the Biden administration later adopted.

But the Trump administration’s use of emergency powers to keep coal plants open has created significant friction.

In some cases, the orders have surprised utilities, arriving at the last minute and upending months of preparation for closure. Some companies have scrambled to replenish their coal piles, bring back workers and quickly make repairs, spending tens of millions of dollars in the process. Each order lasts only for 90 days, but the Energy Department has repeatedly renewed them.

One operator, CenterPoint Energy, asked the Energy Department in February to let an emergency order lapse for the Culley coal plant in Warrick County, Ind., saying that running the unit would require up to $18 million in repairs. The department has since renewed its order three times.

The operators of the Craig Generating Station in Colorado went a step further, challenging their emergency order and explicitly saying that the coal unit was not needed.

Another utility, the Northern Indiana Public Service Company, has asked regulators to let it collect at least $38 million from customers to cover the costs of keeping open two aging coal units at its Schahfer plant. One unit has been out of commission since July 2025 because of a turbine failure and will require extensive repairs, the company said in public filings. The other ran during the winter before going offline in March for maintenance.

“The orders are forcing the utility owner to throw money at uneconomic plants that were rightly taken out of service,” said Ari Peskoe, director of Harvard Law School’s Electricity Law Initiative.

Mr. Wright, the energy secretary, has called the orders a necessary corrective after Democratic administrations and states hurt the coal industry by imposing strict environmental rules on power plants, often in the name of tackling climate change.

“Coal is massively more important for the U.S. electricity grid than wind and solar combined today,” Mr. Wright said last week at The New York Times’s Climate Forward event. “And coal has had a war on it. The government has imposed heaps of costs on it, regulatory burdens, everything to strangle it.”

Wind and solar power combined generated more electricity in the United States than coal last year, but coal can run on demand at all hours while wind turbines and solar panels cannot.

Without orders to stop coal plants from retiring, Mr. Wright added, “we would have had hundreds of Americans freeze to death in the last week of January last year.” He also said that some utilities have requested federal help to keep plants open.

Environmental groups have disputed those claims, arguing that the Midwestern regional grid — where several coal plants have been required to stay open — had sufficient capacity available during peak demand periods last winter and this summer.



E.P.A. administrator Lee Zeldin speaks in the Oval Office. At another meeting, Mr. Zeldin told coal executives, “Many of the items that were on your wish list are now done.” Tom Brenner for The New York Times

The coal industry continues to struggle even as electricity demand grows, particularly from A.I. data centers. During the 2000s, coal provided nearly half of the nation’s electricity. But that share was just 17 percent last year and is expected to decline sharply again this year, according to federal data.

The Energy Department’s orders have also faced legal pushback. This month, a three-judge panel at the U.S. Court of Appeals for the District of Columbia Circuit struck down the first such order, to keep the J.H. Campbell coal plant in West Olive, Mich., operating.

The court ruled that the agency had overstepped its authority. It said states have responsibility to manage power generation and that the federal government should intervene only when states and grid operators can’t or won’t respond.

Since that ruling, however, the Energy Department has renewed orders to keep coal units running in Indiana, Colorado and Washington.

“The Energy Department disagrees with the decision and is working with the Department of Justice to assess potential rehearing and appeal options,” said Mr. Dietderich, the agency spokesman.

In Michigan, the owner of the J.H. Campbell plant has said it would keep the facility running since the court struck down only the first three-month emergency order. The agency has since issued five more. But environmentalists and other legal experts said the decision undercut the rationale for all such orders.

“In our view, the next move should be for D.O.E. to stand down, but as we see with this administration, it is often reluctant to stand down,” said Sanjay Narayan, managing attorney at the Sierra Club.

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

Claire Brown covers climate change for The Times and writes for the Climate Forward newsletter.

A version of this article appears in print on , Section A, Page 16 of the New York edition with the headline: The Coal Industry Sought a Pricey Bailout. The White House Obliged.

EXHIBIT 139

Department of Energy
Washington, DC 20585

Consumers Energy Company and
Midcontinent Independent System Operator, Inc.
Regarding J.H. Campbell Generating Plant

Order No. 202-26-39

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midcontinent Independent System Operator, Inc. (MISO) region due to a sudden increase in demand or a shortage of electric energy or facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, February 17, 2026, May 18, 2026, and August 16, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the region served by MISO.

Specifically, I determined that MISO likely faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-9, at 1 (Nov. 18, 2025).

these periods, which would help prevent the potential loss of power to homes and businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6]

My determination was based on a number of facts. First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "Michigan's nuclear power plants typically supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural

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[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] N. Am. Elec. Reliability Corp., *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id*.

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id*.

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

gas power plant in Covert, Michigan, NERC has noted that "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2026–2027 Planning Year, released in April 2026, notes that "capacity additions need to continue, given expected growth from new large loads."[13] Further, MISO reiterates that "while our market reforms have helped hold the line amidst tighter reserve margin compared to the prior decade, resource adequacy remains at risk, especially as demand for large load additions accelerate."[14]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22 continue, both in the near and long term.[15] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for May 2026, the total net generation for the Campbell Plant was 1,431,336 MWh from January 2026 to May 2026 for an average of 286,267 MWh per month.[16] The historic data of consistent generation indicates the Campbell plant is providing vital generation capacity to the region. From June 11, 2025, through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its

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[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC *LTRA*].

[13] MISO, *Planning Res. Auction Results for Planning Year 2026/27*, at 3 (Apr. 2026) (Updated May 22, 2026) (MISO 2026–2027 Planning Resource Auction), https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf.

[14] *Id.* at 7.

[15] It likely would be difficult for a coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Consumers was to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[16] *See* EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 May 2026").

Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[17]

MISO's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[18]

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[19] MISO justified this revision by explaining that "[r]eliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[20] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[21]

In December 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[22] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[23] MISO also projected that the risk of loss of load in the winter

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[17] MISO, *Operations Rep.* (Sept. 16, 2025), https://cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf.

[18] MISO, *Operations Rep.*, at 10 (Mar. 24, 2026), https://cdn.misoenergy.org/20260324%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20MISO%20Operations%20Report746763.pdf.

[19] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[20] MISO Transmittal Letter at 3.

[21] *Id.* at 3–4.

[22] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[23] *Id.* at 11.

and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[24]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[25] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[26]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment (LTRA).[27] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC LTRA notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[33]

The 2025–2026 NERC Winter Reliability Assessment (WRA) found the MISO region to be at normal risk in 2026 and elevated risk in 2027. The two previous winter

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[24] *Id.*

[25] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[26] *Id.* at 12.

[27] *See* NERC *LTRA*, *supra* note 12.

[28] *Id.* at 6, 8.

[29] *Id.* at 8.

[30] *Id.* at 43.

[31] *Id.* at 15.

[32] *Id.*

[33] *Id.*

studies respectively characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions"[34] and noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

NERC released its 2026 Summer Reliability Assessment (SRA) on May 19, 2026. In its assessment, NERC stated that "MISO's peak load has increased by 2.5 GW from the 2025 SRA."[36] The 2026 SRA also projects that data center load will continue to accelerate in 2027 and beyond, potentially increasing reliability risk if capacity additions do not keep pace.[37] Furthermore, the 2026 SRA states that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations . . . and EEAs."[38]

There continues to be tight capacity available during summer despite the recent "gains in offered capacity outpacing pressure of load growth" in the MISO region, as reported in its PRA for the 2026-2027 Planning Year.[39] MISO noted that "new generation capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy."[40]

On June 4, 2026, the Organization of MISO States (OMS) and MISO issued the results of their 2026 survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[41] The 2026 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years and states "growth as submitted by [load serving entities or LSEs] continues to accelerate, with a [compound annual growth rate or CAGR] projected between 3.1% and 5.1% over [the next] five years."[42]

The OMS-MISO Survey further indicates that "[v]arious projected capacity scenarios and large load additions highlight increasing uncertainty and evolving risk"[43]

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[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[36] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[37] *Id.*

[38] *Id.*

[39] MISO 2026–2027 Planning Resource Auction at 3.

[40] *Id.* at 2.

[41] OMS & MISO, *OMS-MISO Survey Results* (updated June 4, 2026) (2026 OMS-MISO Survey), https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf.

[42] *Id.* at 2.

[43] *Id.* at 3.

and observes various negative risks. Examples include intensification of winter reliability risks based on resource availability/performance, which exacerbates seasonal reliability vulnerabilities; delay of new resource deployment owing to persistent supply-chain disruptions, labor constraints and permitting challenges; resource adequacy pressures continuing from load growth driven by data centers, new industrial, and commercial development; and continued backlog and uncertainty related to resources with signed Generator Interconnection Agreements (GIA).[44] In addition, 87 GW of signed GIAs are not yet online, and 192 GW of active GIAs still under study.[45]

Finally, the OMS-MISO Survey lists ongoing challenges such as more frequent extreme weather; accelerating demand for electricity and large load interconnections; loss of accredited capacity and reliability attributes as resource mixes evolve; the increasing pace of new resources additions; addressing local reliability issues (load pocket); and evolving storage participation.[46]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[47] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[48] Finally, data in the SOR shows that 2025 MISO summer and winter peak demands of 121.6 GW and 108.8 GW, respectively, met or exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a real risk in MISO.[49]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[50] MISO's ERAS should help expedite the construction of needed new capacity; however, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial

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[44] *Id.* at 4.

[45] *Id.*

[46] *Id.* at 16.

[47] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[48] *Id.* at vii.

[49] *Id.* at 28, 30.

[50] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

operations.[51] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[52] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[53] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[54] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[55]

In addition, President Trump issued a White House Memo to the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . [w]ithout sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as

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[51] NERC, *State of Reliability*, *supra* note 48, at 84.

[52] *See generally* Jared Anderson, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P GLOBAL (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[53] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[54] *Id.*

[55] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

artificial intelligence."[56] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[57]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[58] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[59] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[60]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, MISO's Senior Vice President for Planning and Operations, Jennifer Curran, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[61] Ms. Curran also described "much stronger growth [in demand

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[56] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity"), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[57] *Id.*

[58] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[59] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* , INVEN (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[60] *See* Zachary Skidmore, *Mich. util. Consumers Energy to provide 1GW of power to new hyperscale data center*, DATA CENTER DYNAMICS (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[61] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President

for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[62] She added, "A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[63]

Pursuant to section 202(c)(4)(B) of the FPA, DOE has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[64] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Campbell Plant will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), the Campbell Plant shall be made available for operation through November 14, 2026.[65]

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for Planning and Operations, MISO), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[62] *Id.* at 6.

[63] *Id.* at 7.

[64] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[65] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with this Order.

C. All operations of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By August 31, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

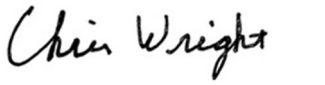
E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective on August 17, 2026, through November 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 14th day of August 2026.



Chris Wright
Secretary of Energy

cc:

Federal Energy Regulatory Commission
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commission
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

EXHIBIT 140

Department of Energy
Washington, DC 20585

Constellation Energy Corp. and
PJM Interconnection, L.L.C.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-40

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region of the, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, February 24, 2026, May 24, 2026, and August 22, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the PJM region.

Specifically, I determined that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.[5]

My determination was based on a number of different facts. First, in congressional testimony, PJM's then President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-26-24, at 10 (May 21, 2026).
[4] *Id.* at 9.
[5] *Id.* at 9 & Ordering Para. A.

resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

Fourth, PJM's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric

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[6] *Keeping the Lights On: Examining the State of Reg'l Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) ("PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] *PJM Summer Outlook 2025: Adequate Res. Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter *Four Rs Report*], https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[11] DOE granted PJM's application and issued Order No. 202-26-02 on January 25, 2026.[12] From January 27, 2026, until early February 2026, PJM issued multiple alerts and warnings.[13]

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.[14] Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that "PJM and other grid operators indicated that 202(c) facilities made material contributions" with regard to reliability during Winter Storm Fern.[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 continue, both in the near and long term.[16] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S.

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[11] Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec'y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

[12] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[13] *See PJM Interconnection, L.L.C., Emergency Procedures—Postings, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf; see, e.g., Jan. 27 PJM Cold Weather Operations Update*, PJM INSIDE LINES (Jan. 27, 2026), https://insidelines.pjm.com/jan-26-pjm-cold-weather-operations-update/.

[14] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[15] *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf.

[16] Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a power plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. *See*, *e.g.*, Lessick, Jennifer et al. *Bus. Models for Coal Plant Decommissioning* § 4, PAC. NW. NAT'L LAB'Y (Aug. 2021), https://www.osti.gov/servlets/purl/1821476.

Environmental Protection Agency (EPA), the Eddystone Units generated 27,239 MWh between August 2025 and March 2026,[17], providing vital generation capacity to the region. Over the summer of 2025, PJM issued multiple alerts and warnings to manage grid operations and reliability, covering a total of 20 days, including days in June, July, and August.[18] Similar actions have occurred already for summer 2026. In May, June, and July, PJM requested emergency orders for backup and non-backup generators due to high temperatures resulting in high demand forecasts, causing potential reliability issues. This resulted in the issuance of several emergency orders, namely, DOE Order Nos. 202-26-23, 202-26-24, 202-26-32, 202-26-32A, 202-26-33, 202-26-33A, and 202-26-35, with the last one ending at midnight of July 21, 2026.[19] These emergency orders helped PJM manage high demand, including an instantaneous peak demand of 162.7 GW on July 2, 2026, that was higher than PJM's previously forecasted peak summer demand of 156.4 GW.[20]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[21] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[22] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025

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[17] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Eddystone Generating Station (3161)"; then click "Eddystone Generating Station (3161)"; then click "Apply Filter"; then click "Preview Data"; then change the "Time Period" to "2026" and click "January, February, March"; then click "Apply Filter"; then click "Preview Data").

[18] *See* PJM, *Emergency Procs.*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search Effective From 06/01/2025 Effective To 08/31/2025).

[19] *See 2026 DOE 202(c) Orders*, Department of Energy, https://www.energy.gov/ceser/2026-doe-202c-orders.

[20] Penn. Pub. Util. Comm'n, *Summer 2026 PJM Reliability Assessment*, at 5 (May 2026), https://www.puc.pa.gov/media/3965/2026_pjm_summer_readiness_report.pdf. *See also PJM Hot Weather Operations Update: July 3*, PJM INSIDE LINES (July 3, 2026), https://insidelines.pjm.com/pjm-hot-weather-operations-update-july-3/.

[21] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec. Demand*, PJM INSIDE LINES (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[22] *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[23]

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that "[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that KEY-CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028."[24]

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that "[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home."[25] Furthermore, PJM expressed support for Order No. 202-25-04, since it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[26]

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[23] PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[24] COMMONWEALTH OF PENN., DEP'T OF ENV'T PROT. V. KEYSTONE-CONEMAUGH PROJECTS, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf.

[25] Kate Huangpu, *How Josh Shapiro wants to reshape the region's power grid operator as prices rise*, SPOTLIGHT PA (Oct. 14, 2025), https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/.

[26] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint." *Id*.

PJM has voiced these concerns for years. In its February 2023 *Four Rs Report*, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[27] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.[28] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[29] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[30]

In its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report."[31] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[32] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[33] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[34] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[35]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director of Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[36] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme"

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[27] *Four Rs Report*, *supra* note 9, at 2.

[28] *Id*.

[29] *Id.* at 16 tbl. 1.

[30] *Id*.

[31] PJM, Filing, Dkt. No. ER25-712-000, at 10 (filed Dec. 13, 2024).

[32] *Id*.

[33] *Id.* at 10–11; *see also id.* at 13 (stating that "the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements").

[34] *Id.* at 14.

[35] *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner").

[36] Bielak Aff. at 10.

forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[37]

On February 11, 2025, FERC accepted PJM's proposed tariff revisions in its RRI filing.[38] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[39]

NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years[40] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[41] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads"; however, "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[42] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[43]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding."[44] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[45] Finally, data in the SOR shows that 2025 PJM summer peak demand of 160.7 GW met or

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[37] *Id.*at 12.

[38] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g.*, *id.* P 263.

[39] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[40] NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[41] *Id.* at 8.

[42] *Id.* at 16.

[43] *Id.* at 91.

[44] NERC, 2026 State of Reliability Technical Assessment of 2025 Bulk Power System Performance, at 5 (June 2026), https://nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[45] *Id.* at vii.

exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a risk in PJM.[46]

DOE Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[47] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[48] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[49]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[50] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[51] As of December 2024, Dominion Energy has 40.2 GW

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[46] *Id.* at 30.

[47] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[48] *Id*.

[49] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[50] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[51] *See* PPL Corp., *PPL Corp. Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[52] In collaboration with the national labs, the Department has modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[53] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[54]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. As mentioned earlier in this Order, PJM's then President Manu Astana testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[55] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[56] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[57] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[58]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the

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[52] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

[53] Resource Adequacy Report, *supra* note 50, at 28.

[54] *Id.* at 27.

[55] Asthana Test., *supra* note 6, at 4.

[56] *Id*.

[57] *Id.* at 9–10.

[58] *Id.* at 10.

emergency and serve the public interest."[59] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from the increasing demand and shortage of electric energy from premature retirements of Eddystone Units will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or outages, presenting a risk to public health, safety, and security.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), the Eddystone Units shall be made available for operation through November 20, 2026.[60]

[59] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[60] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 23, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operations of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By September 8, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resource.

H. This Order shall be effective on August 23, 2026, through November 20, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of August 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc:

Federal Energy Regulatory Commission
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commission
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora