

EXHIBIT 131

1
2
3 UNITED STATES OF AMERICA
4 BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

5 Federal Power Act Section 202(c)
6 Emergency Order TransAlta
7 Centralia Generation

Order No. 202-26-28

8
9 **THIRD DECLARATION OF CALLAHAN MORIYASU**
10 **ON BEHALF OF**
11 **THE WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL**

12 **Background and Qualifications**

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

23 **Purpose of This Affidavit**

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

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.

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

19 **Additional Research Indicates that NERC’s 2025 Long-Term Reliability Assessment**
20 **Makes Overly Conservative and Unrealistic Assumptions that Overstate Resource**
21 **Adequacy Risk**

22 5. Centralia III also cites NERC’s 2025 Long-Term Reliability Assessment
23 (LTRA), quoting the WECC-NW region’s “high risk of energy shortfalls over the next five
24 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.

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

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

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

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

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

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

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

25 _____
26 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 Seattle³ and Spokane⁴, as well as the counties of Skagit⁵ and Snohomish⁶.

13. Additional states in WECC-NW have also implemented or proposed data center moratoriums. Oregon passed a one-year moratorium on data center tax breaks⁷, Idaho passed a law imposing restrictions on data center water usage⁸ 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>.

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

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

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

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

18 18. PSE stated that it has the resources to "meet our WRAP capacity targets," added
19 250 MW of capacity since last year, and increased its demand response programs to 61 MW.
20 Ex. 131-2 at 3.

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

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

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

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

5 DATED this 9 day of July 2026, in Seattle, Washington.
6

7 Callahan Moriyasu
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9 CALLAHAN MORIYASU
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¹¹https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/GRID?utm_source=chatgpt.com

EXHIBIT 131-1

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

POWERING TODAY. PROTECTING TOMORROW.

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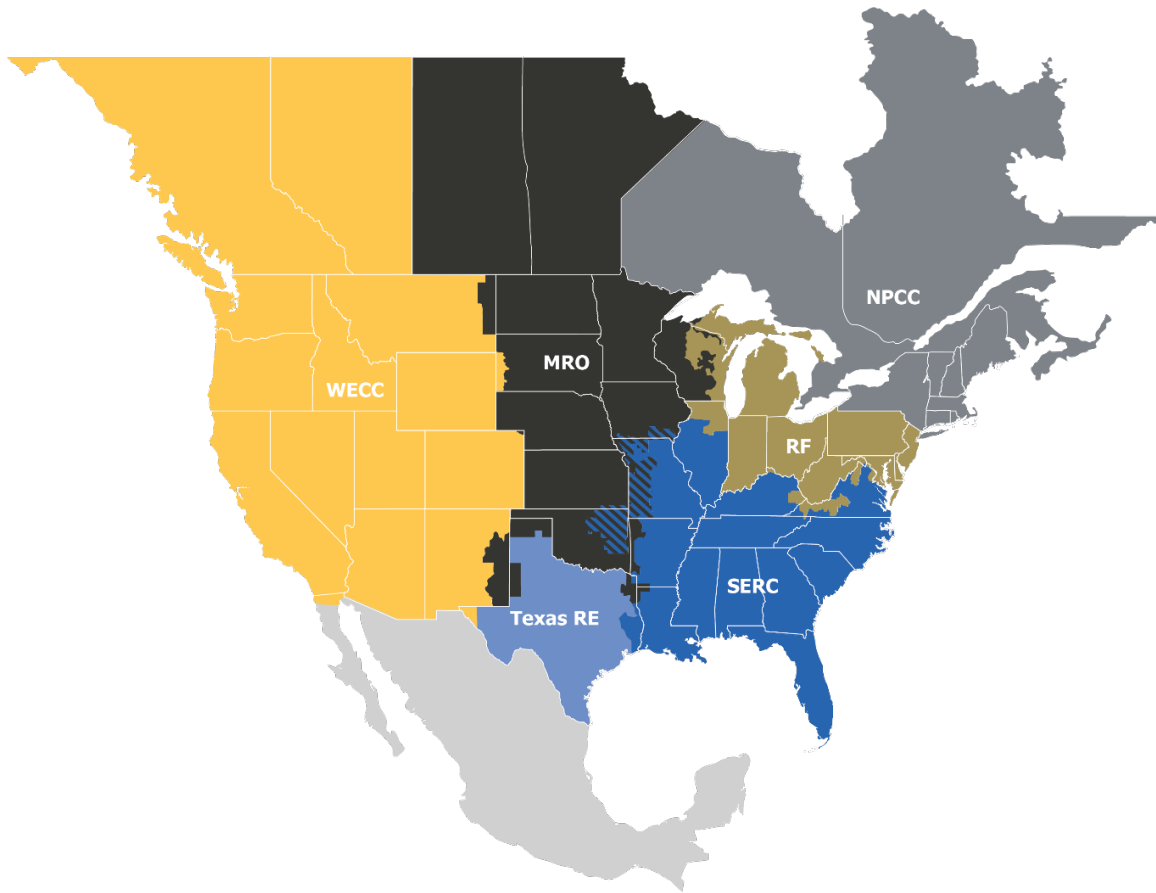
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Preface

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](#).

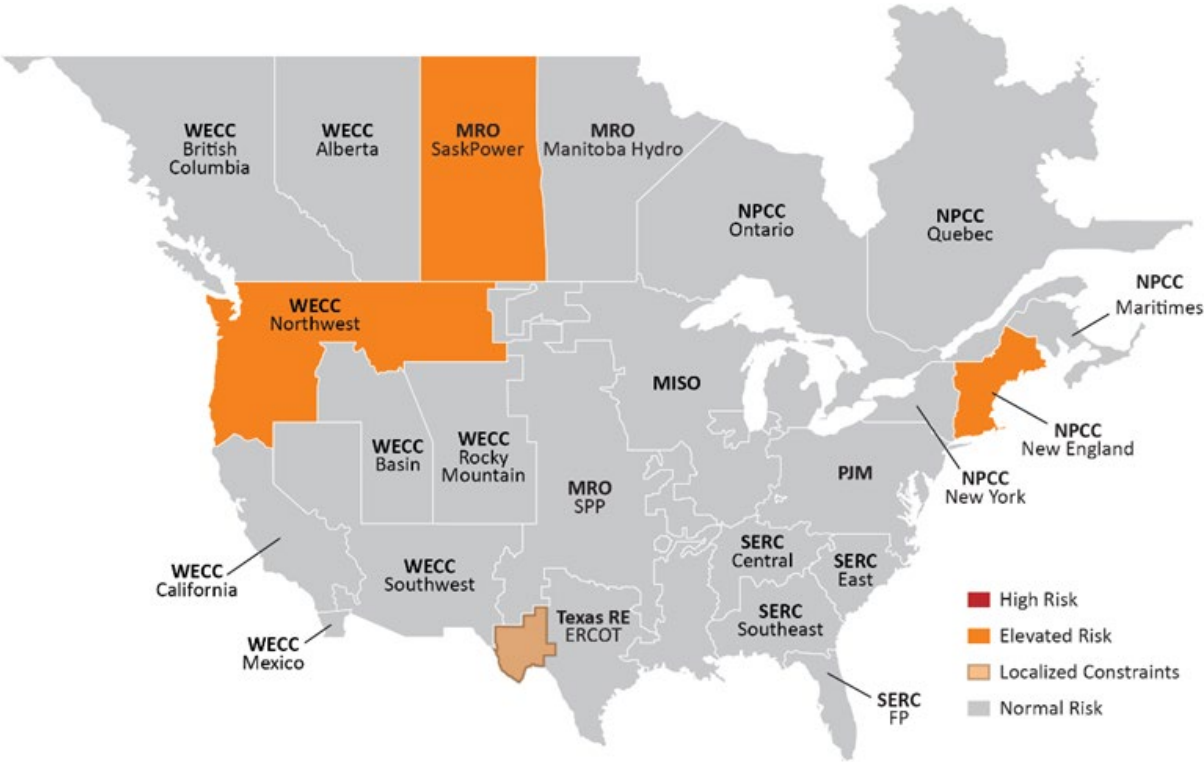
Resource Adequacy Assessment and Energy Risk Analysis

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 snowpack⁵ 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 of 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 loads⁷ 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.

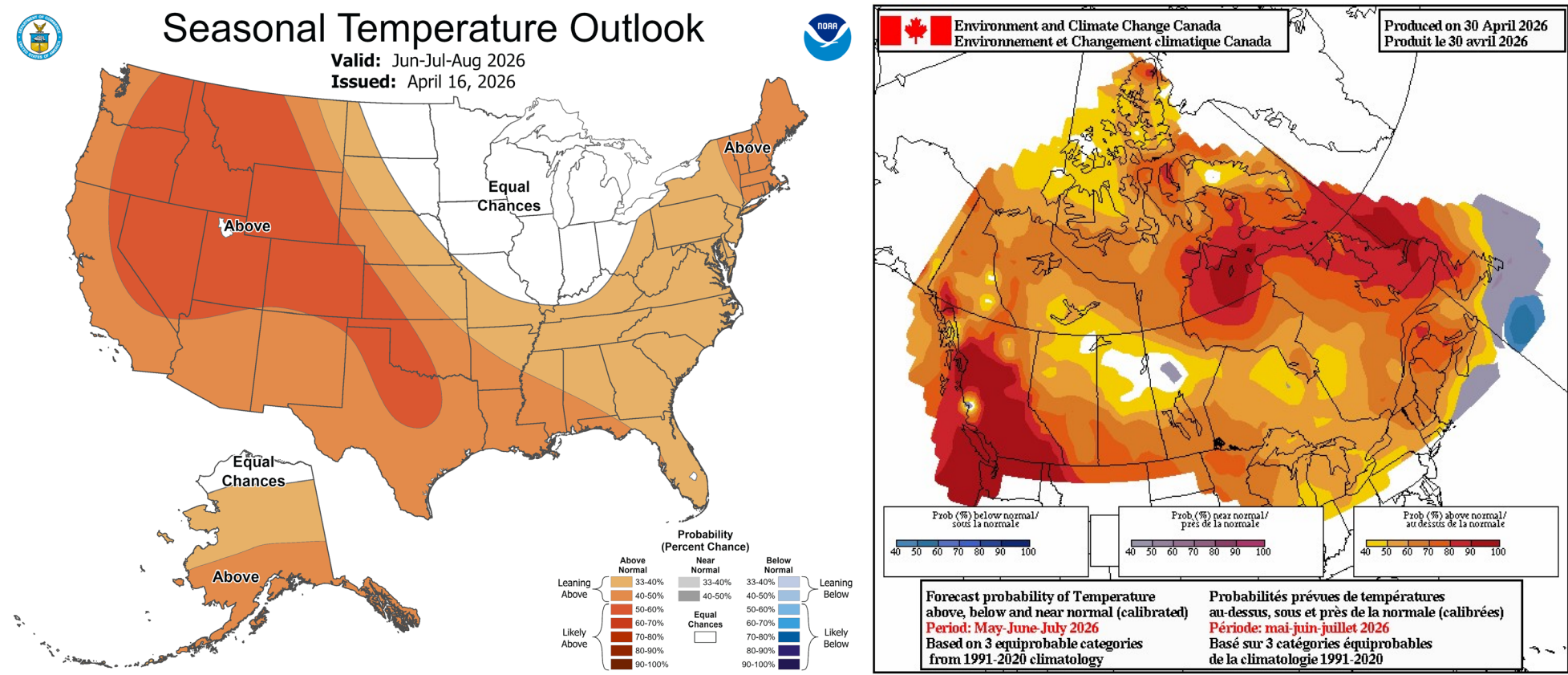


Figure 2: United States and Canada Summer Temperature Outlook¹⁵

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.

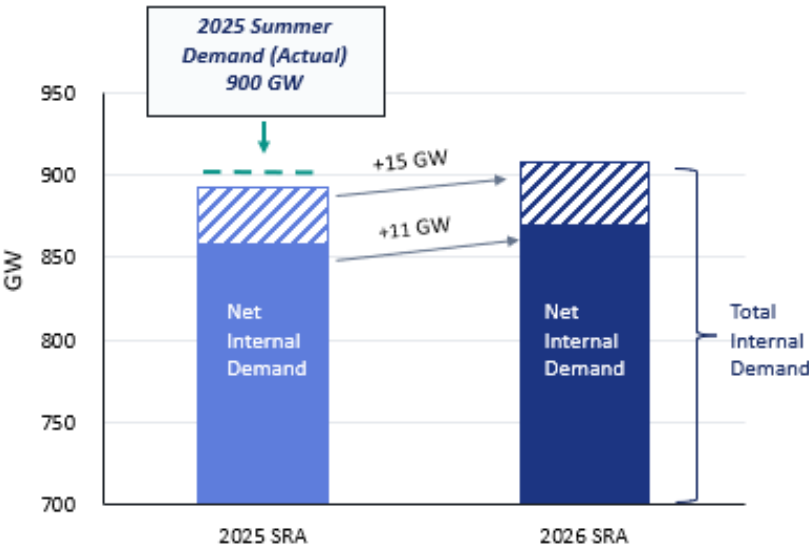


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

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.

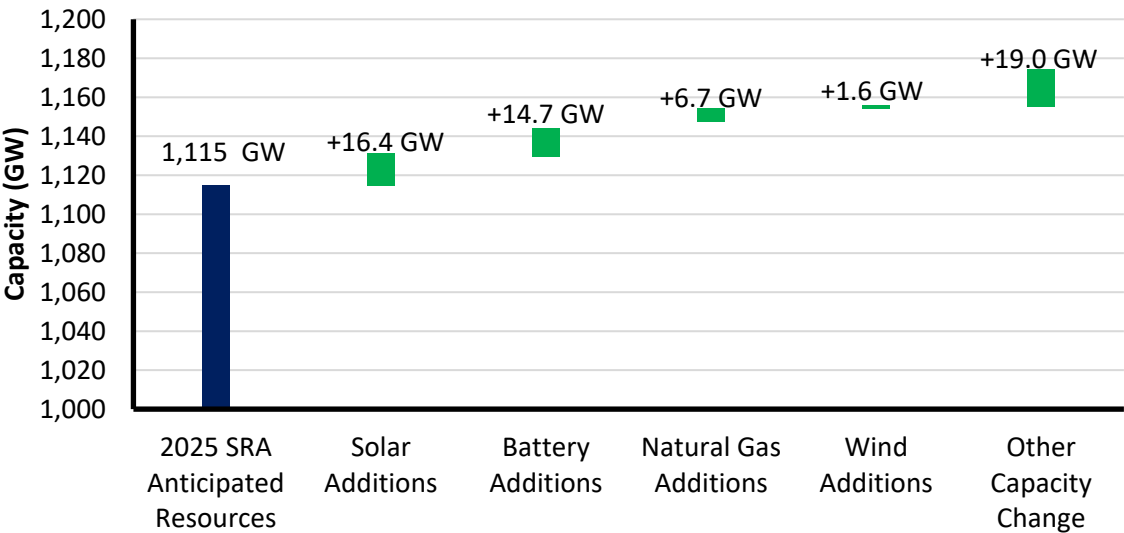


Figure 4: Summer BPS Resource Capacity Change Since 2025

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	- 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 scenarios²
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- 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 scenarios² (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 scenarios³ (i.e., extreme outage and derate scenarios)
Potential for insufficient operating reserves in above-normal conditions	
Normal	- 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 scenarios⁴
Sufficient operating reserves expected	

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 of 1.178 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

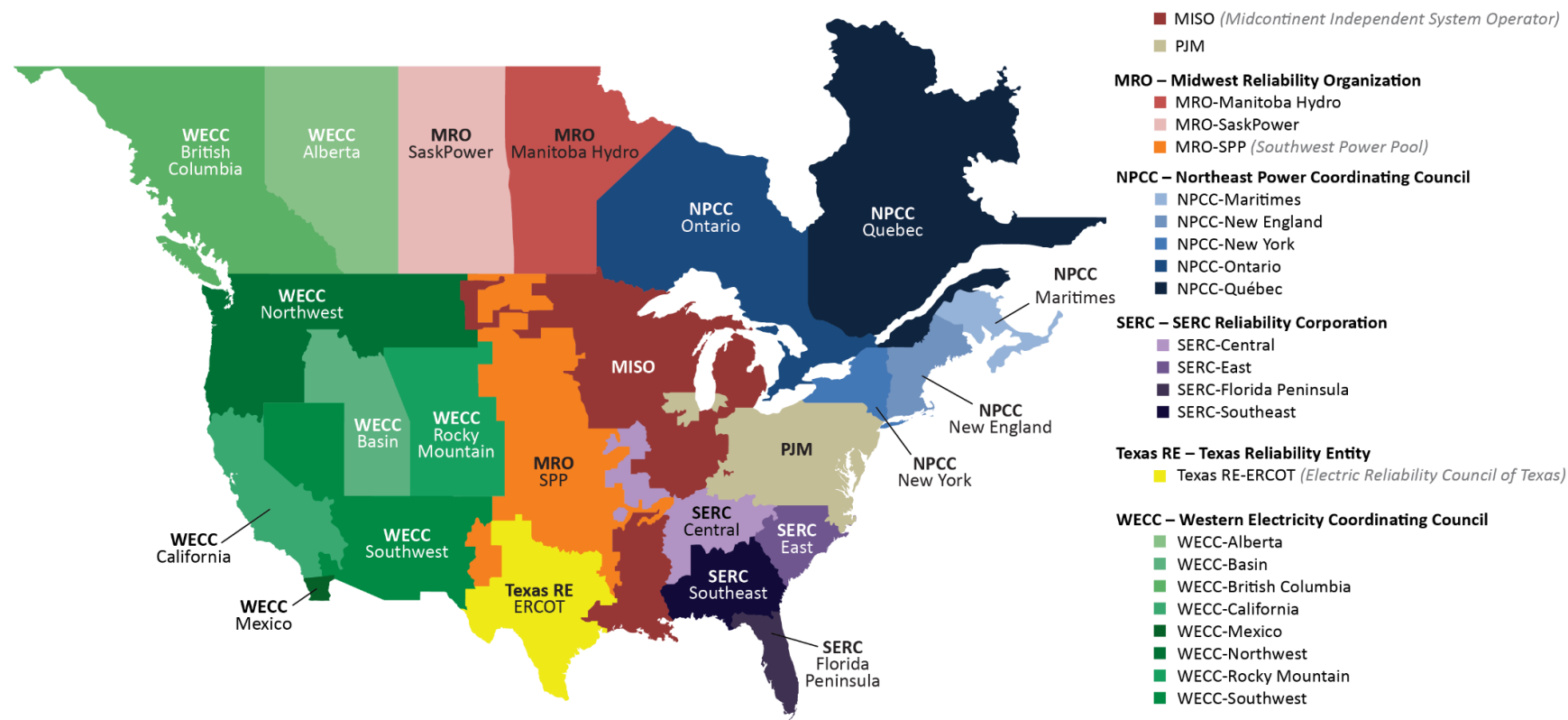
Table 4: Probability-Based Risk Assessment

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 SERVIM 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.

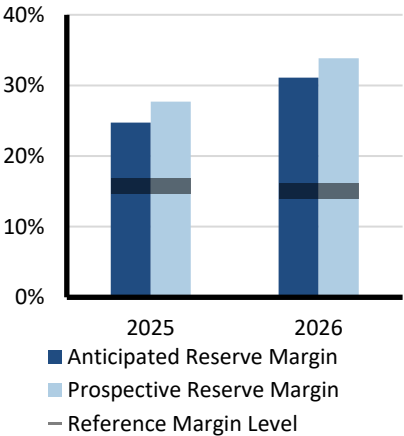
Highlights

- 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.

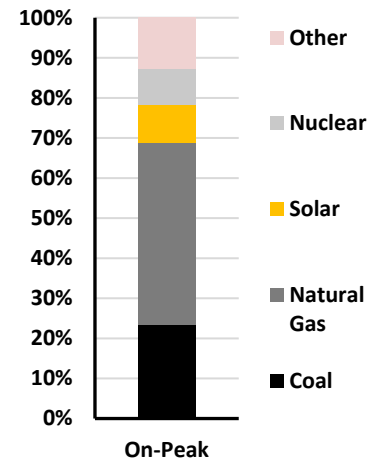
Risk Scenario Summary

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.

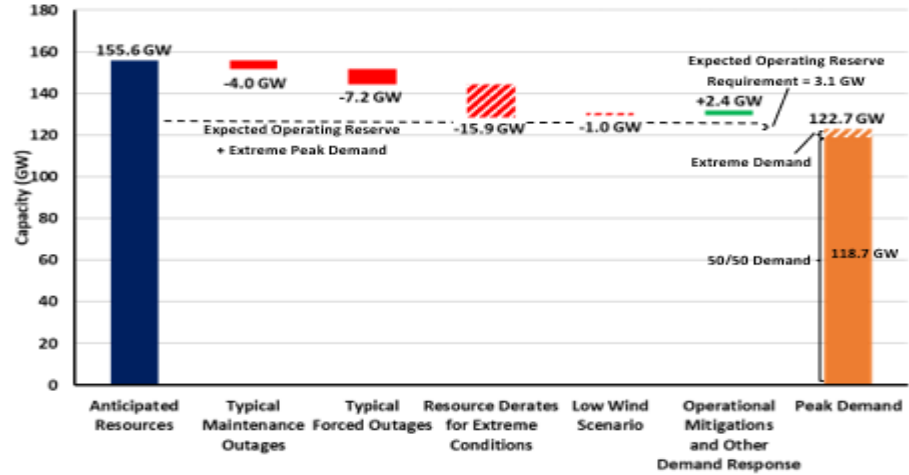
On-Peak Reserve Margin



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.

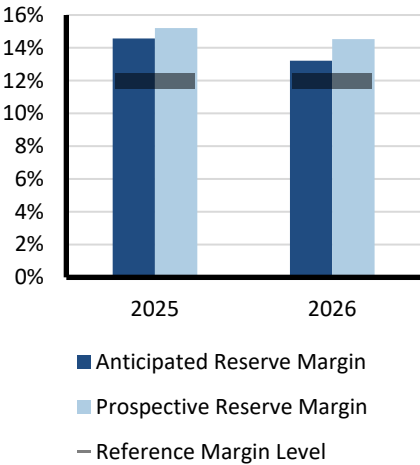
Highlights

- 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.

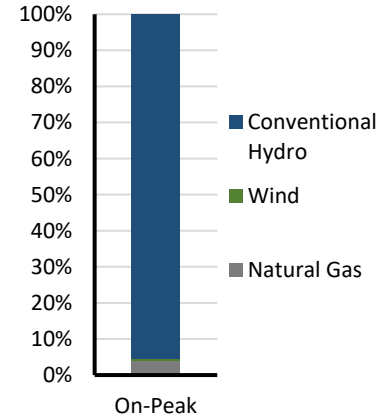
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

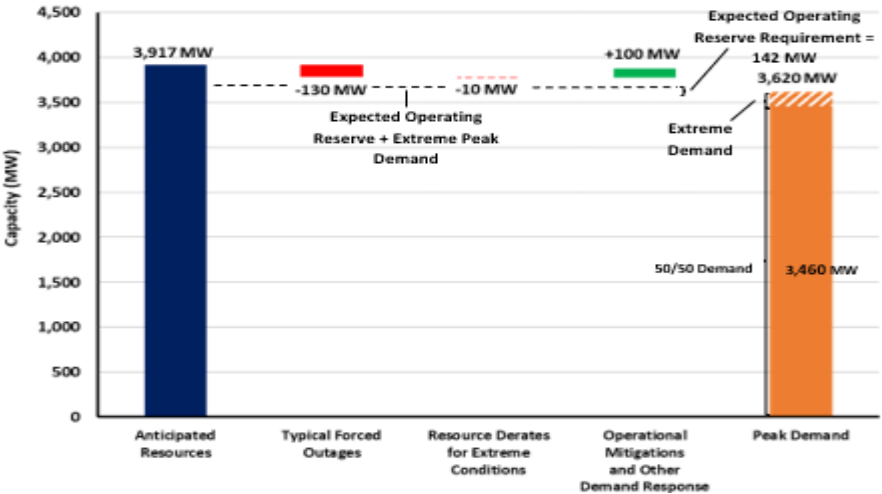
On-Peak Reserve Margin



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.

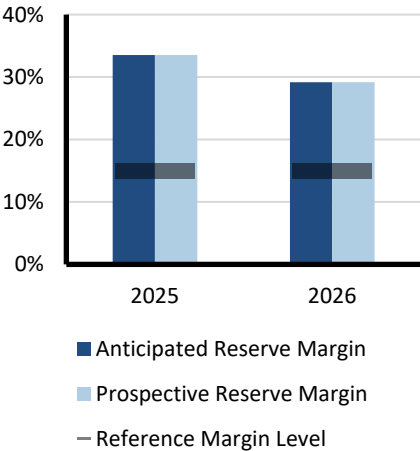
Highlights

- 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.

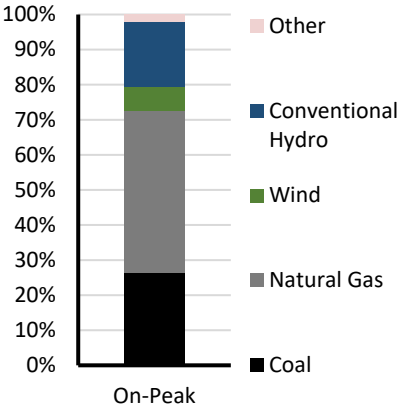
Risk Scenario Summary

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.

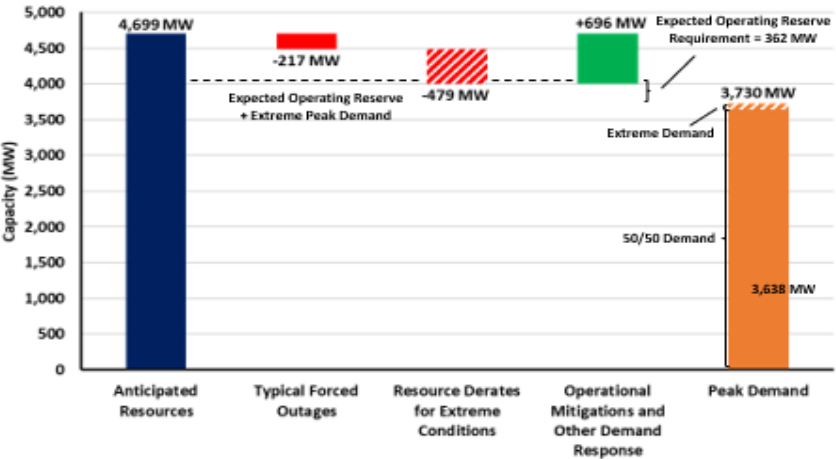
On-Peak Reserve Margin



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-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.

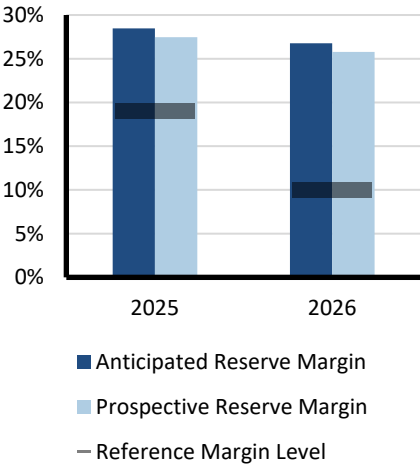
Highlights

- 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.

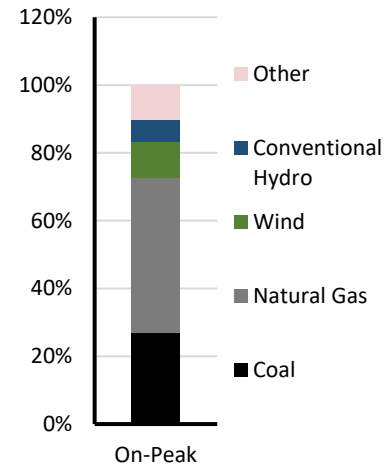
Risk Scenario Summary

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.

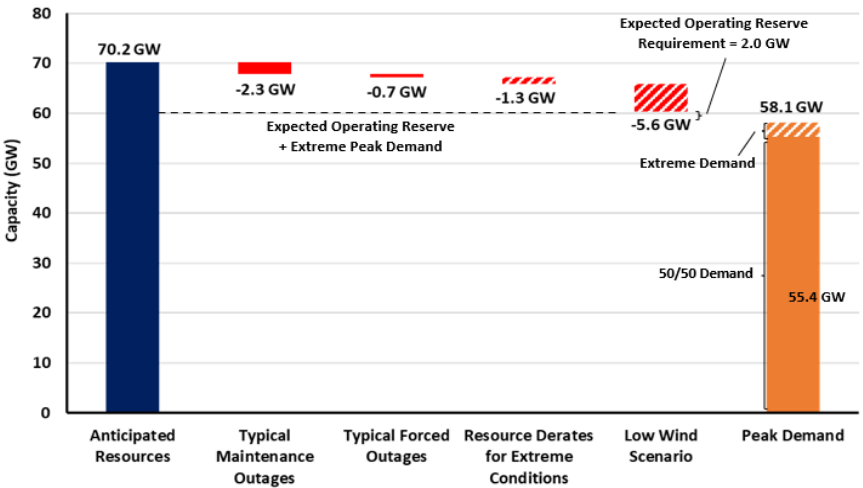
On-Peak Reserve Margin



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.

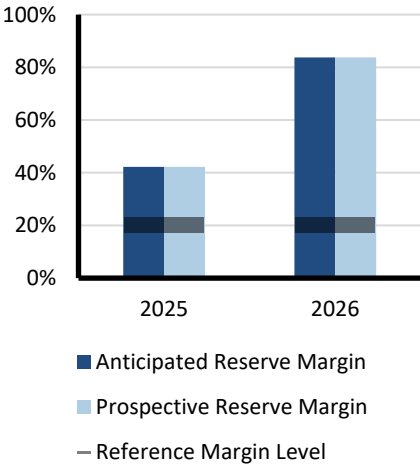
Highlights

- 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.

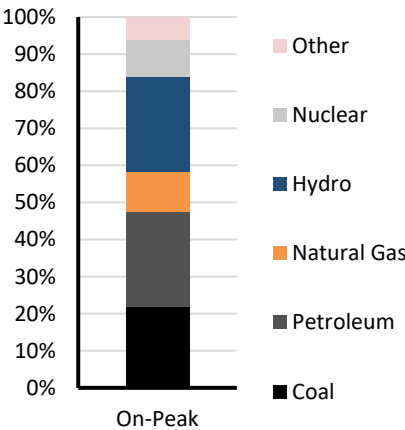
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

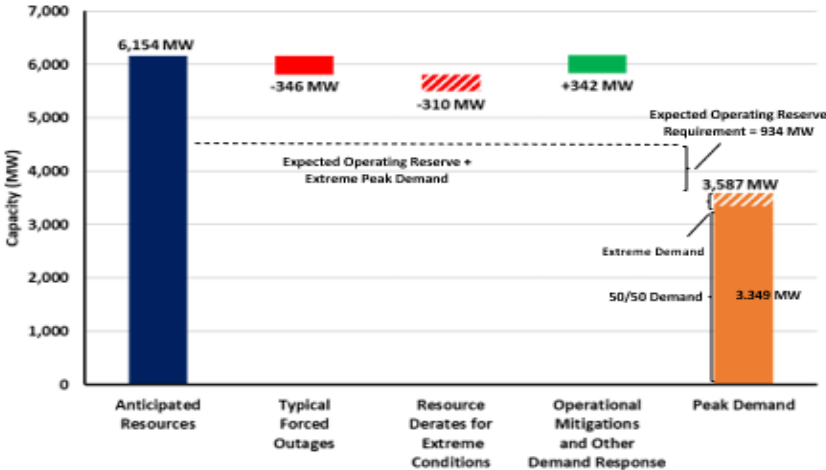
On-Peak Reserve Margin



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.

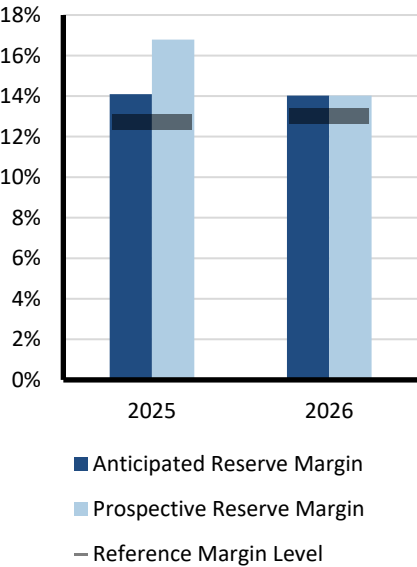
Highlights

- 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.

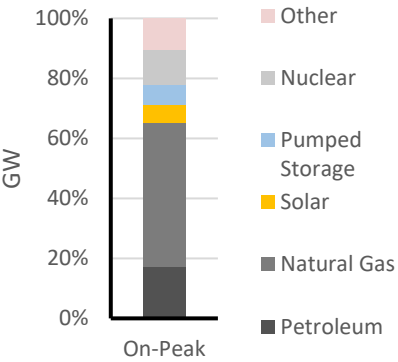
Risk Scenario Summary

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.

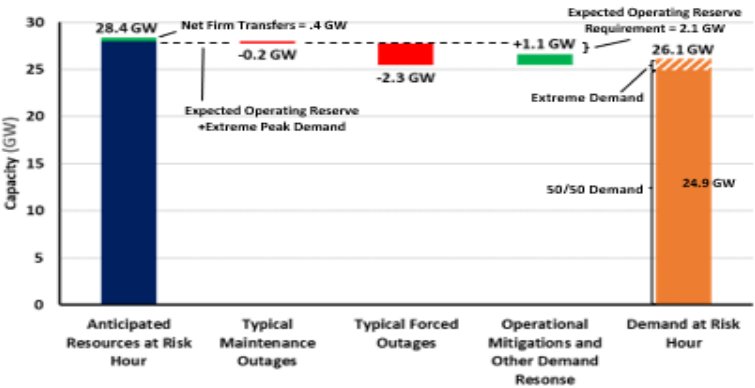
On-Peak Reserve Margin



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:** 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%.

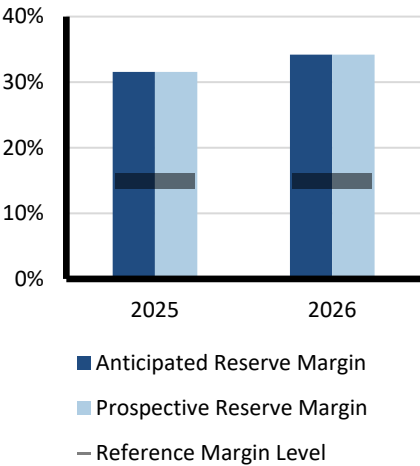
Highlights

- 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

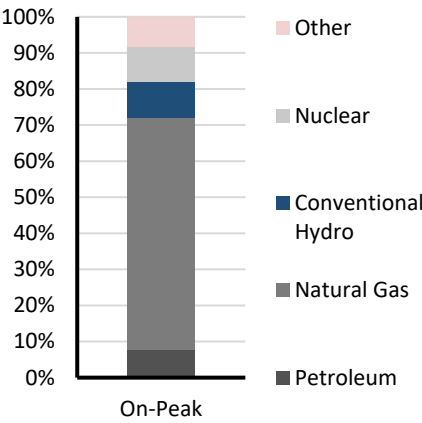
Risk Scenario Summary

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.

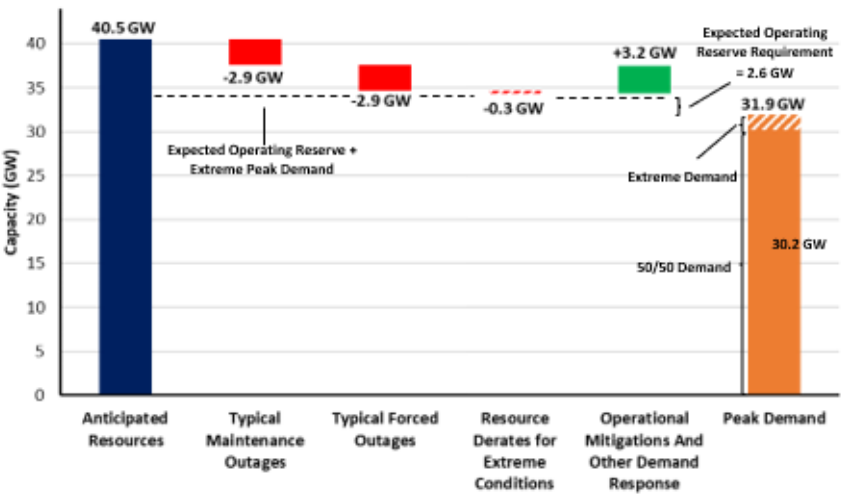
On-Peak Reserve Margin



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.

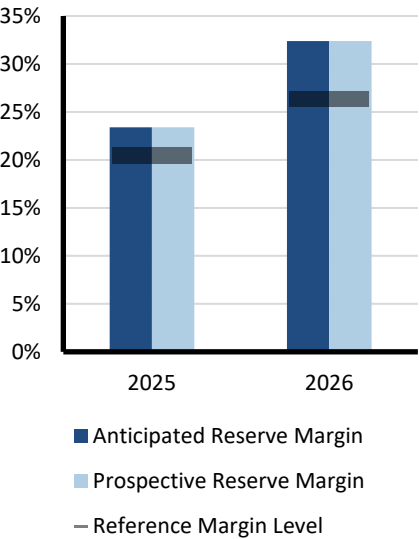
Highlights

- 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.

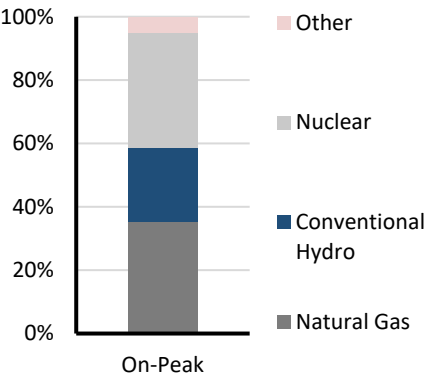
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

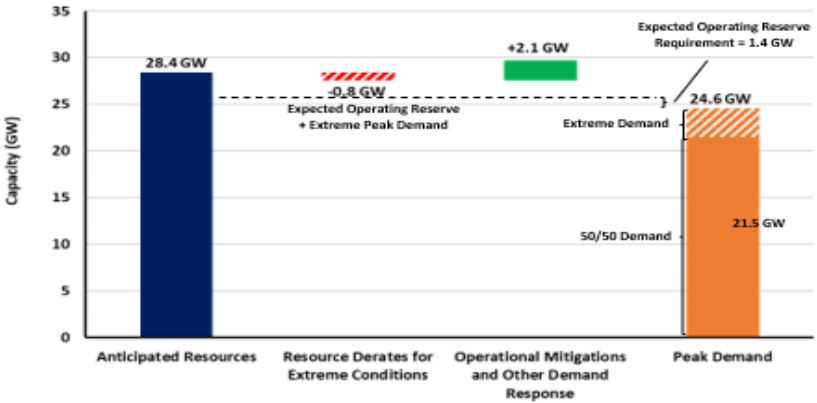
On-Peak Reserve Margin



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.

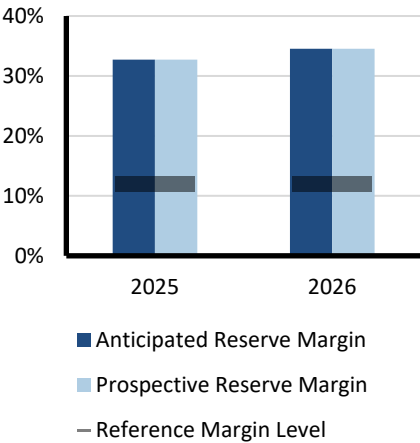
Highlights

- 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.

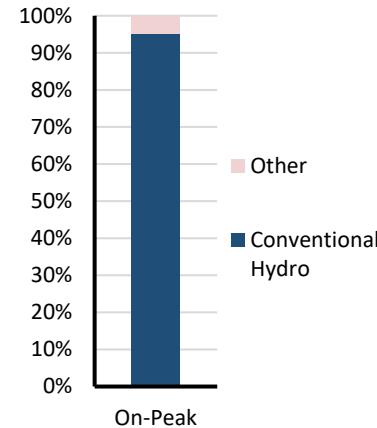
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

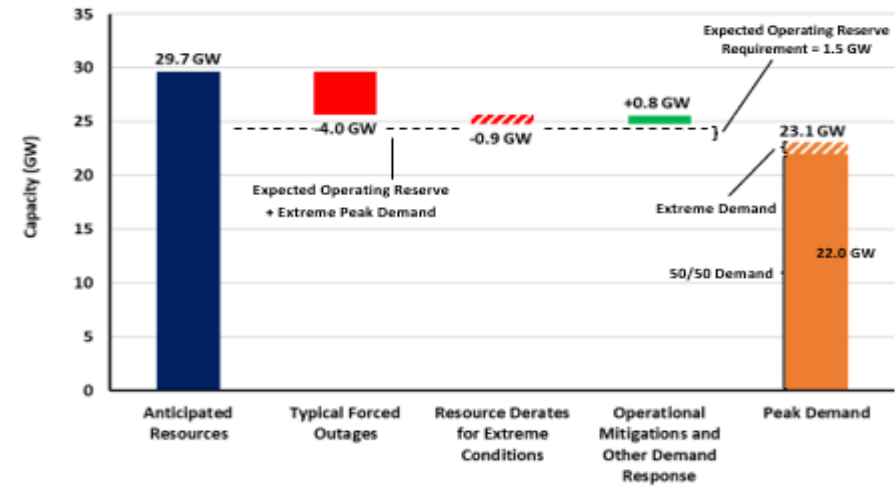
On-Peak Reserve Margin



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.

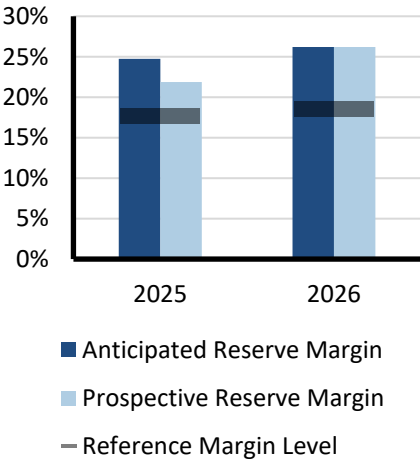
Highlights

- 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.

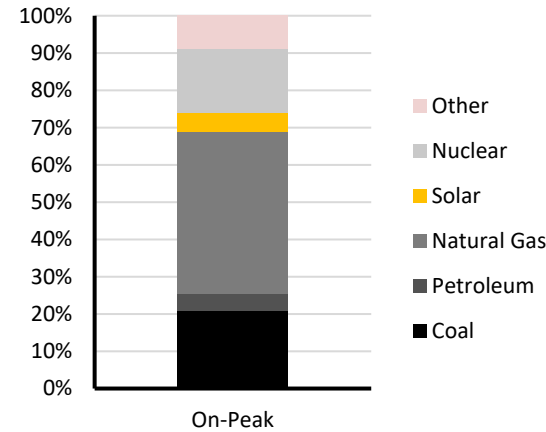
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

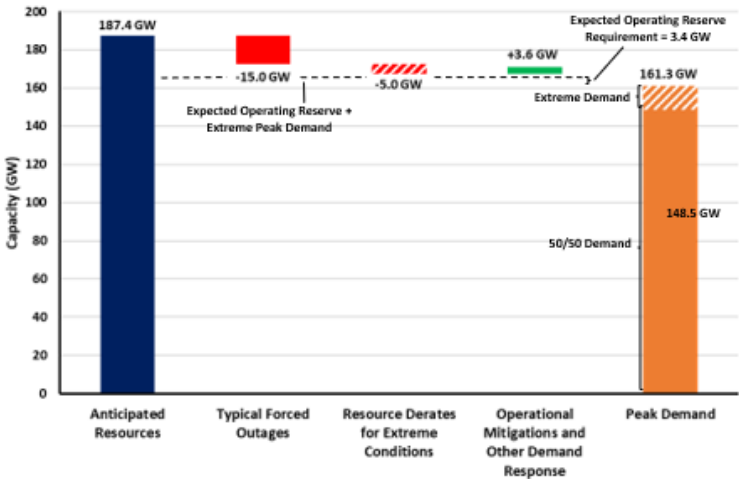
On-Peak Reserve Margin



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 (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.



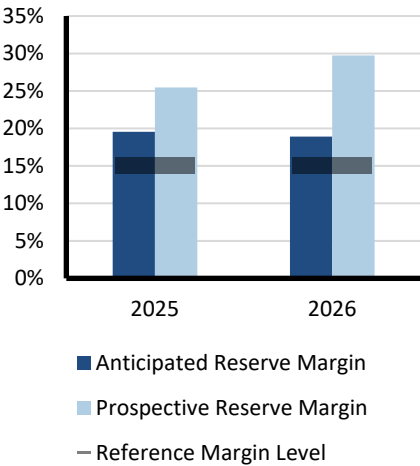
SERC-Central

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.

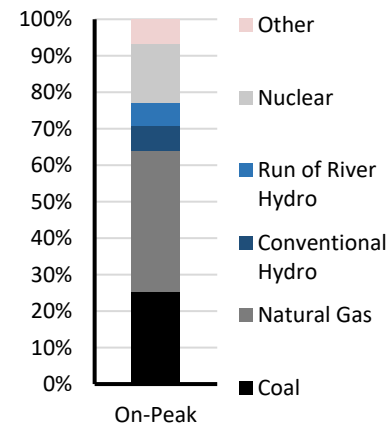
On-Peak Reserve Margin



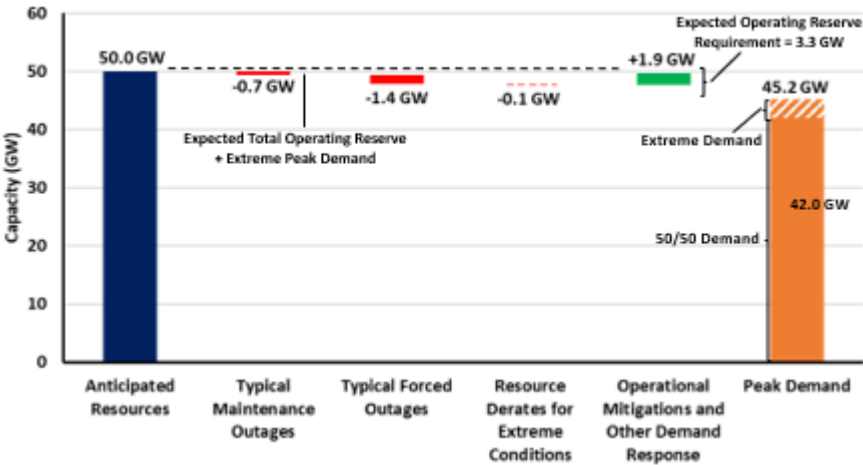
Risk Scenario Summary

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.



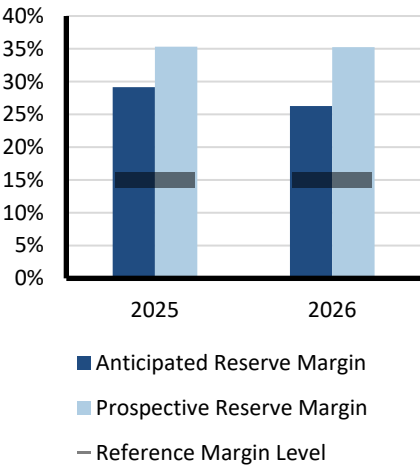
SERC-East

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.

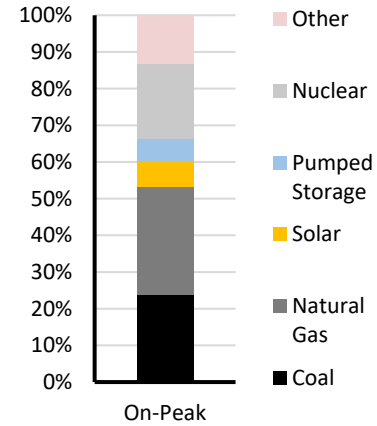
On-Peak Reserve Margin



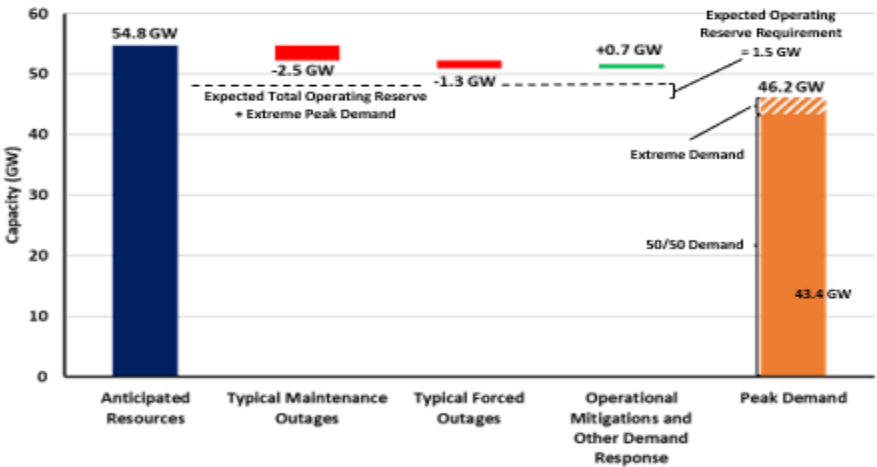
Risk Scenario Summary

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.



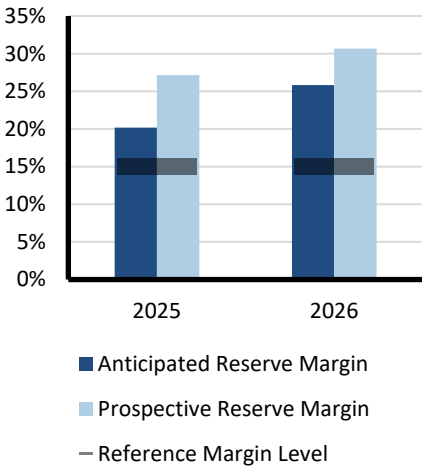
SERC-Florida Peninsula

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.

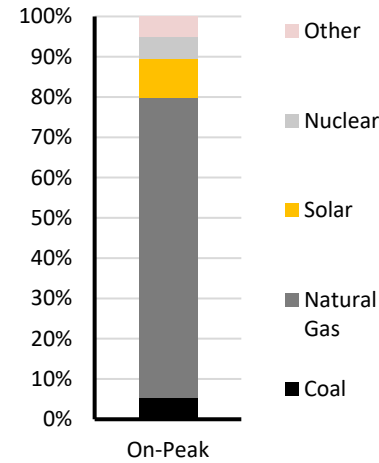
On-Peak Reserve Margin



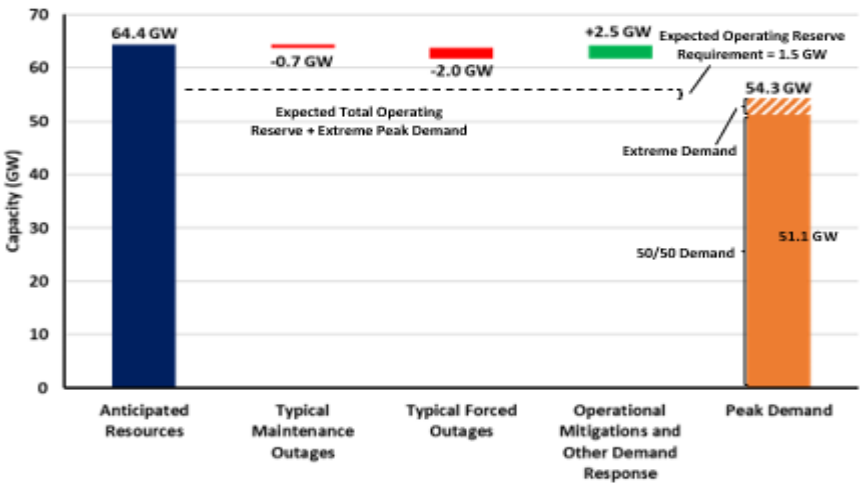
Risk Scenario Summary

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.



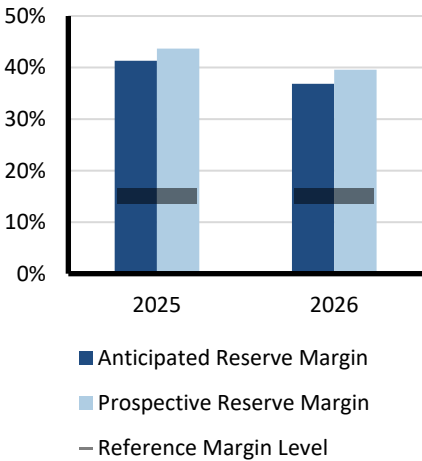
SERC-Southeast

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.

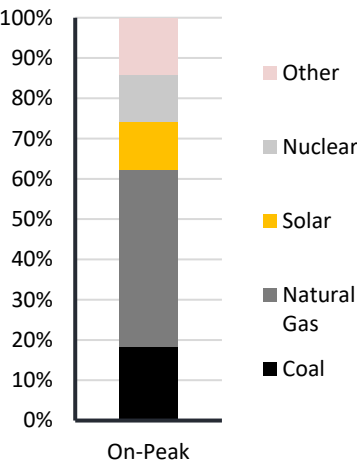
On-Peak Reserve Margin



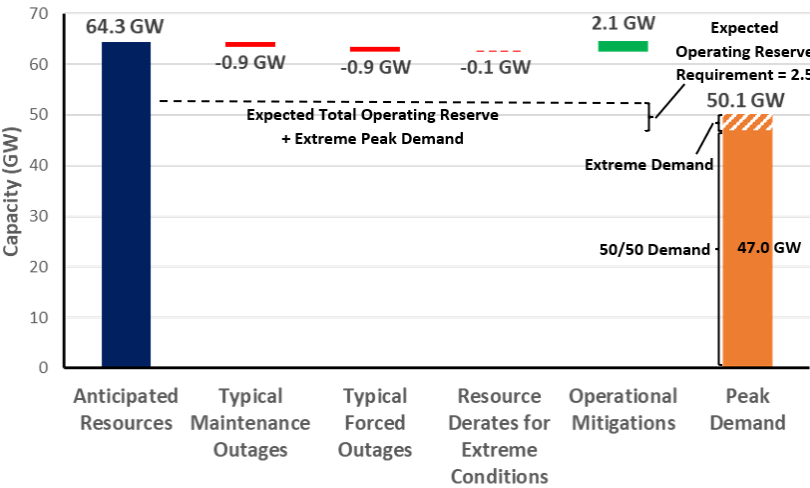
Risk Scenario Summary

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.

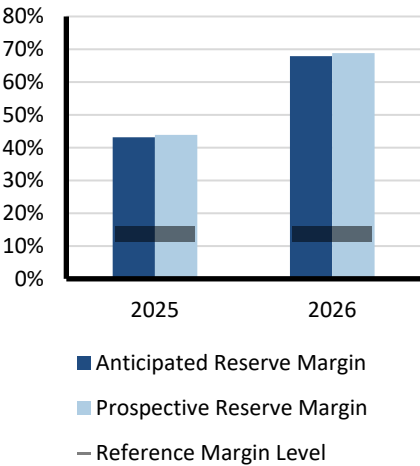
Highlights

- 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.

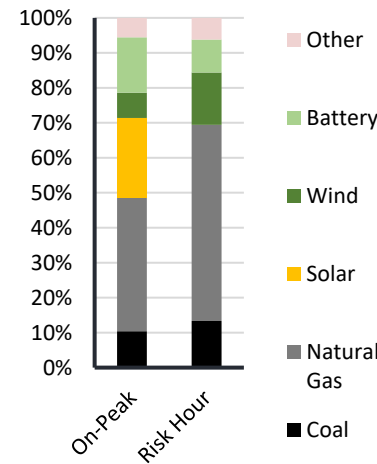
Risk Scenario Summary

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).

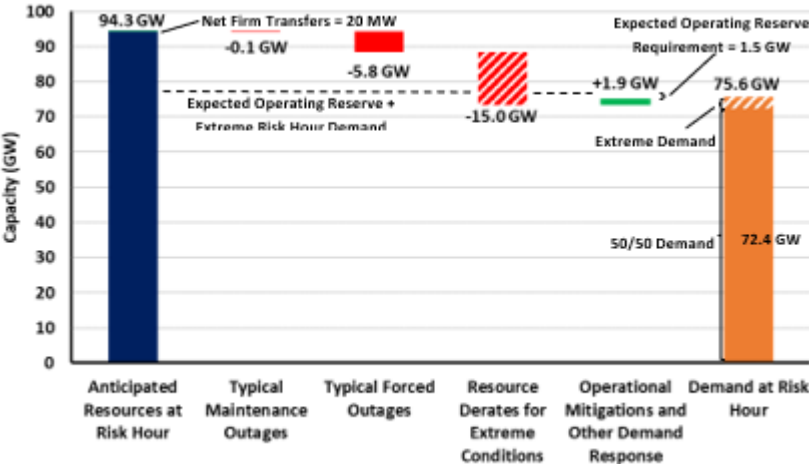
On-Peak Reserve Margin



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.



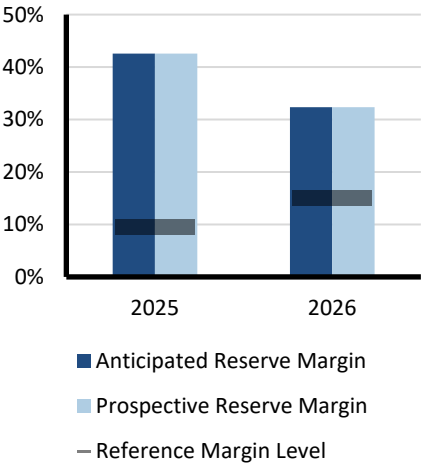
WECC-Alberta

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.

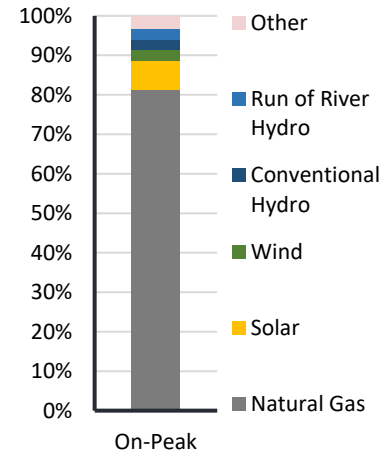
On-Peak Reserve Margin



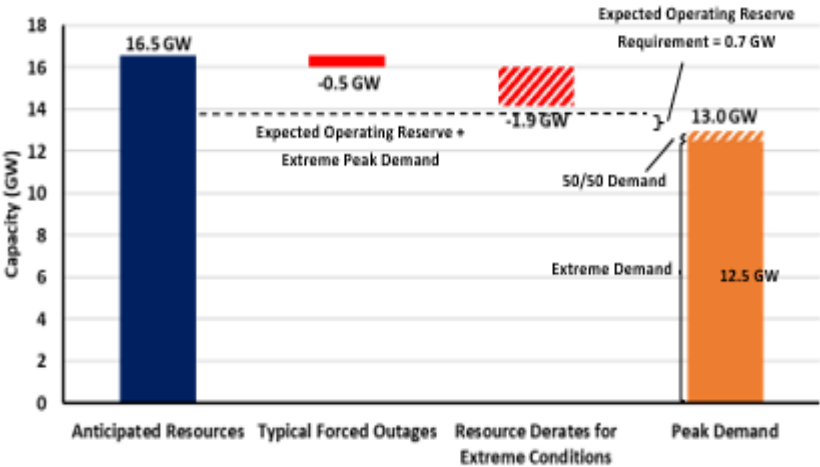
Risk Scenario Summary

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.

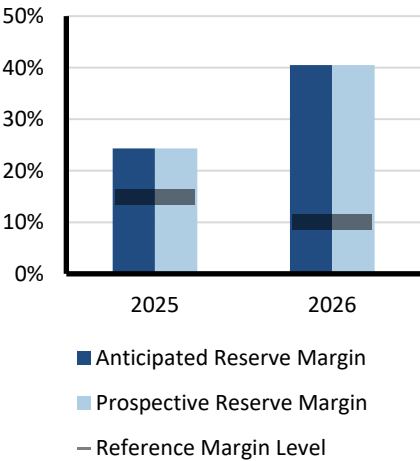
Highlights

- 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%

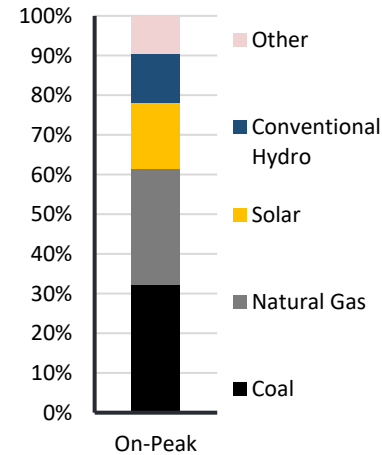
Risk Scenario Summary

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

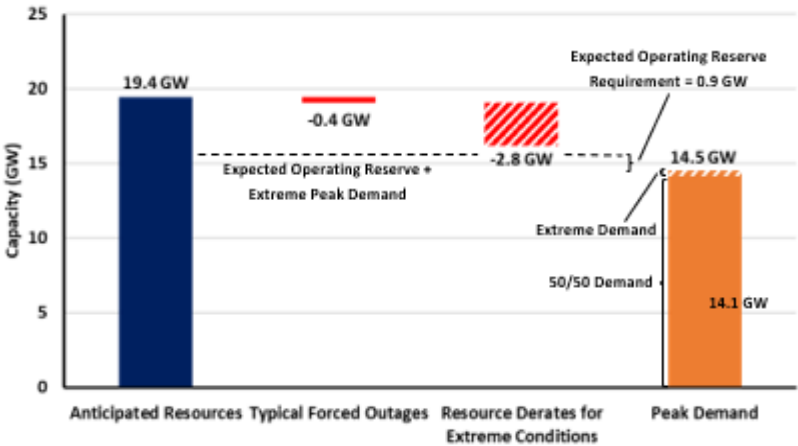
On-Peak Reserve Margin



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 (90/10) demand forecast.
- Forced Outages:** Average seasonal outages.
- Extreme Derates:** (90/10) resource performance distribution at peak hour.



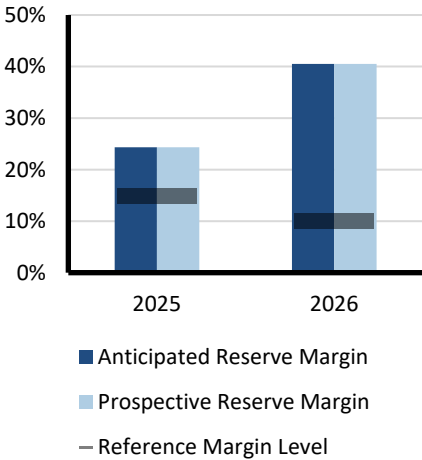
WECC-British Columbia

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.

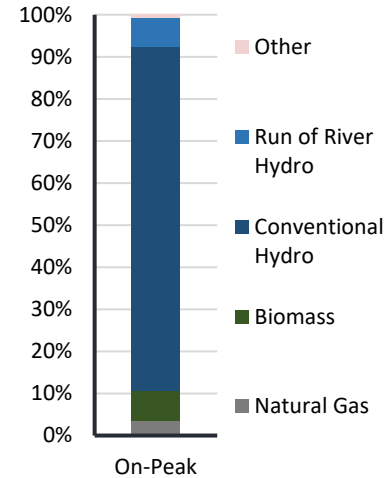
On-Peak Reserve Margin



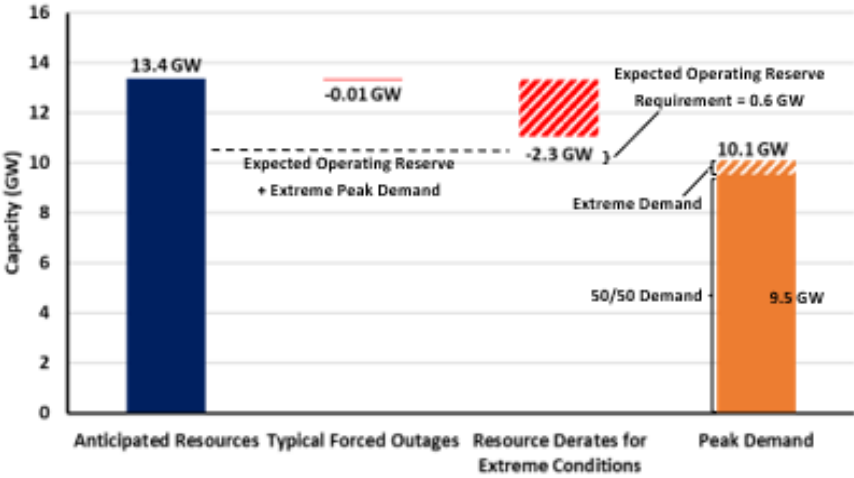
Risk Scenario Summary

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.



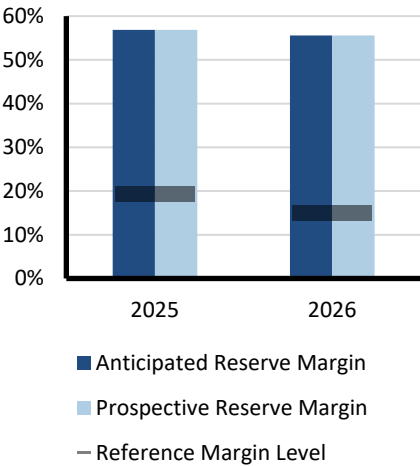
WECC-California

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.

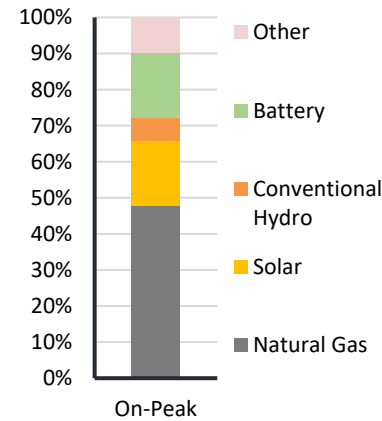
On-Peak Reserve Margin



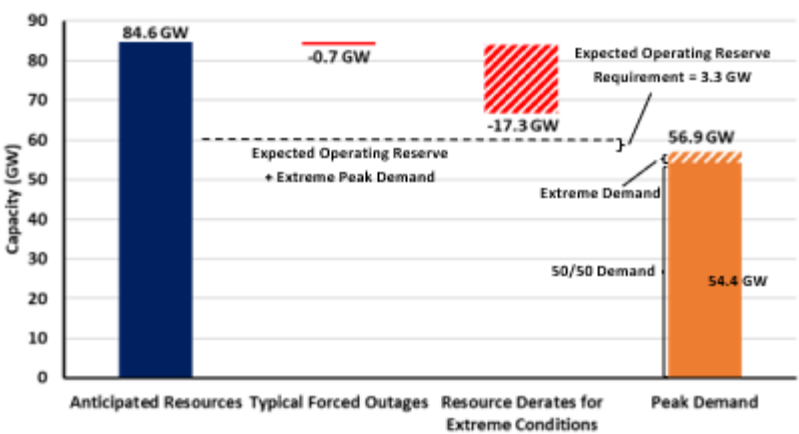
Risk Scenario Summary

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 SERVIM 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.



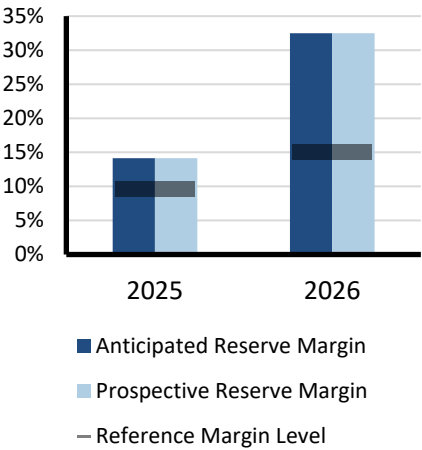
WECC-Mexico

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.

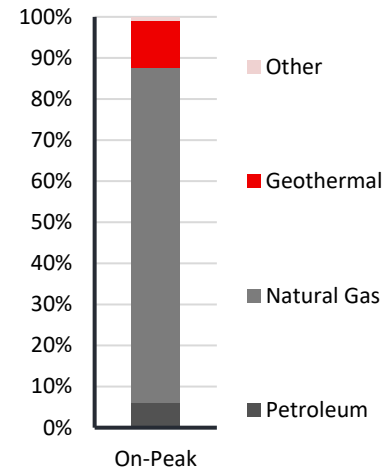
On-Peak Reserve Margin



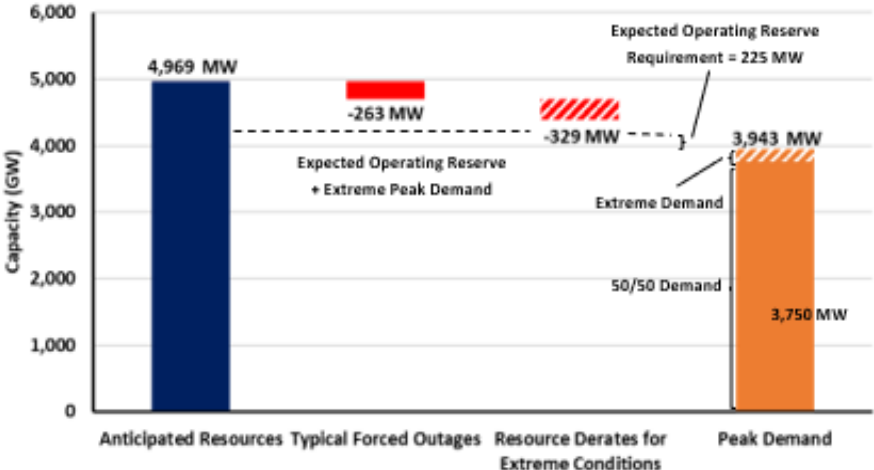
Risk Scenario Summary

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.

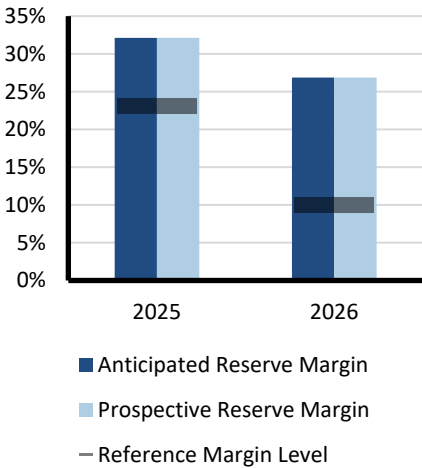
Highlights

- 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.

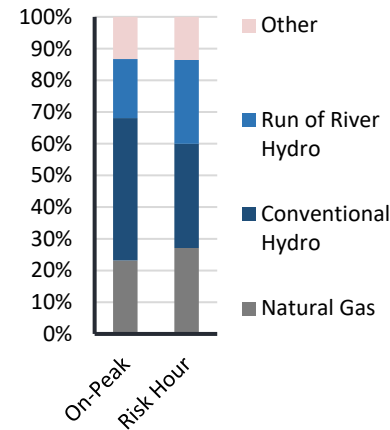
Risk Scenario Summary

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.

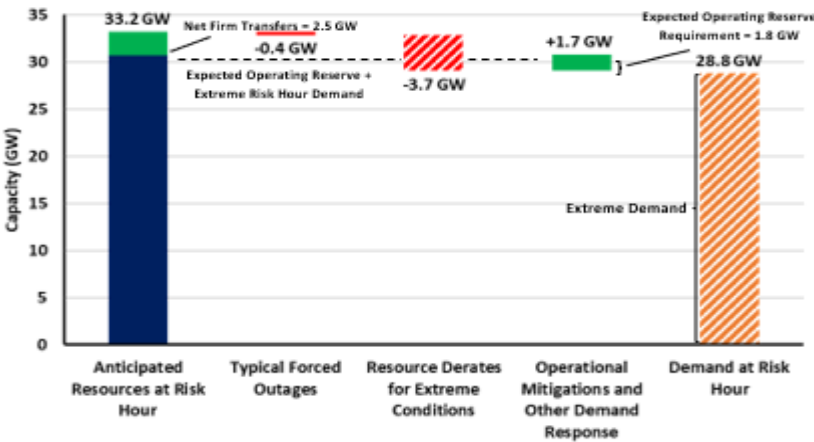
On-Peak Reserve Margin



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.



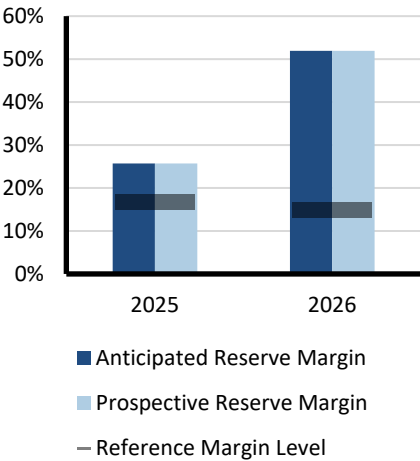
WECC-Rocky Mountain

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.

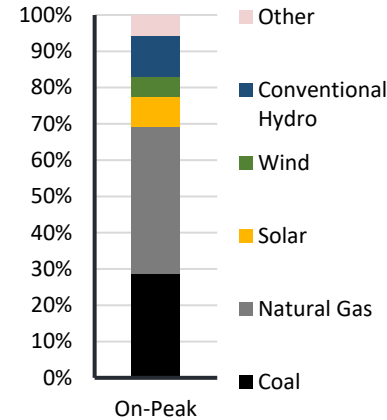
On-Peak Reserve Margin



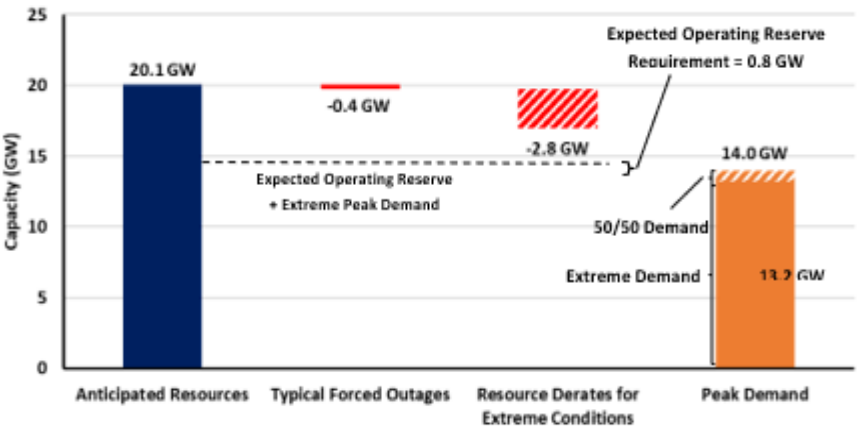
Risk Scenario Summary

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.

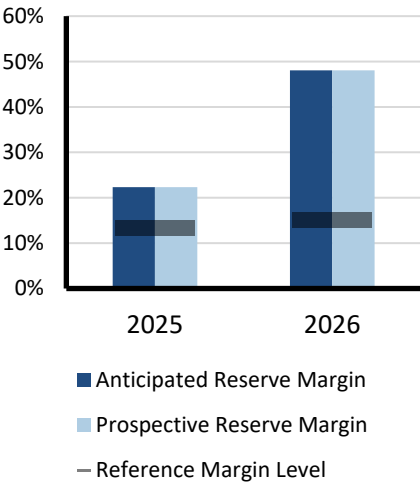
Highlights

- 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.

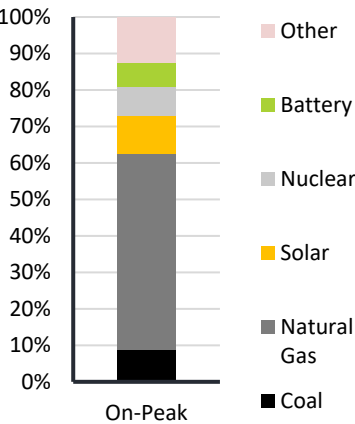
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

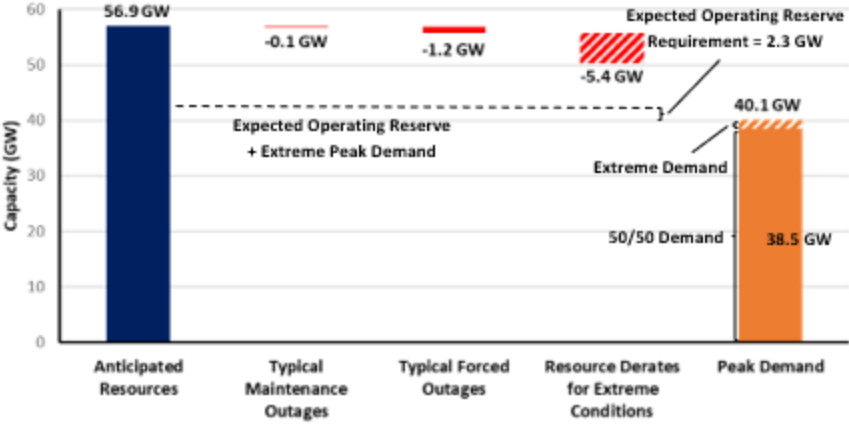
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy 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 load¹⁷ 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 coincident²⁰ 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.
<u>Anticipated Resources:</u> • 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.
<u>Prospective Resources:</u> 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](#).

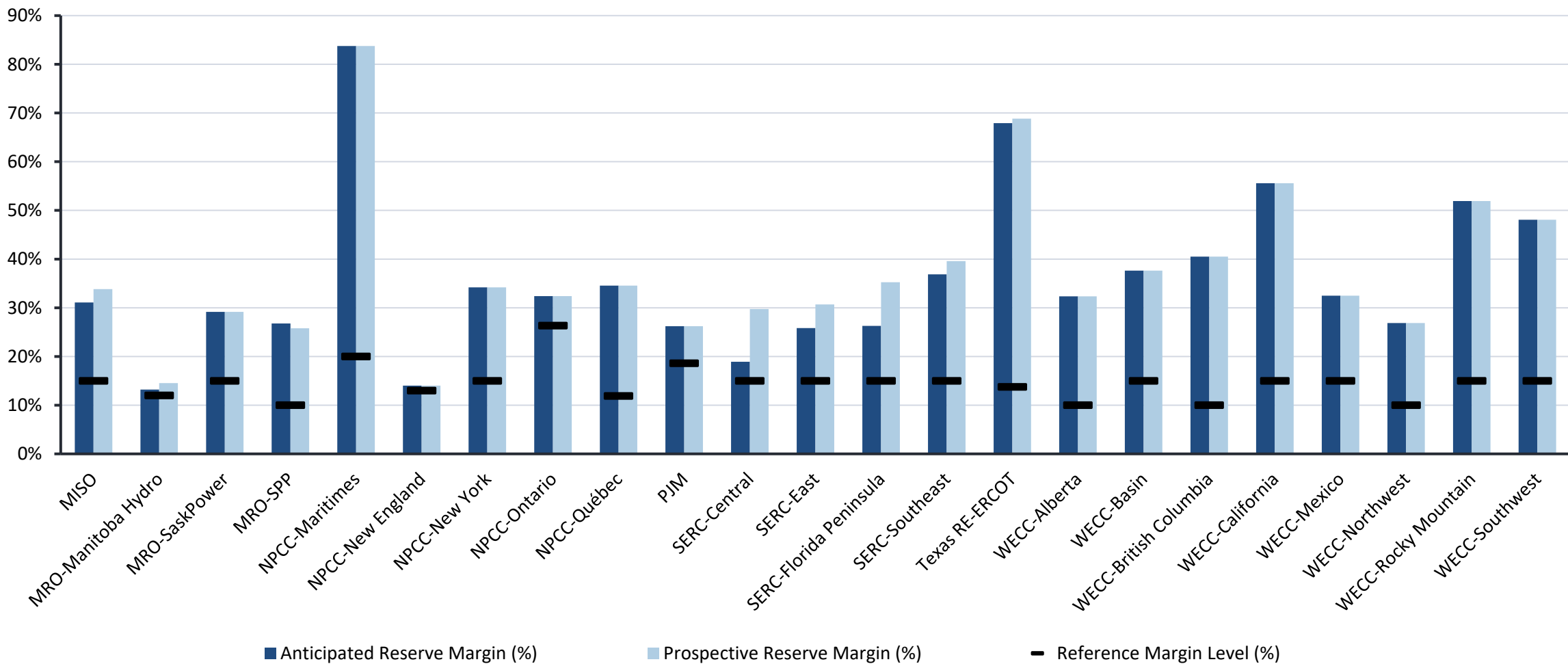


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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.

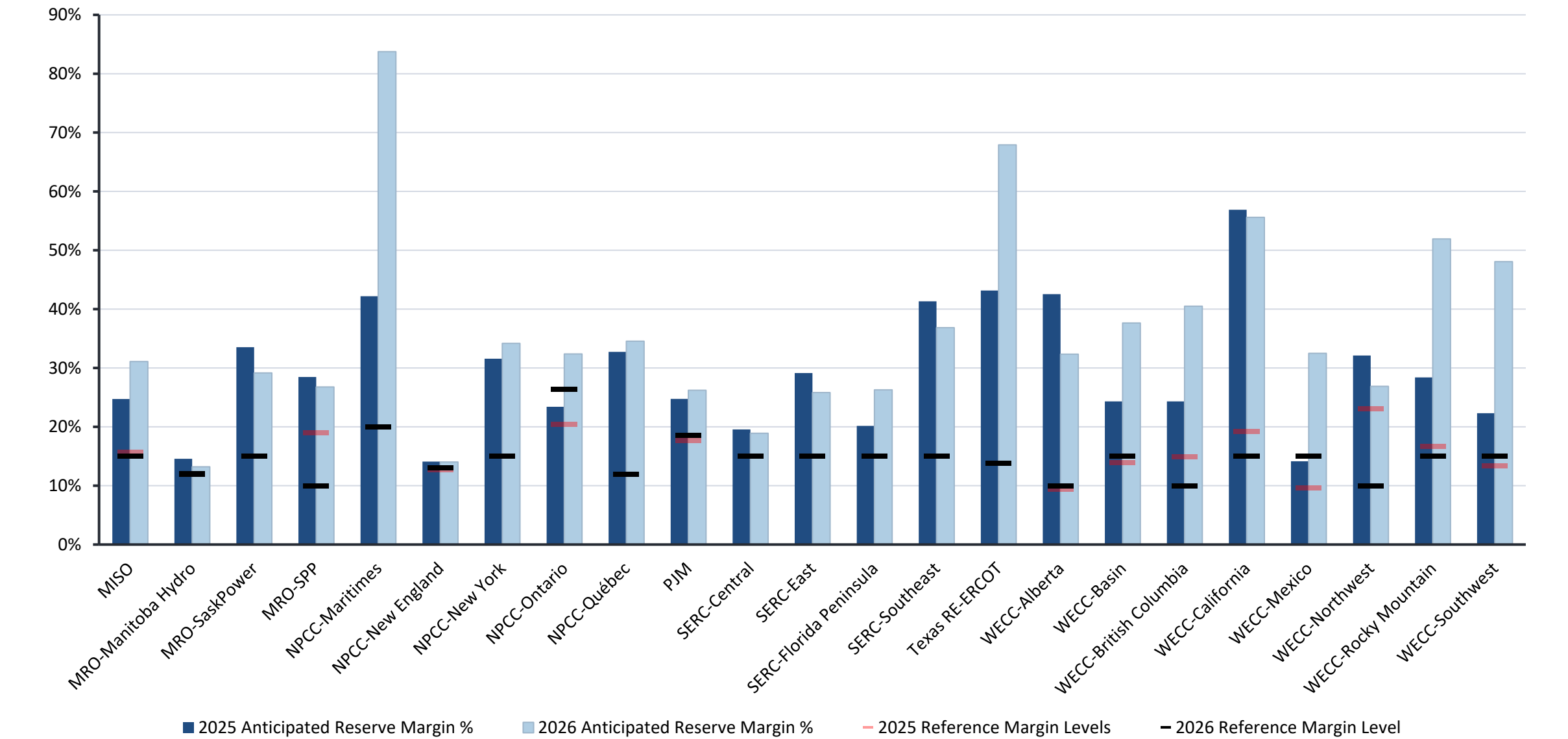


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

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.

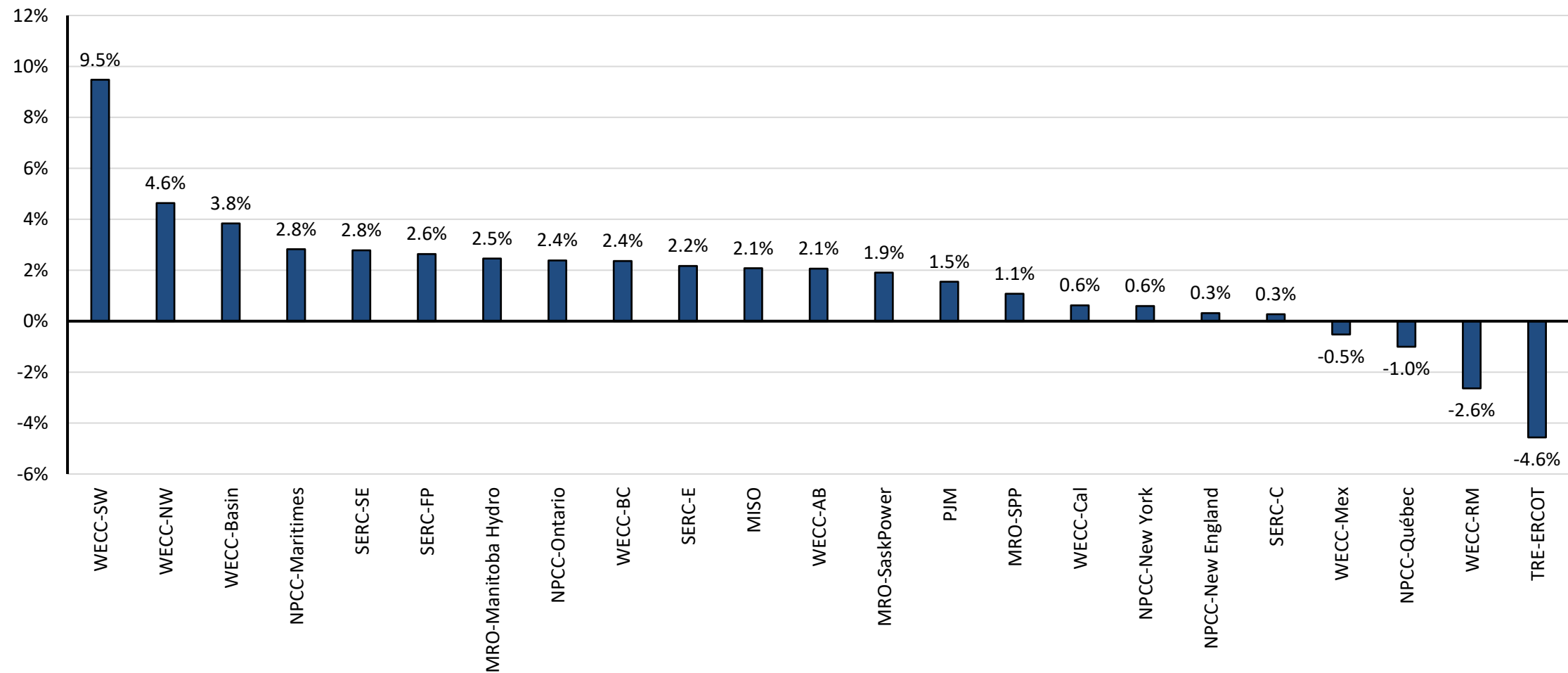


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

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-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-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-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

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

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

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												
Assessment Area / Interconnection	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
	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 States²⁴ 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 States²⁶ and Canada²⁷), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh²⁸, 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 TWh²⁹. 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 heatwave³⁰ 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 record³¹ (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 peak³⁸ 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 1³⁹ 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 unavailable⁴⁰ 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	1,105	6,039	12,323	9,123	8,856
		121.6					
MRO-Manitoba Hydro	3.5	3.4	0	48	0	0	252
		3.6					
MRO-SaskPower	3.6	3.6	232	310	26	9	0
		3.8					
MRO-SPP	54.5	54.8	8,130	5,556	810	492	4,370
		57.5					
NPCC-Maritimes	3.6	3.3	151	314	69	0	33
		3.5					
NPCC-New England	26.6	24.7	566	142	180	1,412	1,963
		26.4					
NPCC-New York	32	30.0	1,256	446	164	243	1,372
		31.7					
NPCC-Ontario	24.9	21.0	607	742	39	66	1,532
		24.5					
NPCC-Québec	23.0	22.3	790	885	0	0	5,029
		23.3					
PJM	160.7	146.2	4,515	1,855	7,730	6,244	15,945
		158.7					
SERC-C	43.2	41.9	84	370	714	1,053	701
		45.7					
SERC-E	44.8	42.5	0	0	3,200	5,022	2,407
		45.7					
SERC-FP	54.6	49.8	0	0	8,035	5,749	1,599
		50.8					
SERC-SE	46.4	45.7	0	0	3,366	7,728	1,380
		55.9					
TRE-ERCOT	83.7	85.2 ⁵	14,509	9,396	16,961	22,962	11,095
		91.3 ⁵					
WECC-AB	12.5	12.2	2,870	796	32	1,480	**
		12.7					
WECC-BC	9.8	9.3	293	149	4.8	0	**
		10.0					
WECC-CA	54	54.1	1,744	1,207	5,064	14,756	1,063
		64.3					

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

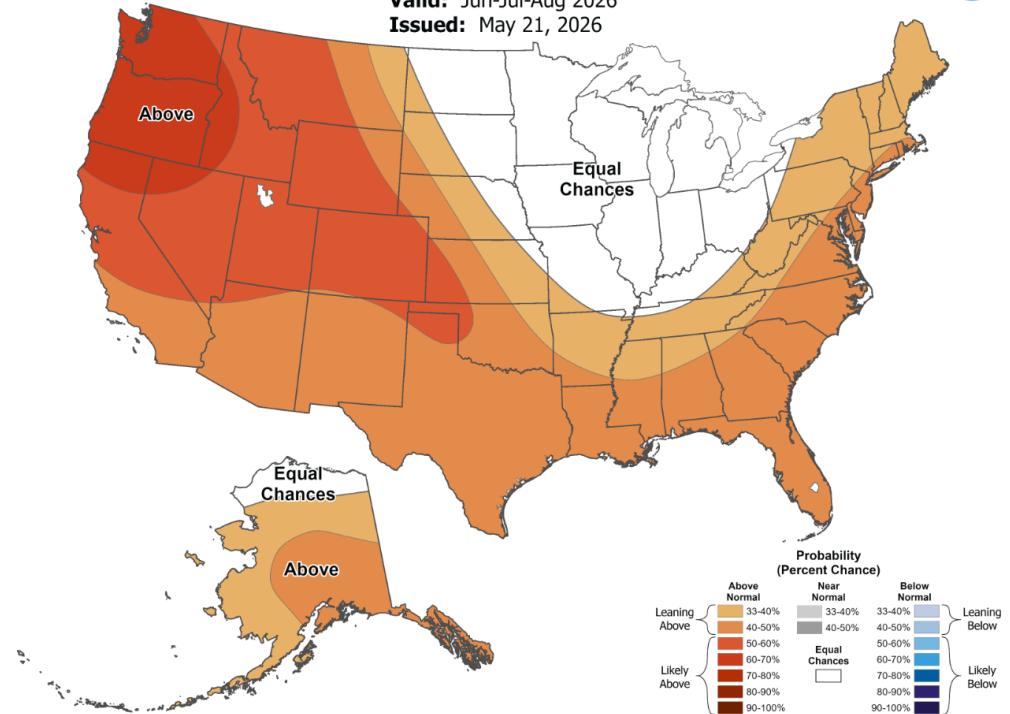
- El Niño conditions increase the chances of above normal summer temperatures in the West
 - West-wide heat leading to coincident peak demand can strain the system
- Western snowpack is below normal, but this is partly offset by above average snowpack and reservoir levels in the Upper Columbia basin 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



Seasonal Temperature Outlook

Valid: Jun-Jul-Aug 2026

Issued: May 21, 2026



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

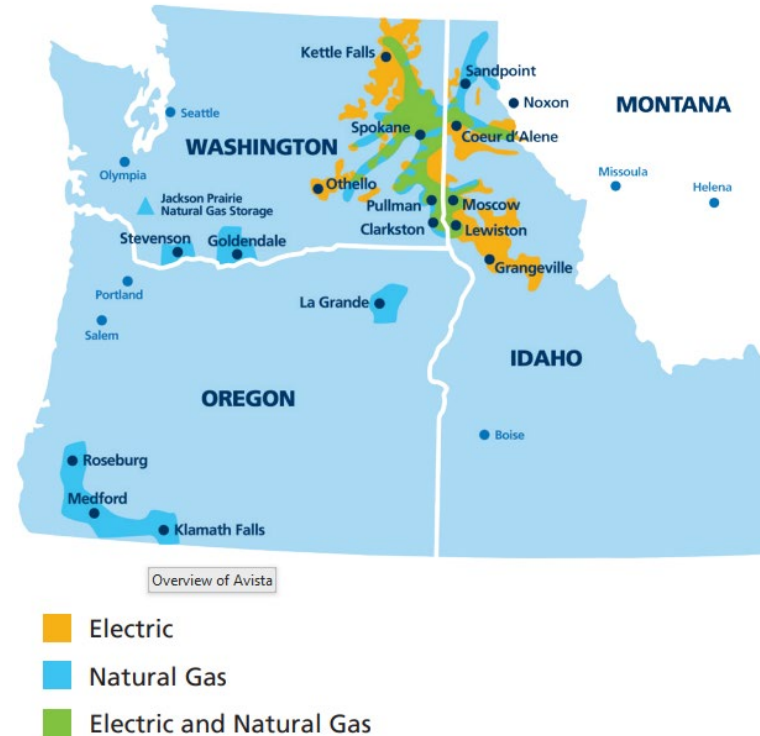
- Enhanced demand response modeling, improving dispatch to reduce PSE's peak demand
- Use of conservative short-term wind assumptions to reduce reliability risk
- Hold additional dispatchable resource capacity to account for risk to higher load and generator under performance

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

EXHIBIT 131-3

Resource Adequacy Requirements: Reliability and Economic Implications

September 2013

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Prepared for



FERC
FEDERAL ENERGY REGULATORY COMMISSION

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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)

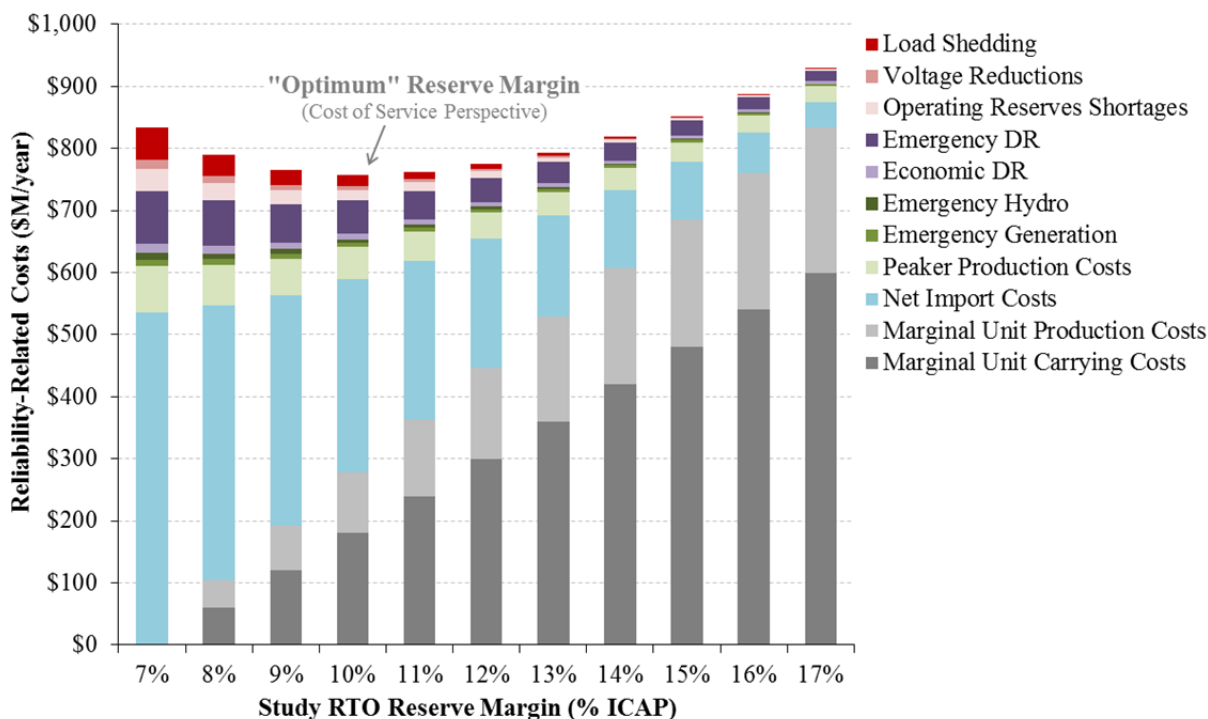


Table ES-1 summarizes the reliability-based and economically-based reserve margin targets for the Base Case simulation and for each of the alternative simulation cases we examined. These results show that varying assumptions regarding system size, topology, price cap, and other factors can substantially 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, inertia 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 Section 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.

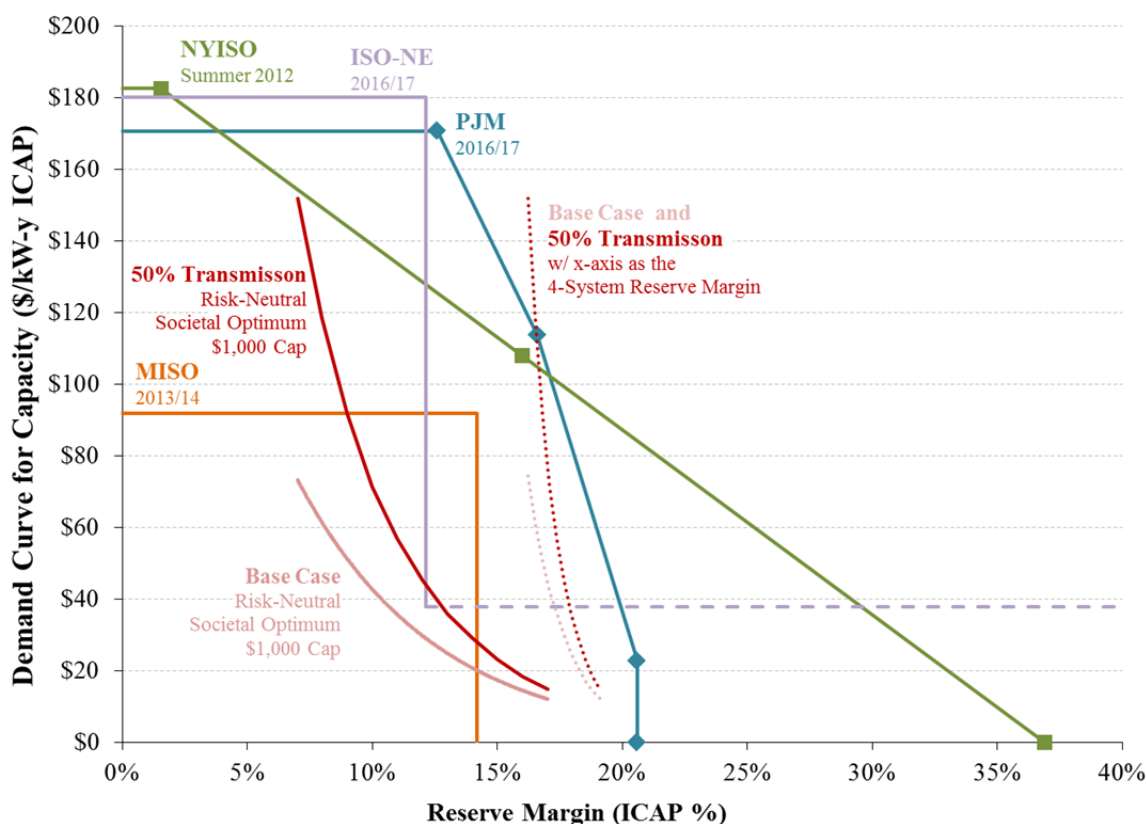
Our simulations demonstrate that a capacity market could be designed to achieve economically-optimal reserve margins through either: (a) imposing economically-based rather than physical reliability-based planning reserve margin requirements; or (b) implementing a demand curve for capacity that is designed 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

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 ReliabilityFirst 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.

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-in-10 standard will be achieved. This is because such supply-related

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.

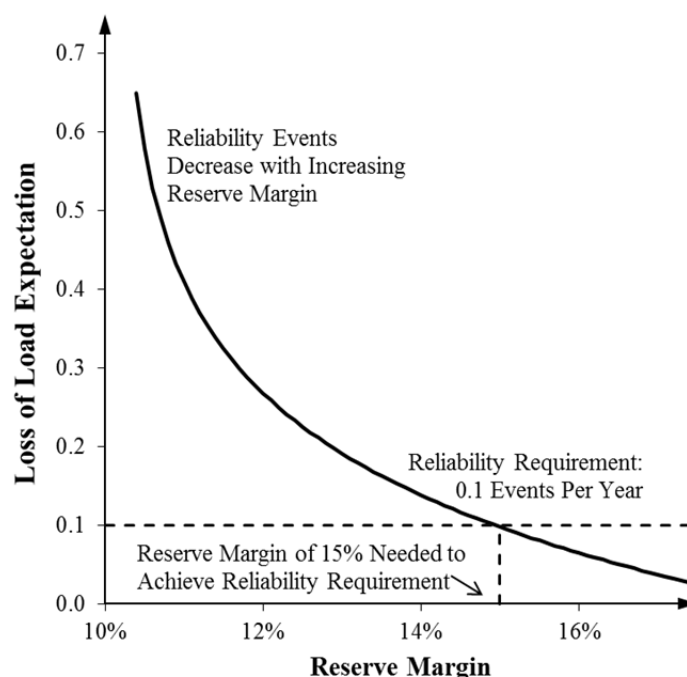
To understand the economic value of different resource adequacy levels, one must also estimate the value of reliability to customers. One component of this reliability value is the ability to avoid costly load shedding events, the value of which can be estimated by: (1) determining the approximate value 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

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).

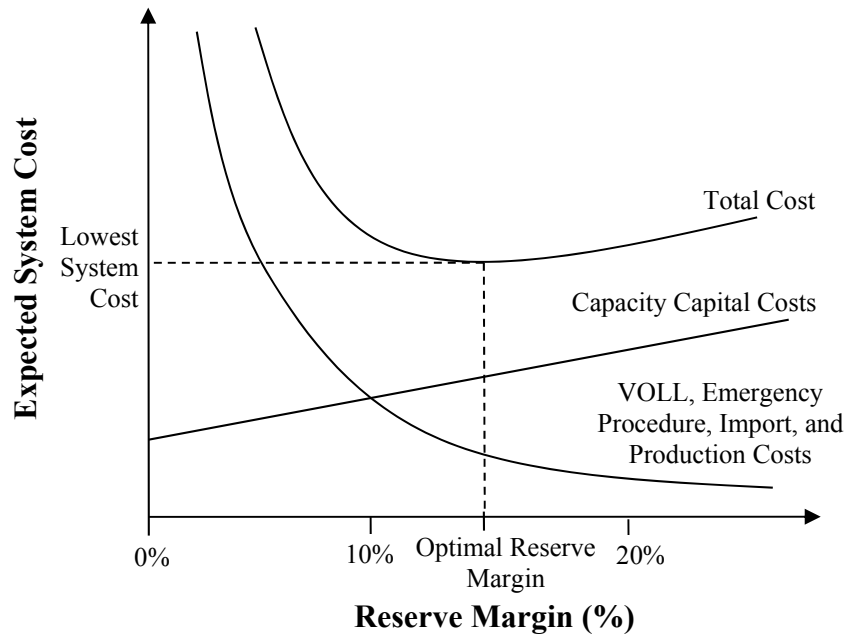
presented in this report. The objective of such an economic reliability study is to determine an “optimal” reserve margin that minimizes total system or customer costs, including the capital cost of adding resources, production costs, off-system and emergency purchase costs, and the cost of load shed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

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 Summer 2012 (MW)	Nameplate Capacity			Derated Value			ICAP Reserve Margin		
		Wind	Solar	DR	Wind	Solar	DR	As Reported	Using Nameplate Capacity	Using Derated Capacity
		(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

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

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, SERVIM, 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

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

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.

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 SERVVM model developed by *Astrape Consulting*.⁴⁰ In this section, we provide an overview of our simulation approach, including a description of the SERVVM 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 (SERVVM) to study the reliability and economic implications of the 1-in-10 standard and alternative resource adequacy standards. Like other reliability modeling tools, SERVVM probabilistically evaluates resource adequacy conditions by simulating generation availability, load profiles, load uncertainty, transmission availability, and other factors. Based on these reliability simulations, SERVVM estimates standard reliability metrics including LOLE, LOLH, and EUE. Unlike other reliability modeling packages, however, SERVVM also simulates economic outcomes including hourly generation dispatch, import-export dynamics, ancillary services, emergency procedures, and investment costs. SERVVM 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 SERVVM 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, SERVVM is managed by *Astrape Consulting*, who provides consulting services and licenses of SERVVM 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 SERVVM 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, SERVVM simulates scarcity prices that exceed generators' marginal production costs as explained further below.

To examine a full range of potential economic and reliability outcomes, SERVVM 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

⁴¹ Note that SERVVM 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 SERVVM 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, SERVVM 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 is the economic and operational characterization of emergency procedures. For this reason, SERVVM 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

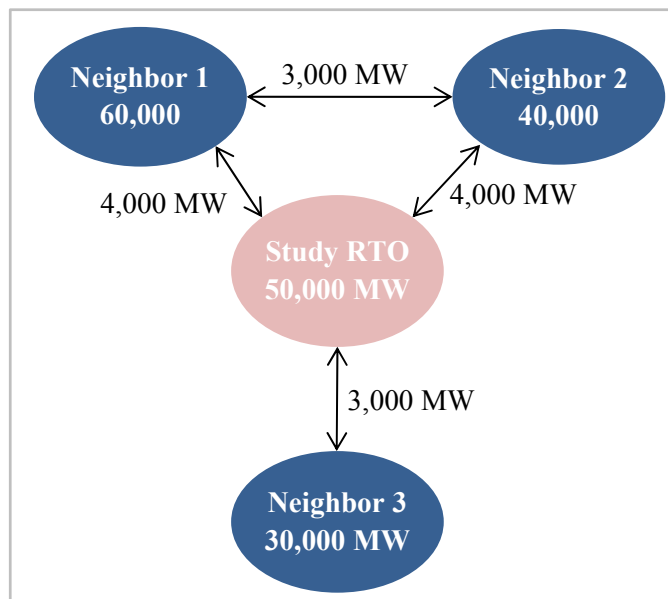
We evaluate the economic reliability implications of resource adequacy by analyzing a hypothetical RTO interconnected to three adjacent systems. This hypothetical RTO has system characteristics similar to those of many U.S. markets, but does not exactly reflect any one region in particular. By constructing 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

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

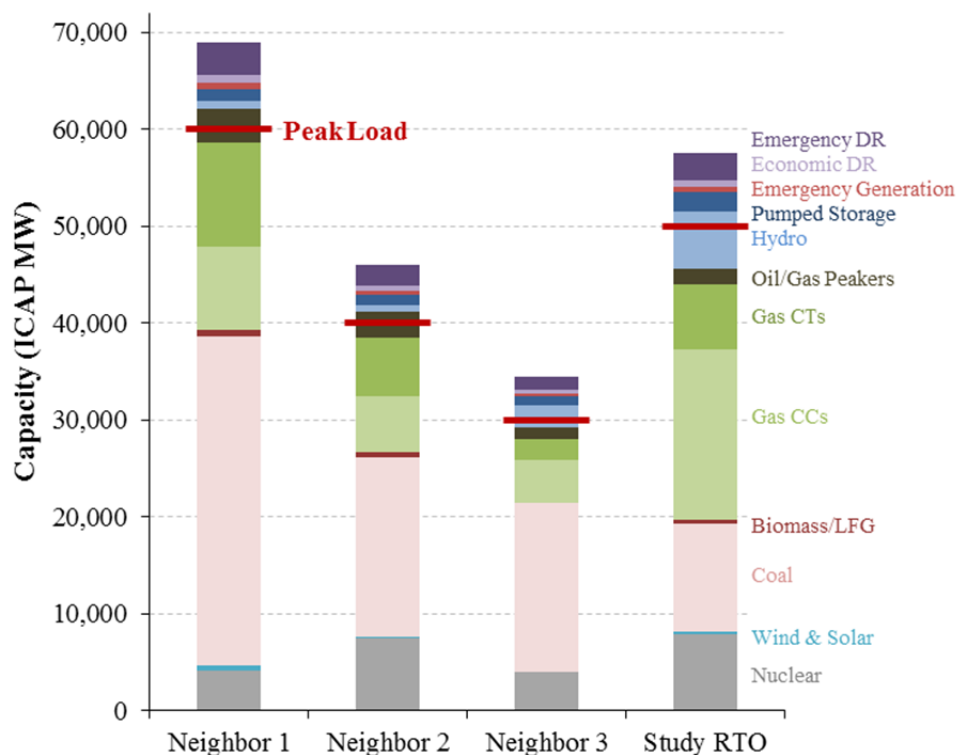
To characterize the generation and demand response resources available to meet load the simulated Study RTO and the neighboring regions, we assume resource characteristics consistent with many real-world systems. We present here a description of our assumptions and approach to modeling system supply,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

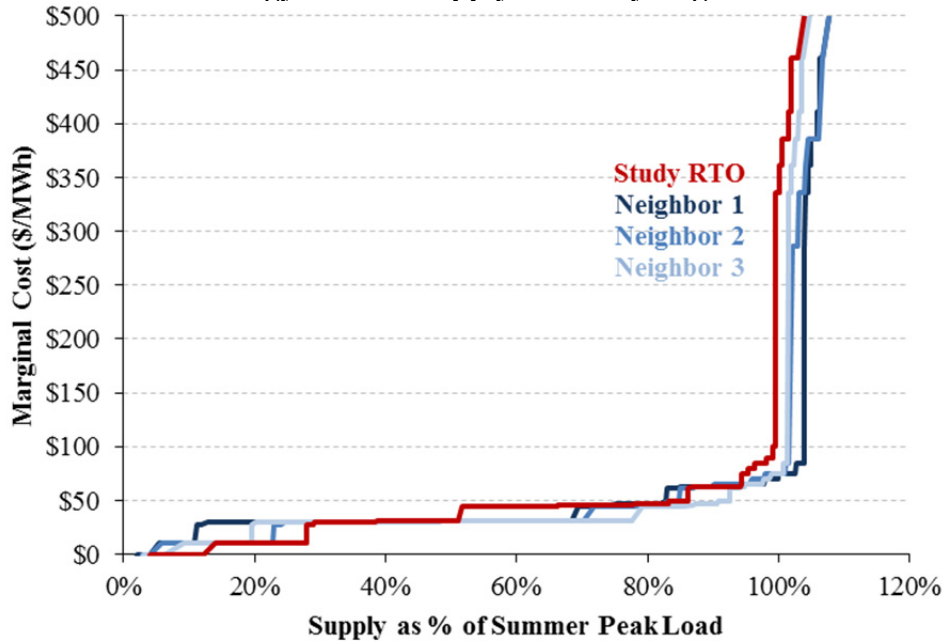
In modeling production costs for each supply resource, we assume plant costs and efficiencies that are typical for each resource type and that vary among individual units. The aggregate system supply curves for each region are shown in Figure 5 and account for fuel costs and variable operations and maintenance (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.

⁴⁷ While SERVVM 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, SERVVM 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 SERVVM 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 SERVVM 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 SERVVM 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 be 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

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

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.

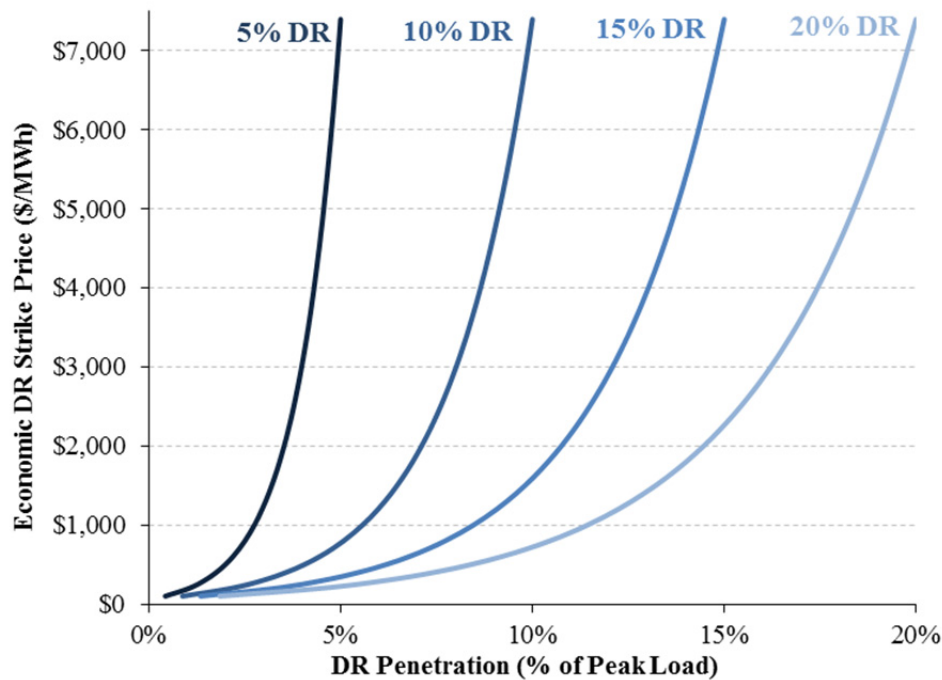
We assume that Emergency DR has the same characteristics as in the Base Case, with a \$2,000/MWh dispatch cost and a 100 hour dispatch limit (although we also test the impact of varying the dispatch limit). We model Economic DR differently, however, with Economic DR resources offering over a wide range 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

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.

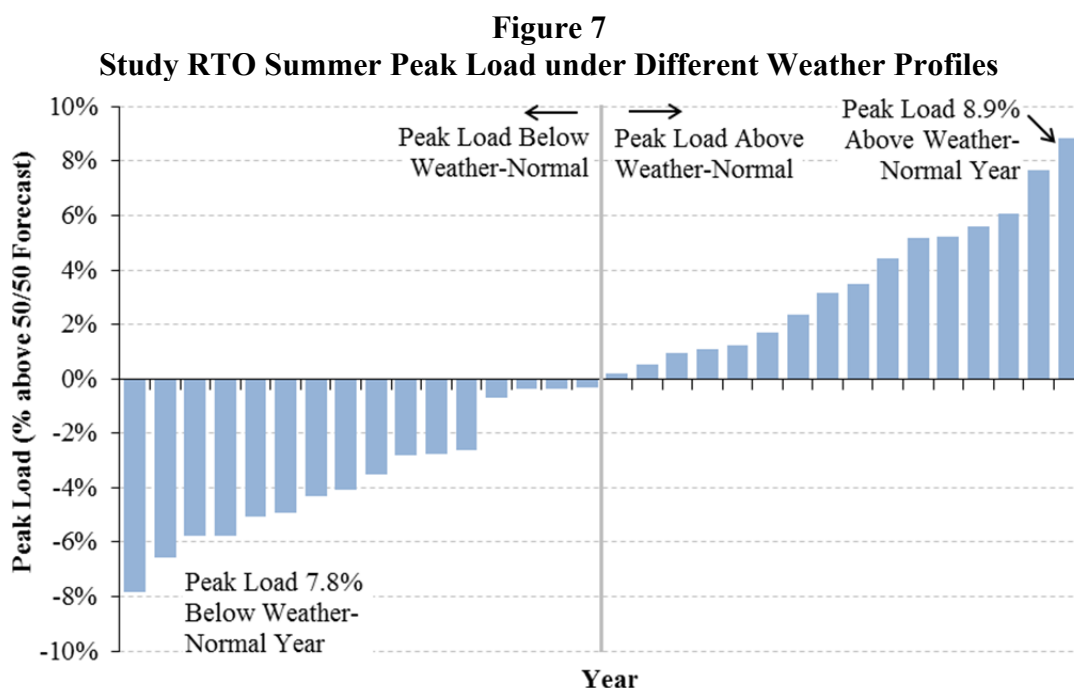
1. Weather Uncertainty

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.



Notes:

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

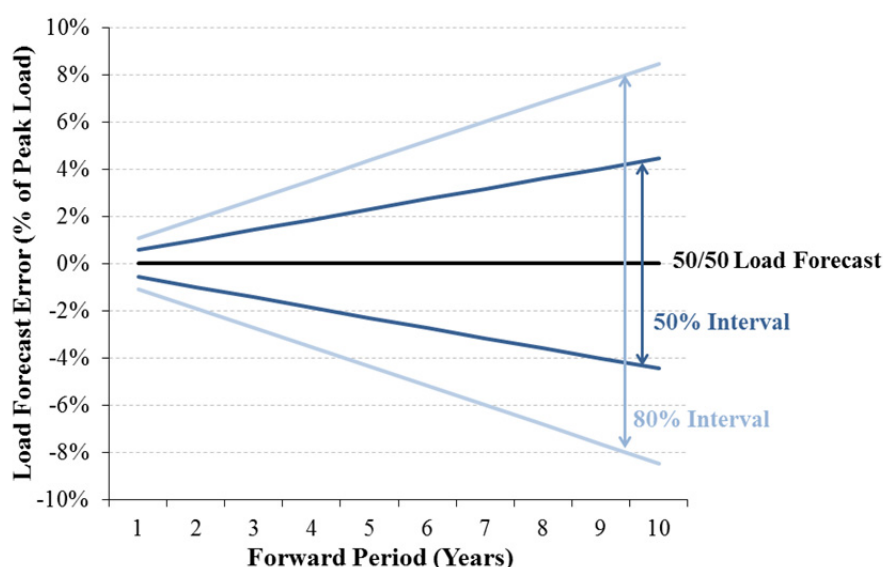
2. Economic Load Growth Forecasting Uncertainty

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

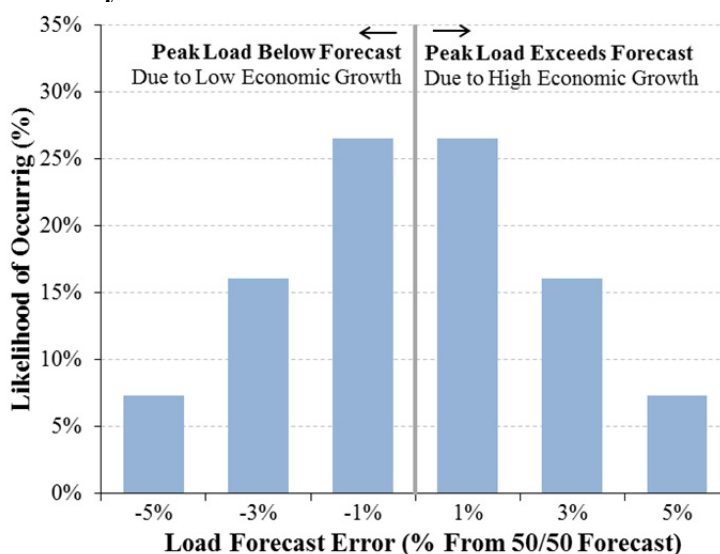
⁶⁷ See CBO (2012).

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, SERVVM 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

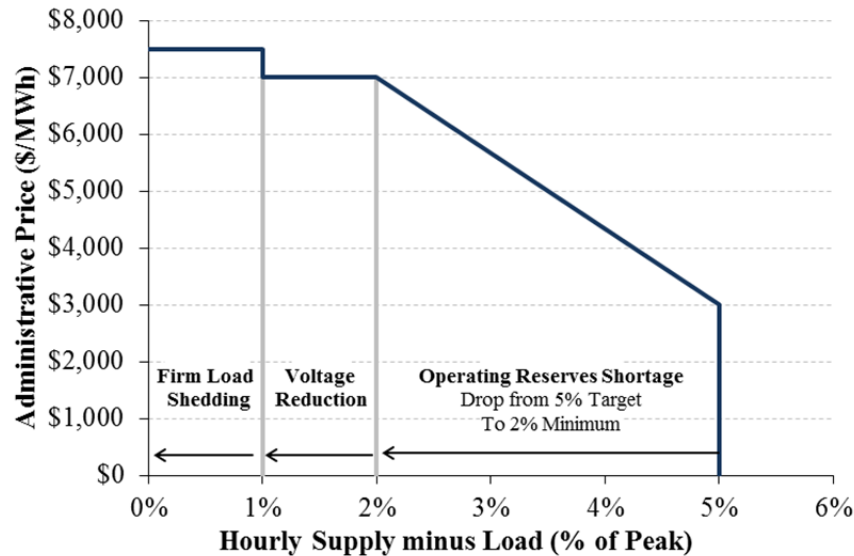
Once operating reserves are at the minimum level of 2%, the system operator will implement: (a) a system-wide voltage reduction that is assumed to achieve a 1% reduction in load at a marginal system cost of \$7,000/MWh; and finally, as a last resort, (b) curtailments of firm load at a marginal system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

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 <i>(\$/kW-yr)</i>	Heatrate <i>(btu/kWh)</i>
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

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.

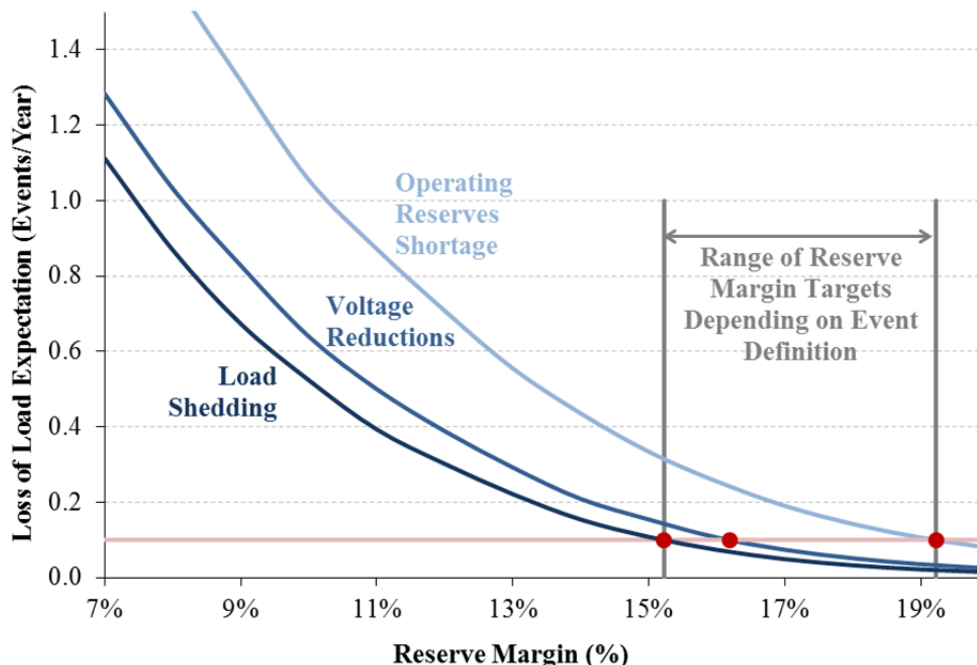
⁸¹ In this figure and the entirety of this study, we calculate the reserve margin on an ICAP basis, assuming a capacity value 100% of nameplate capacity for all resources, including both economic and reliability DR, with the exception of renewable generation, which we assign capacity value of 15% of 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

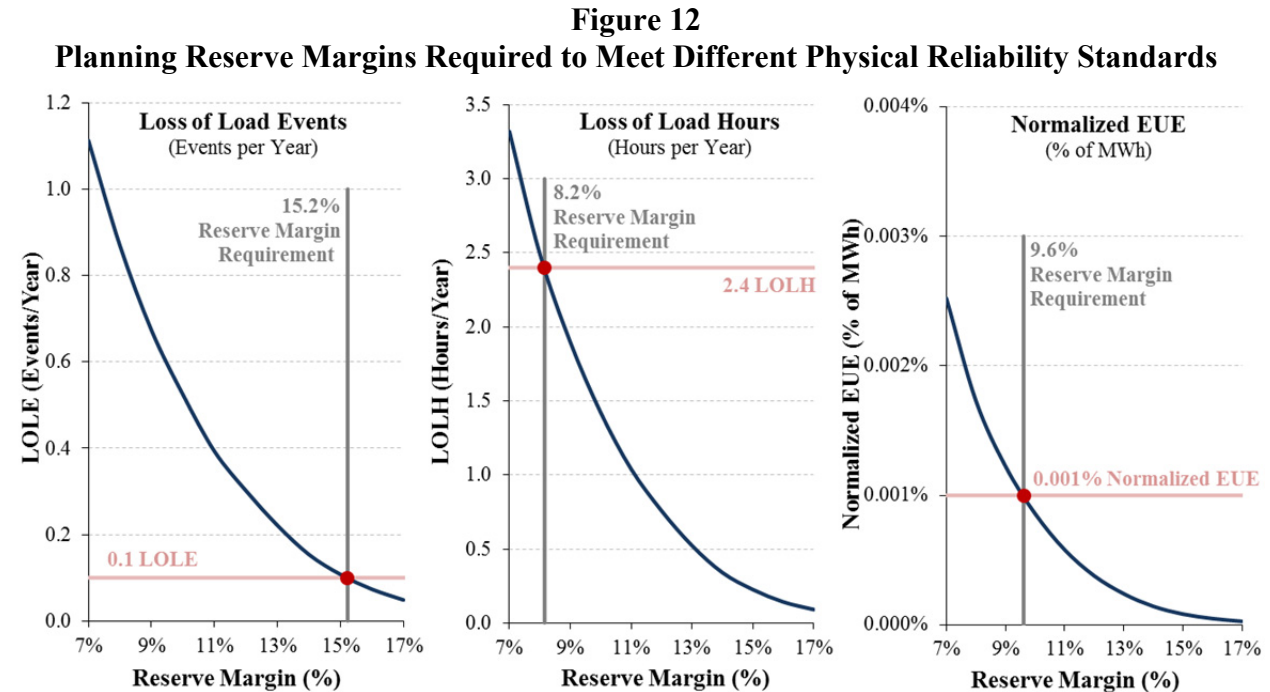
This analysis shows that a 0.1 LOLE standard is a much more stringent reliability standard than 2.4 LOLH for the Study RTO, despite the fact that these two standards are both commonly referred to as “1 day in 10 years.” The magnitude of the difference between the two standards

Continued from previous page

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.1 and 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.

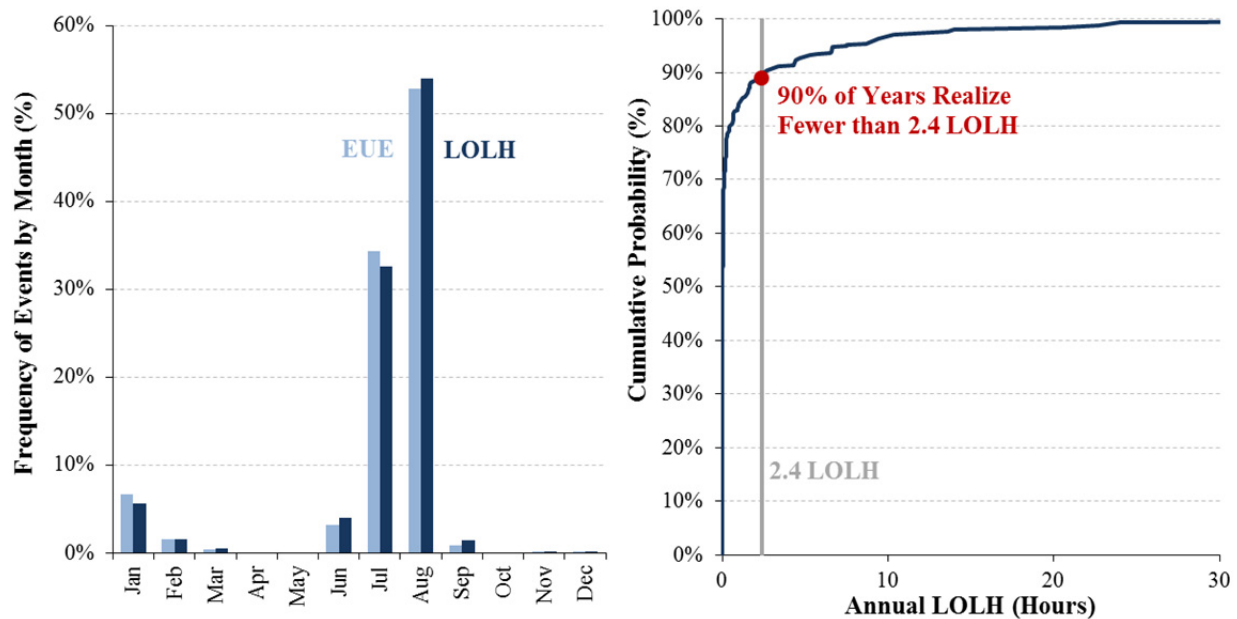


Notes:

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.

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.

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 obtain 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

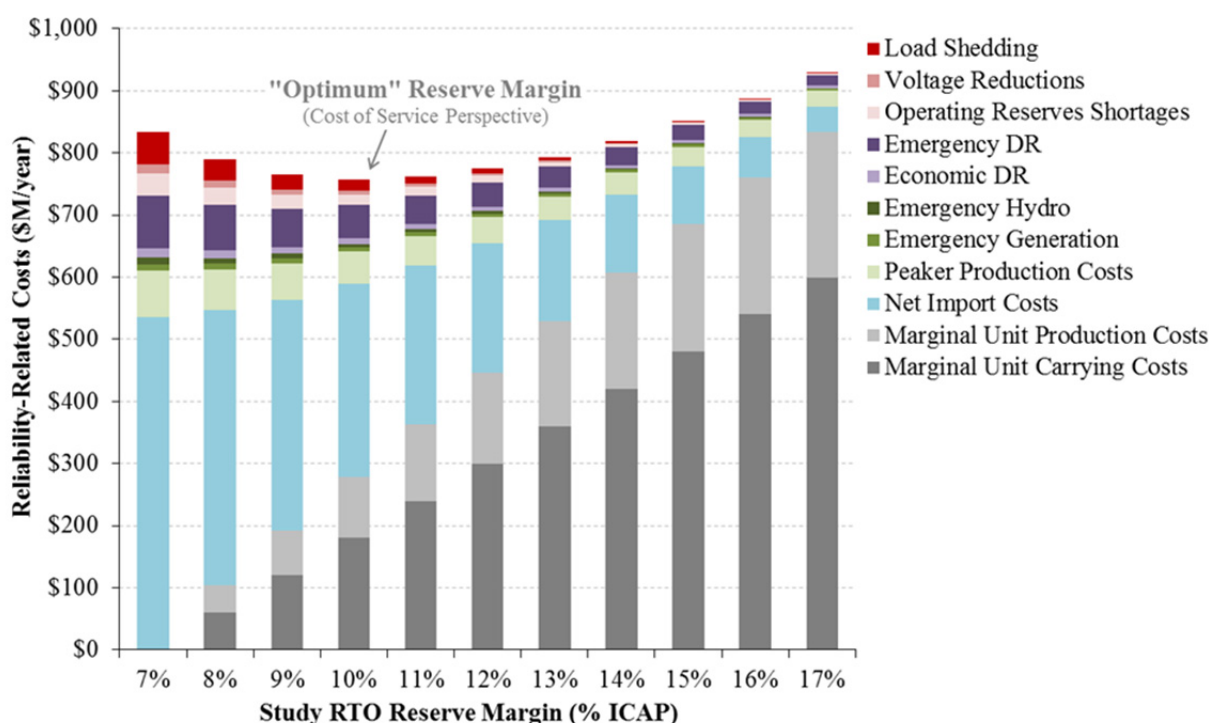
⁹³ See additional discussion of these impacts in Sections III.A.3 and III.B.2.

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

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.

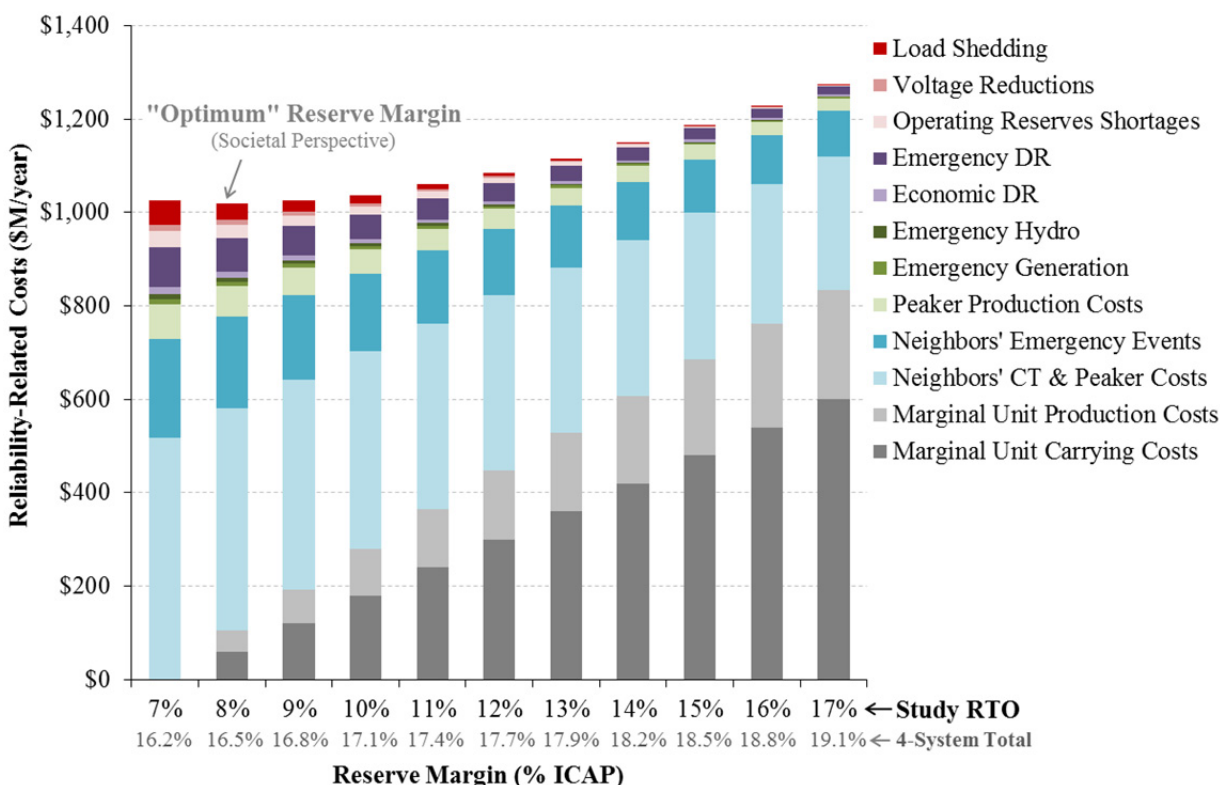
⁹⁸ Note that we add capacity only inside the Study RTO and not in any of the Outside Regions. The total reserve margin for the four systems combined changes only because capacity is being added in the Study RTO. The installed capacity in the neighboring regions is held constant at the original 15% reserve 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 (MW)	Peak Load		Reserve Margin	
		Non-Coincident (MW)	Coincident (MW)	Non-Coincident (%)	Coincident (%)
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 85th, 90th, and 95th 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 85th 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.

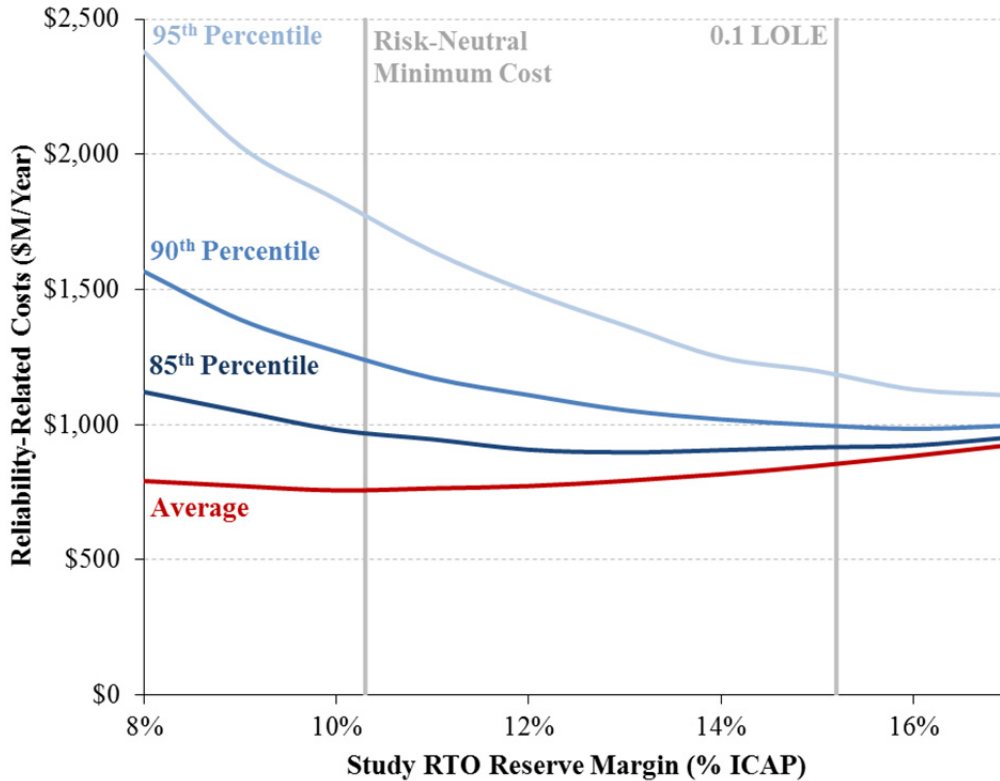
Considering the much higher cost uncertainty exposure at lower reserve margins, many planners and policy makers may wish to set planning reserve margins above the risk-neutral economic optimum. In our sample system, even a several percentage point increase in the target reserve margin would only slightly 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.

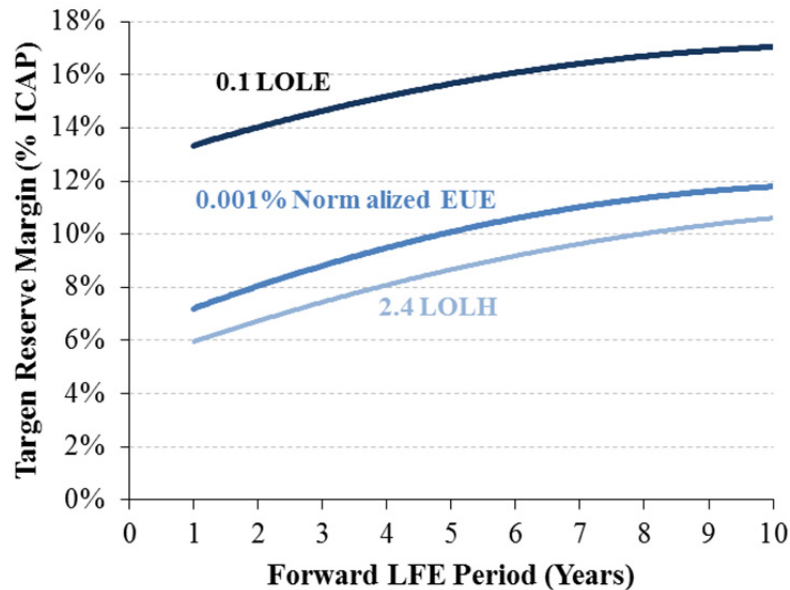
We examine the implications of revising the forward planning period on the reserve margin standard and total system costs by adopting alternative economic forecast error assumptions consistent with different forward periods as documented in Section II.D.2 above. Increasing the forward period increases 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:

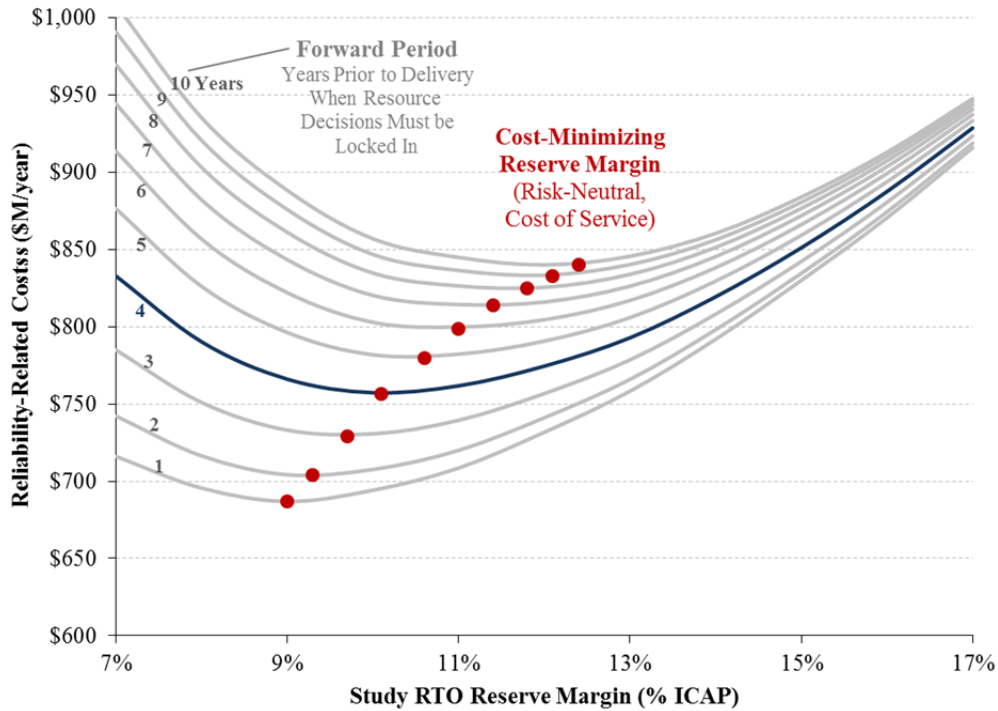
Study RTO reliability-based reserve margin vs. forward period.

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% Inertia	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

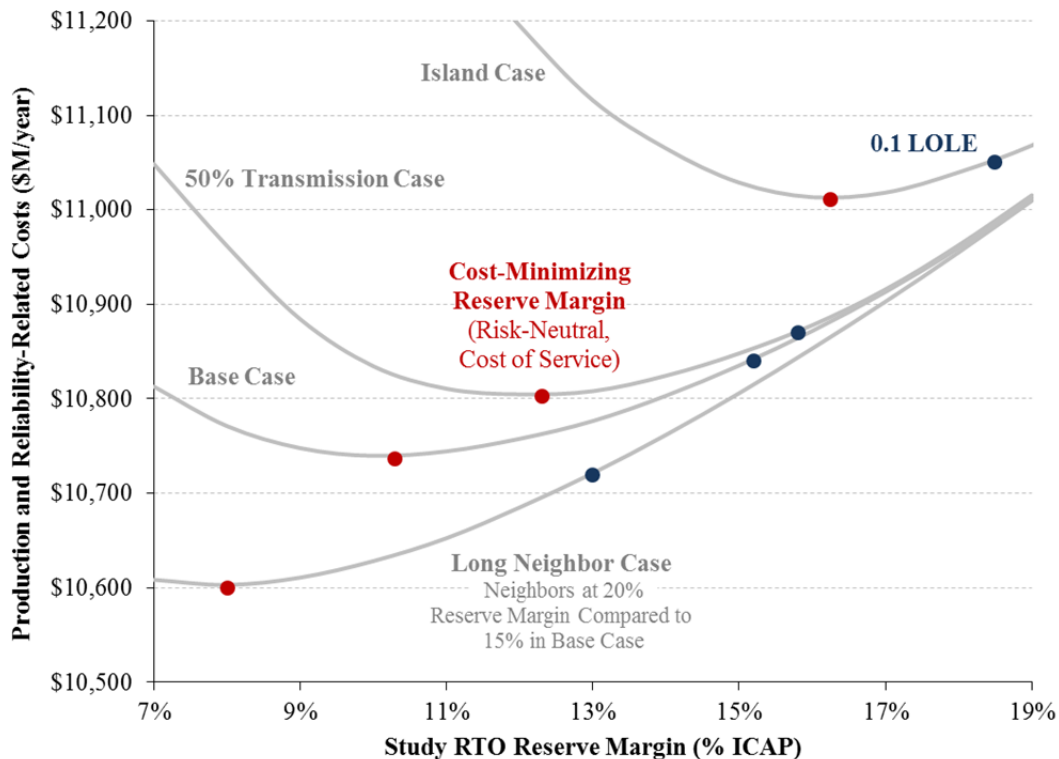
Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%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

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

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

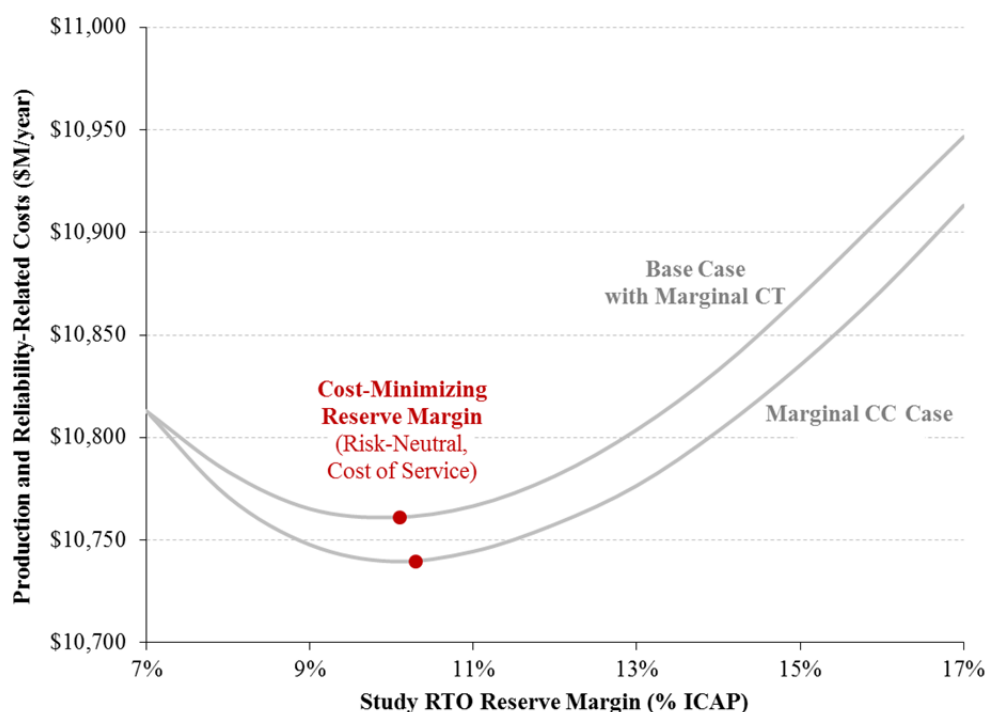
¹¹² More generally, a thorough system planning effort could evaluate many types of resources to determine which is the most economic. Alternately, in a deregulated market-based environment, merchant suppliers would determine which type of resource to build by forecasting the profitability of each type 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

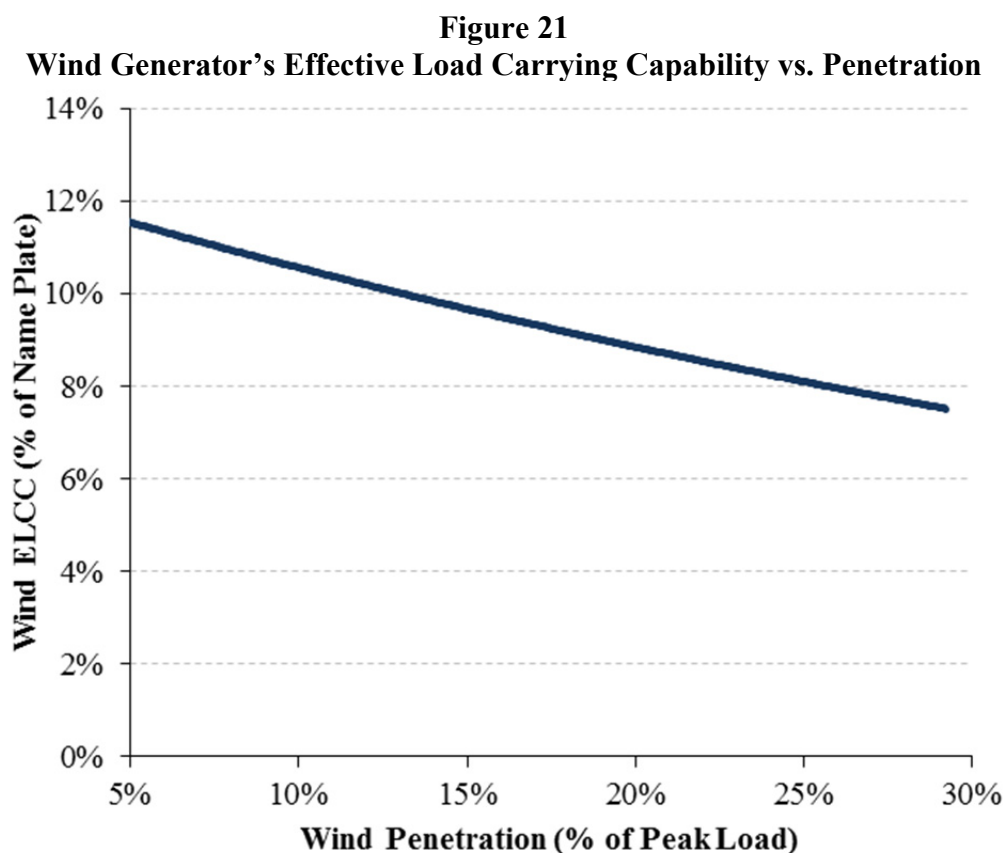
¹¹⁵ For example, PJM assigns intermittent resources a capacity value equal to the capacity factor during summer peak periods over the previous three years, or a generic value of 13% or 38% for new wind and solar resources respectively. See PJM (2010). For a wider survey of RTO practices for assigning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



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.

15% Reserve Margin
(Including all Gen and DR)

Max Load w/o Calling DR
(Reserve Margin minus DR, Emergency Hydro, and Operating Reserves)

DR Calls at 10% Penetration
Approximately 5, 25, or 122 Hours with Mild, Normal or Extreme Weather

Hourly Load (% of Weather-Normal Peak)

Number of Hours

Extreme Weather

Normal Weather

Mild Weather

0% DR

5% DR

10% DR

15% DR

20% DR

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.

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

66

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

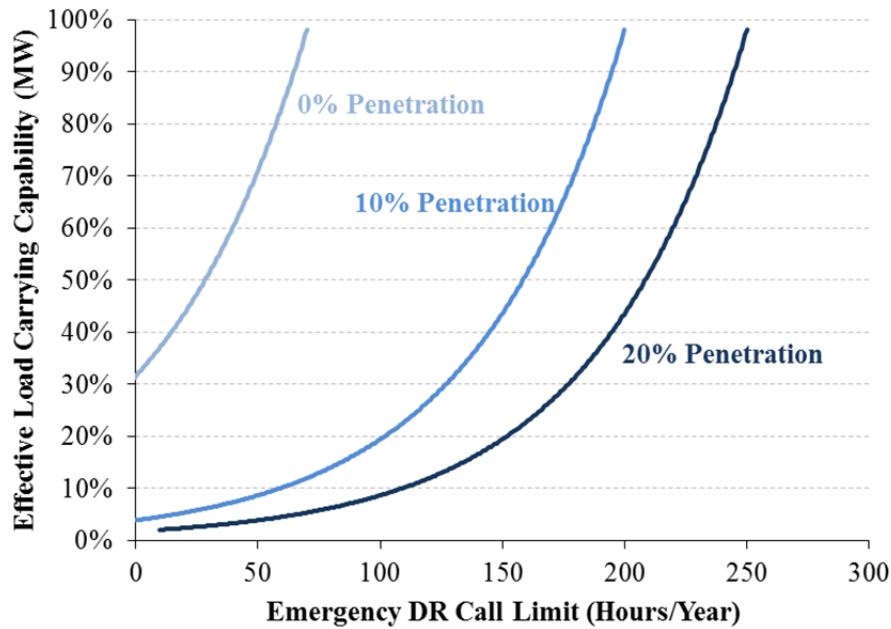
Figure 23 shows the effective load carrying capability (ELCC) of Emergency DR resources. The ELCC of Emergency DR increases with the dispatch price and decreases at higher DR penetration levels. We calculate ELCC as in Section III.B.4 above by determining the quantity of Emergency DR that would have 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:

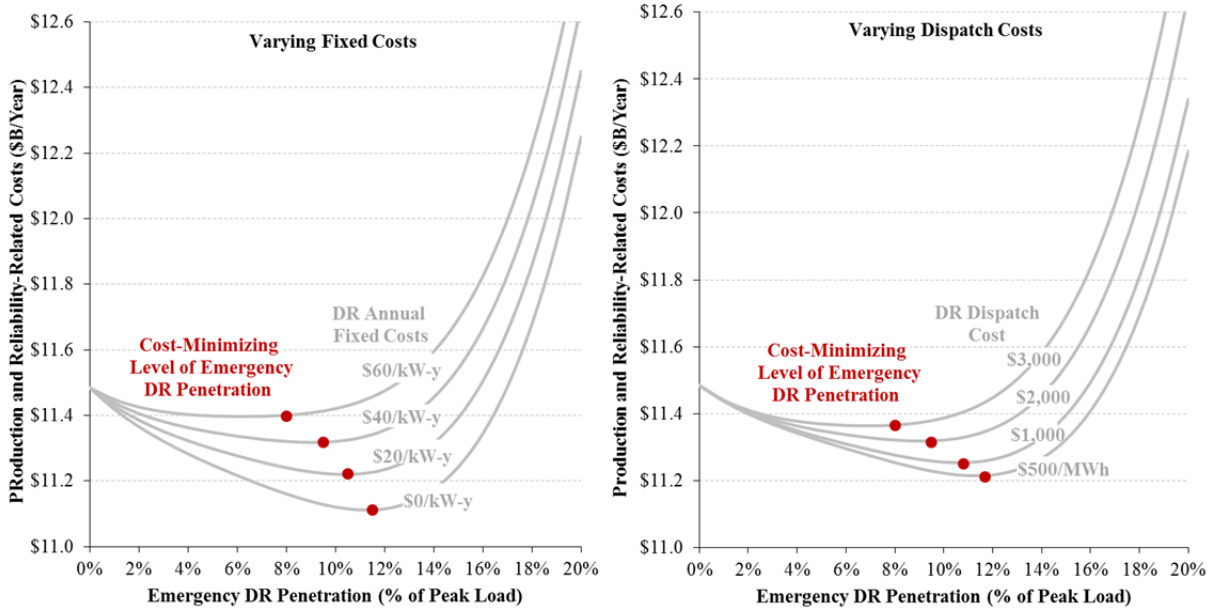
Study RTO reserve margin fixed at 15% with CTs displaced by increasing DR.
ELCC of 25% indicates that 4 MW of DR would be needed to achieve the same reduction in LOLE as adding 1 MW of CTs.

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.

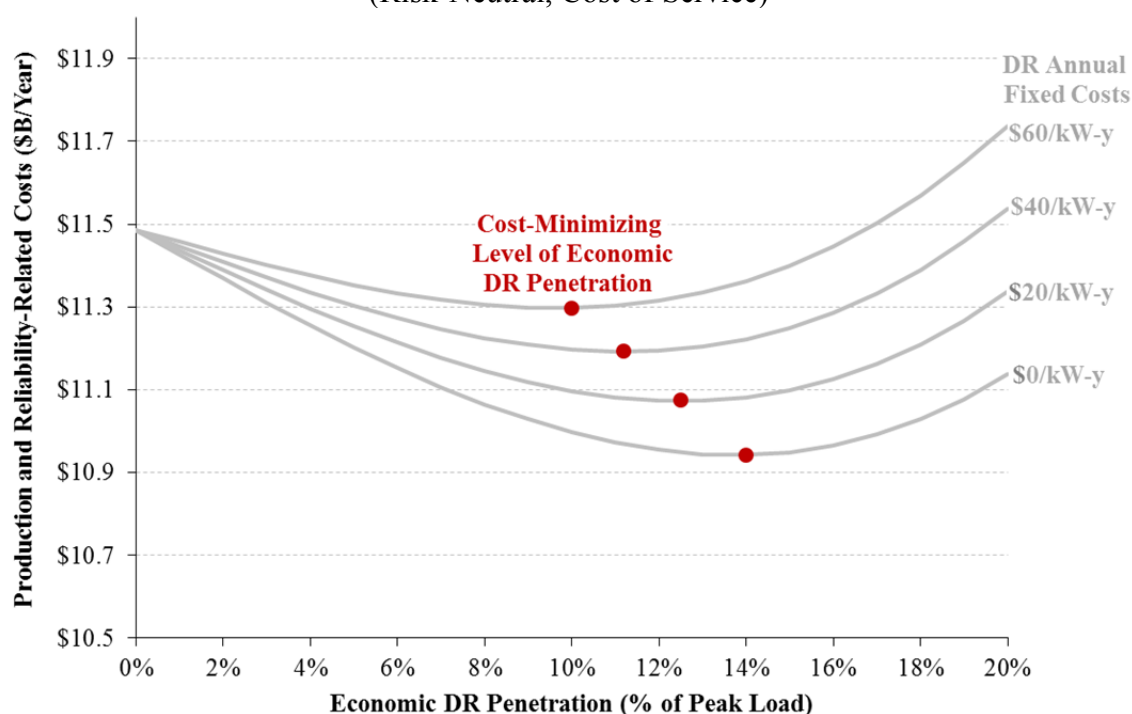
The simulation results highlight the complex role of demand response in reliability planning. DR penetration levels, the design of the products (including dispatch limits and price), and the system load shape all affect the economic and reliability value provided by these resources. The results also 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
<i>All Emergency Event Costs</i>	<i>9.2% - 12.1%</i>	<i>Base</i>	<i>50% or 200% Base</i>
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

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

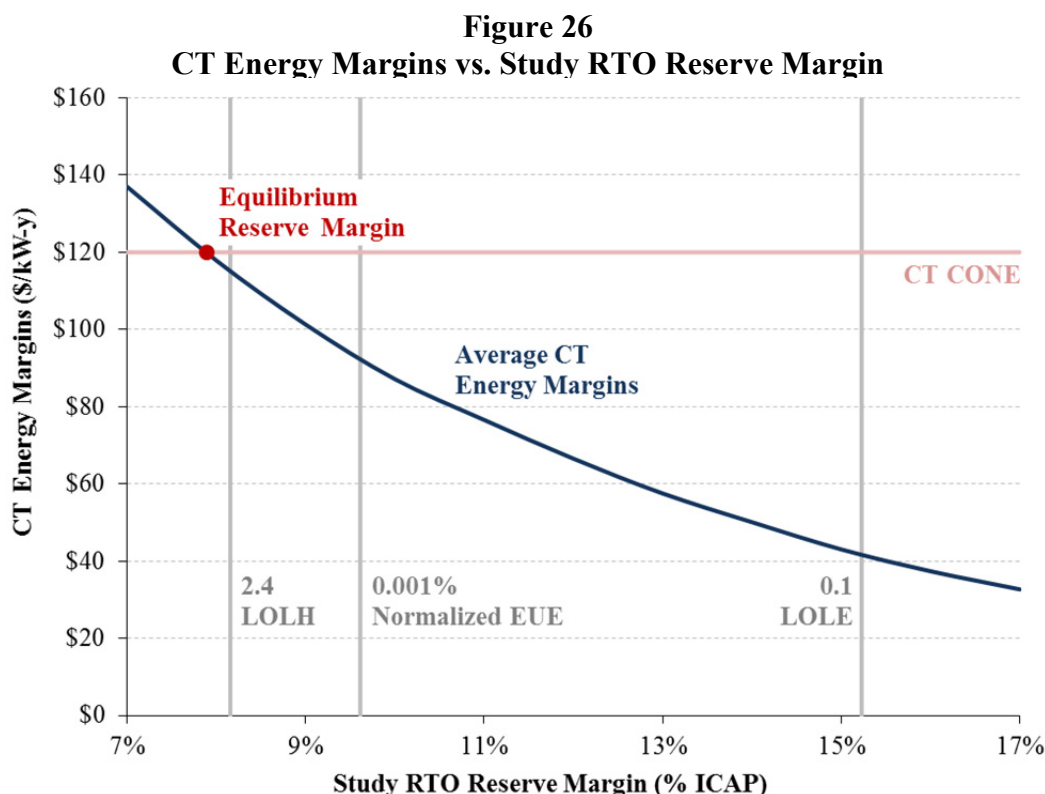
The figure shows that average annual energy margins are high at very low reserve margins because tight supply conditions create high energy prices and more frequent price spikes. Under such conditions, an energy-only market would attract additional investments because suppliers would expect to earn on 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.



Notes:

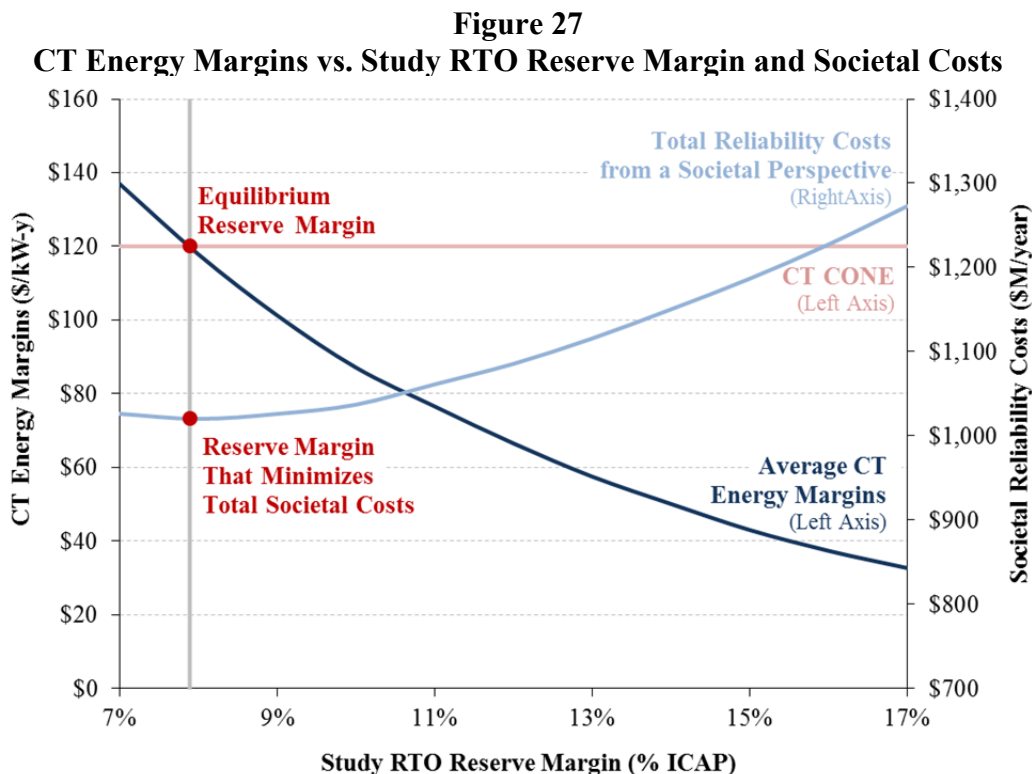
CT energy margins in the Study RTO are from the Base Case simulation.

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



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

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

Continued from previous page

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

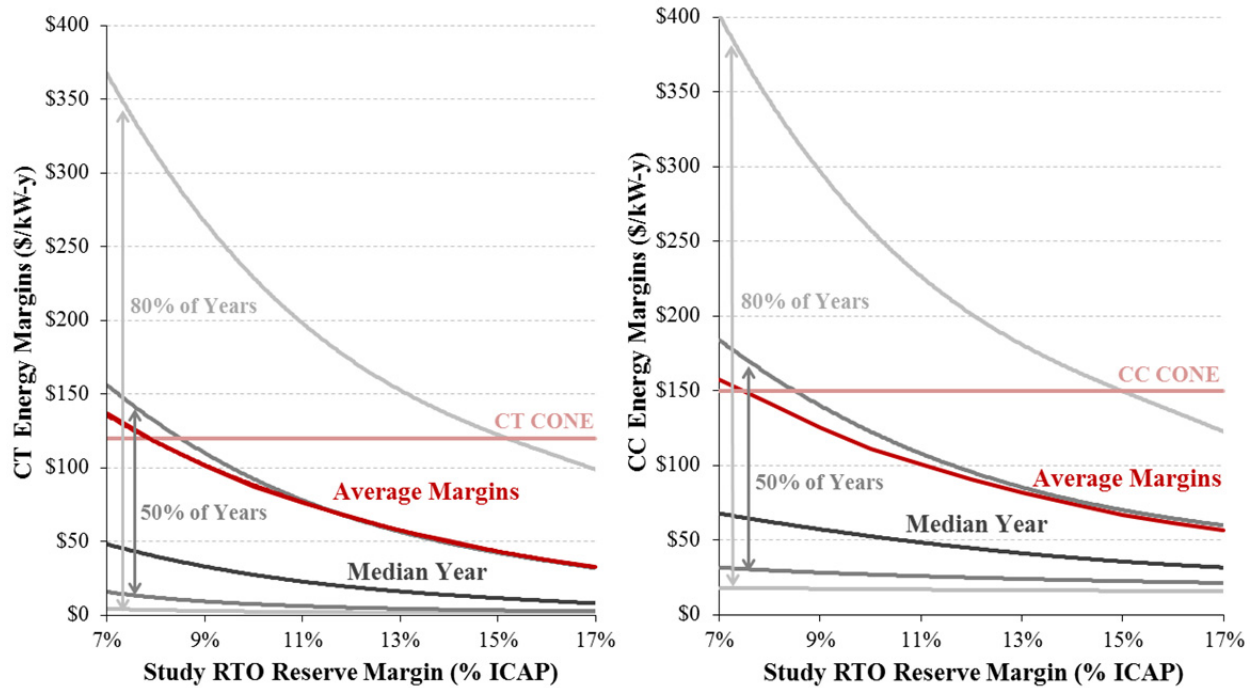
Figure 28 summarizes annual energy margins earned on average for a new CT (on the left) and a new CC (on the right) at different reserve margins. The figure also shows the range of annual energy margins that would be realized in spot energy markets due to uncertainties such as weather, load growth, hydro 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.

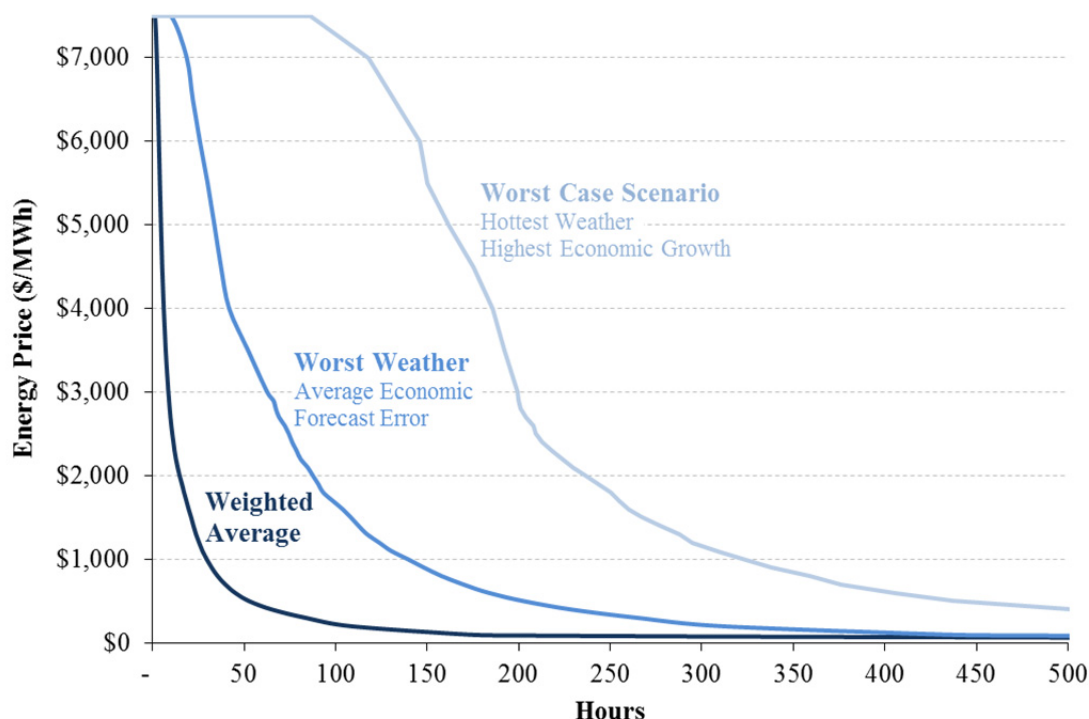
Gray lines represent the 10th, 25th, 50th, 75th, and 90th percentile estimates of spot energy margins (*i.e.*, net revenues earned in spot energy market without forward contracting or other risk mitigation).

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

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	Realized Real-Time Spot Prices	Delta
	<i>(\$/MWh)</i>	<i>(\$/MWh)</i>	<i>(\$/MWh)</i>
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

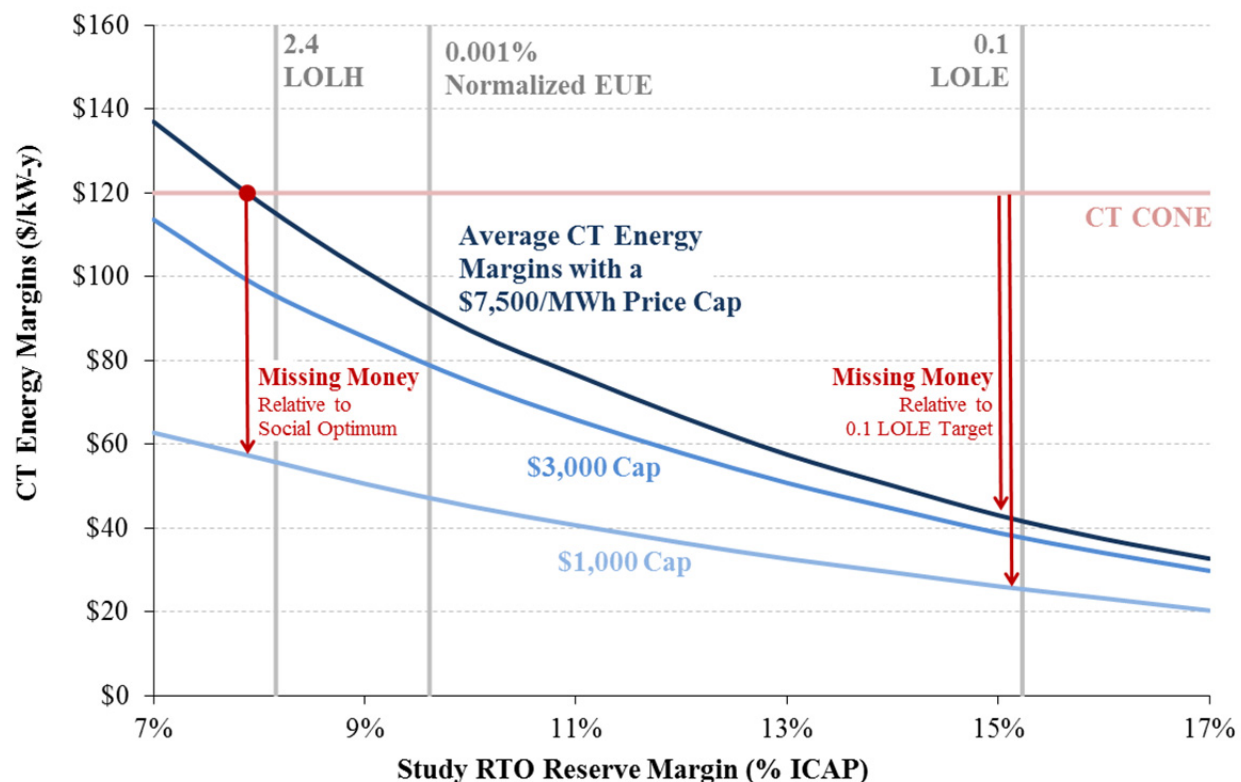
The Base Case assumes that energy prices can rise up to the VOLL-based energy price cap of \$7,500/MWh. As explained above, this VOLL-based price cap, combined with an efficient scarcity pricing mechanism tied to marginal system cost creates efficient real-time energy market price signals that accurately 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.

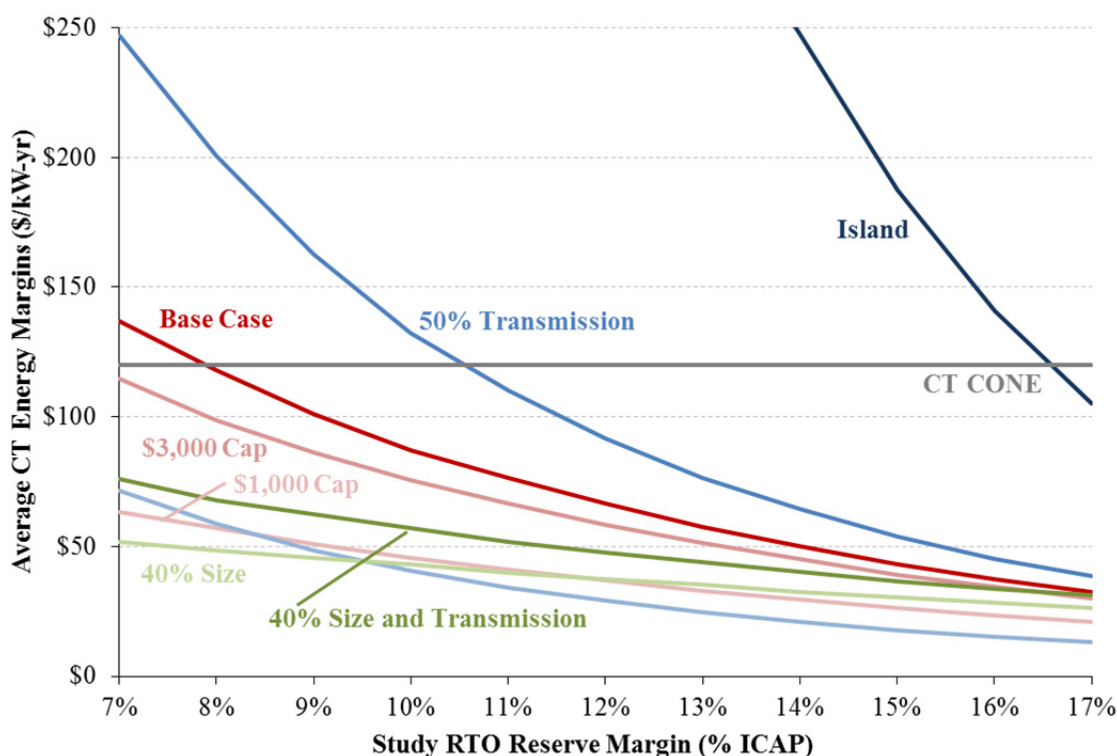
5. Implications of Varying System Conditions and Study Assumptions

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

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

Continued on next page

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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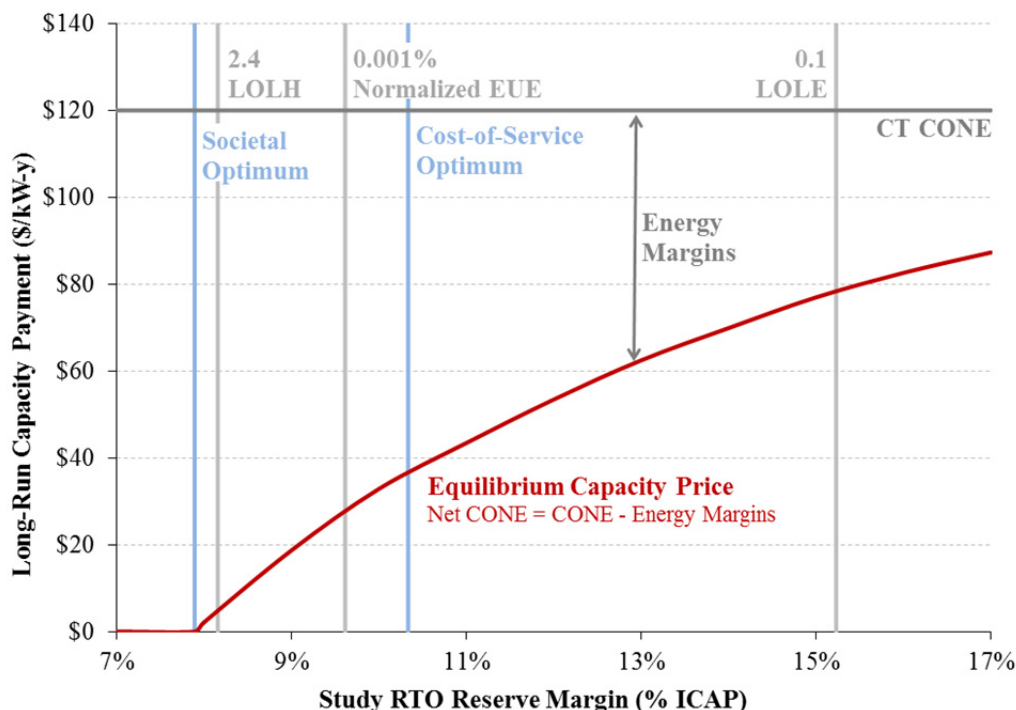
market prices that support sufficient investment in the Alberta energy-only market; and Newell *et al.* (2012) discussing a range of options, with and without a capacity market, to address a missing money problem in the Texas energy-only market.

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

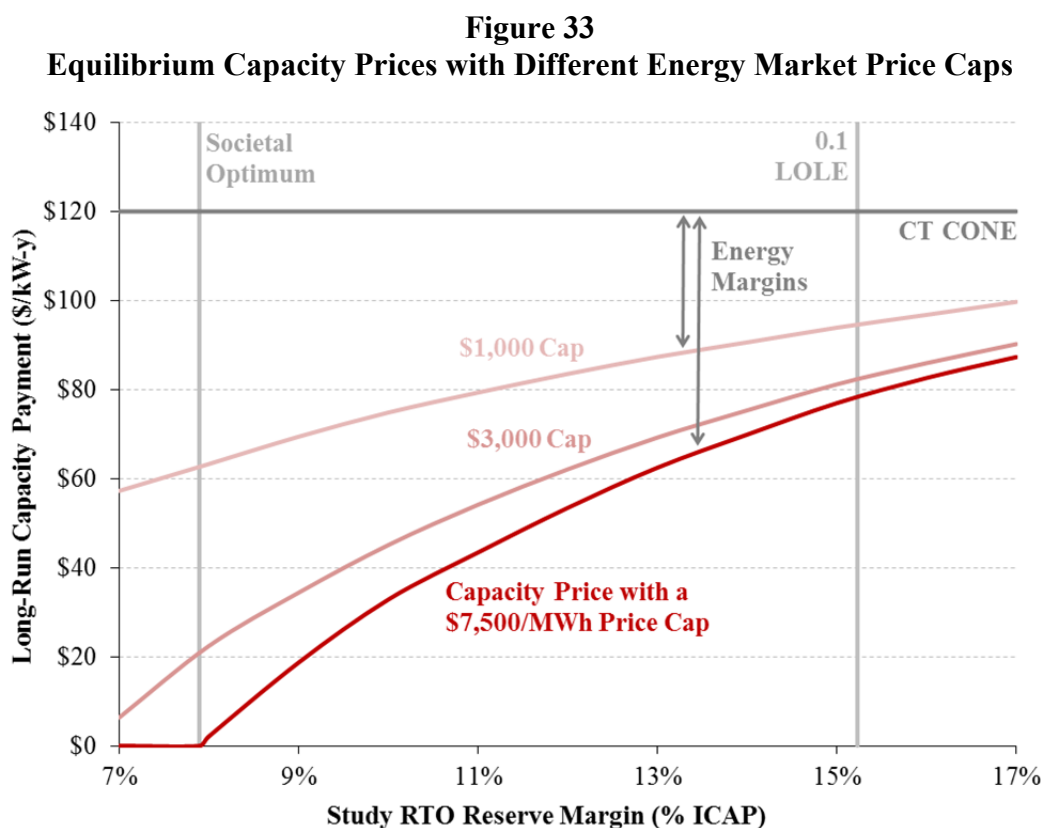
Because capacity prices must be equal to Net CONE over the long-run to sustain a particular reserve margin, any factors that cause anticipated energy margins to drop will also cause capacity prices to increase if the reserve margin is to be maintained. Figure 33 illustrates this effect for our Study 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.



Notes:

Equilibrium capacity price is at CT Net CONE.

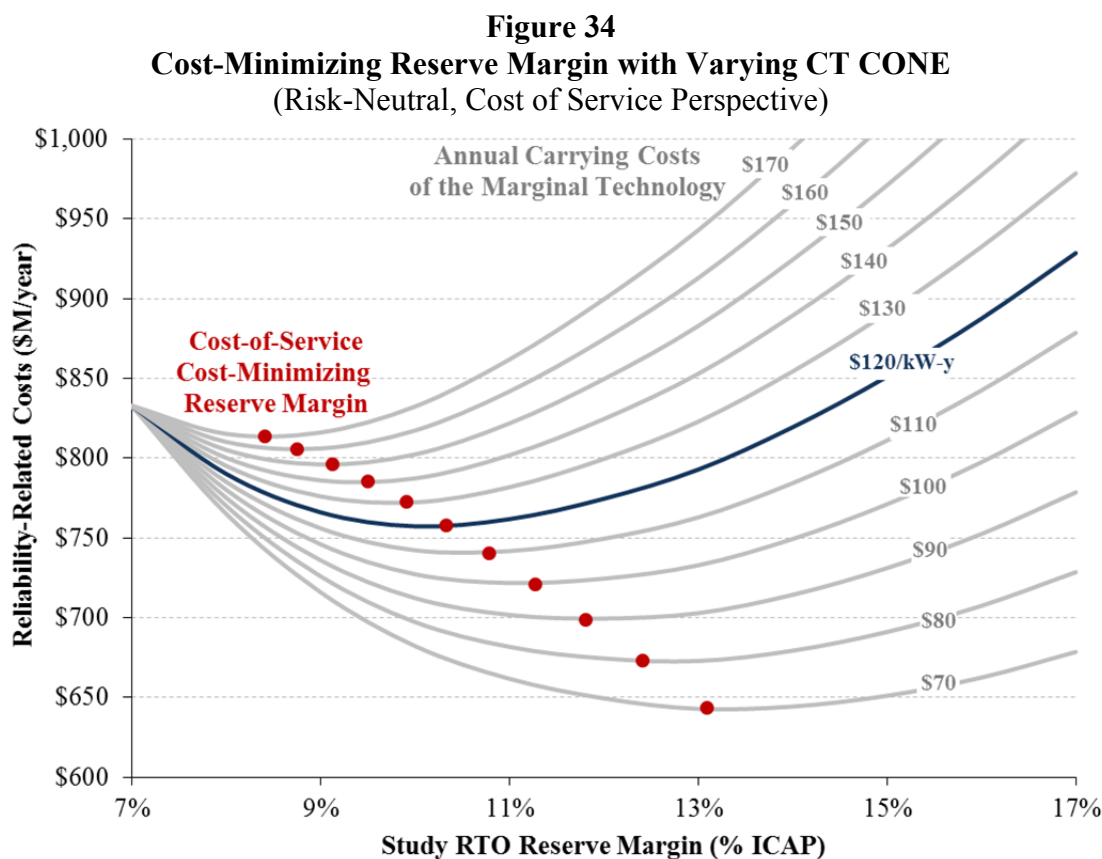
Calculated at price caps of \$7,500/MWh (Base Case), \$3,000/MWh, and \$1,000/MWh.

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%.



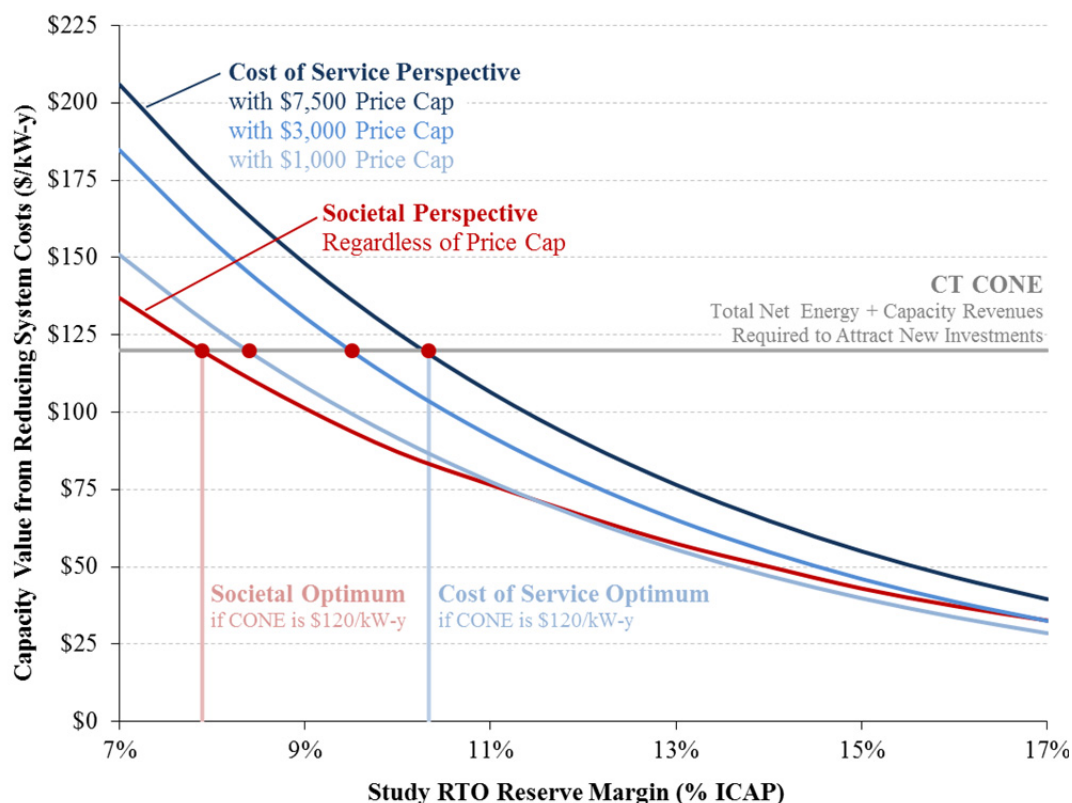
Notes:

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.

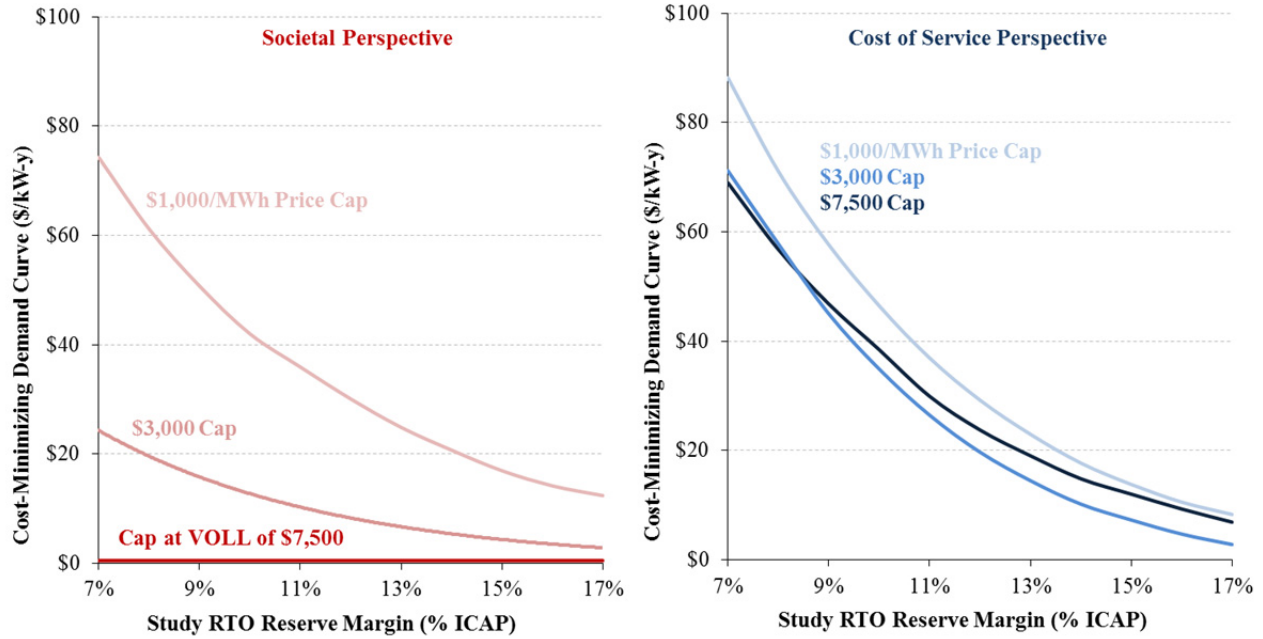
Within a capacity market, one can translate this value-of-capacity calculation into a cost-minimizing demand curve for capacity by subtracting out the portion of total costs that suppliers would be able to cover through energy margins as shown in Figure 36. This demand curve for capacity would procure 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

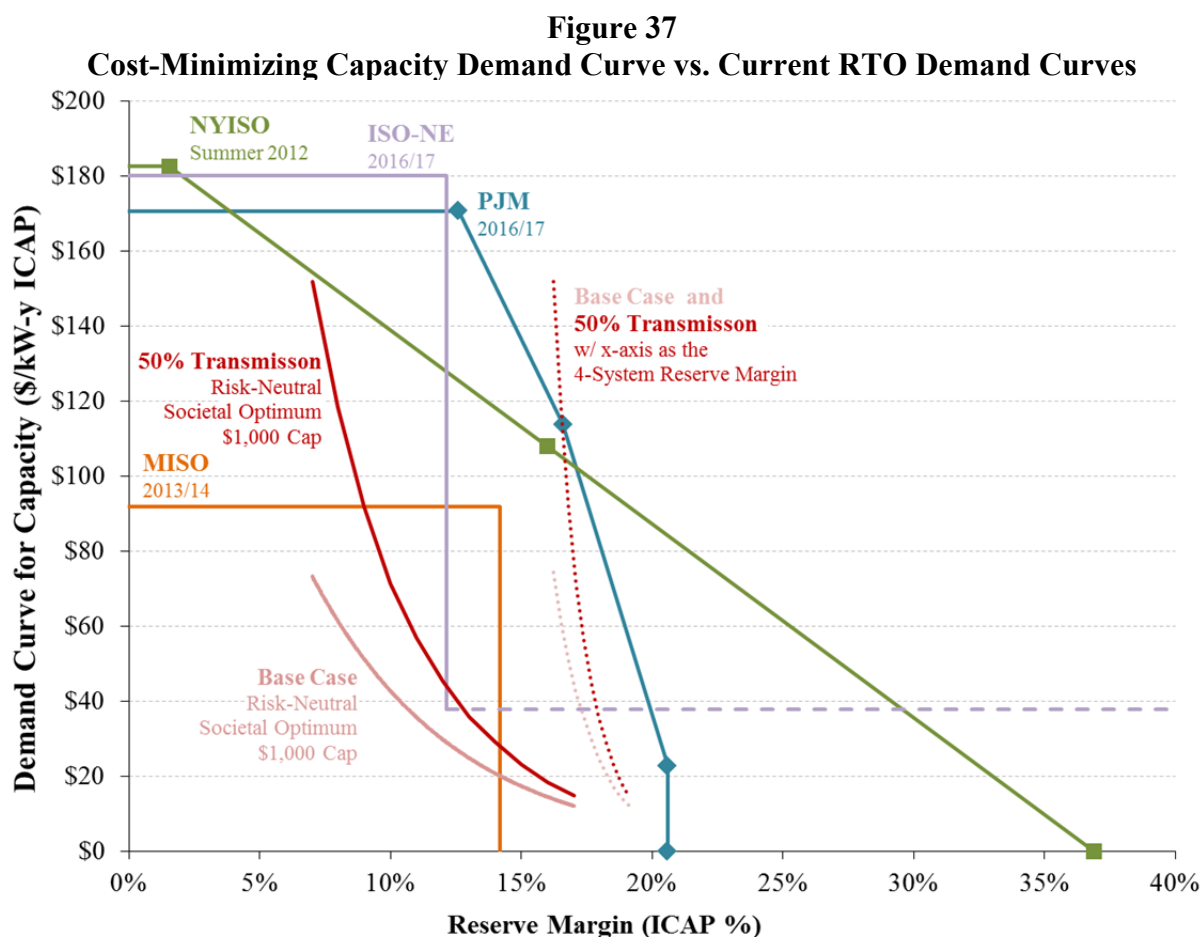
Figure 37 compares the cost-minimizing demand curves calculated in the previous section to demand curves that are currently being used in the capacity markets in NYISO, ISO-NE, PJM, and MISO. We compare the demand curves that would be calculated under the Base and 50% Transmission Cases from the risk-neutral 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



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.

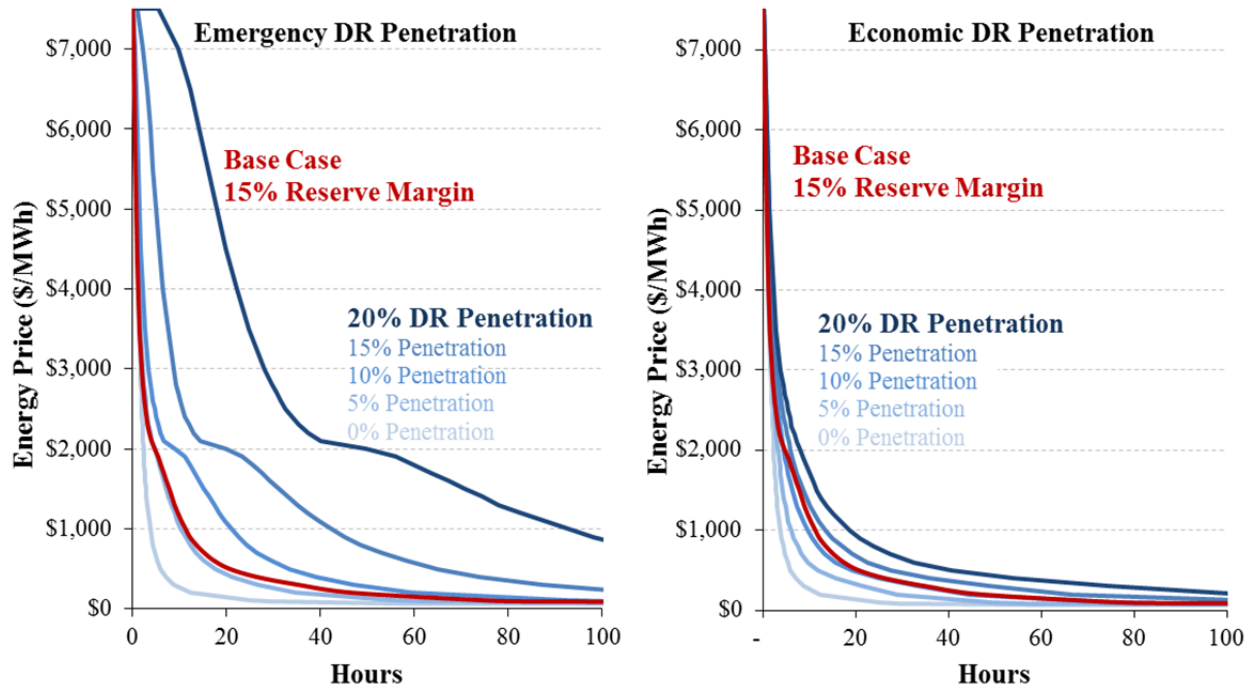
1. Energy Market Impacts

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

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.

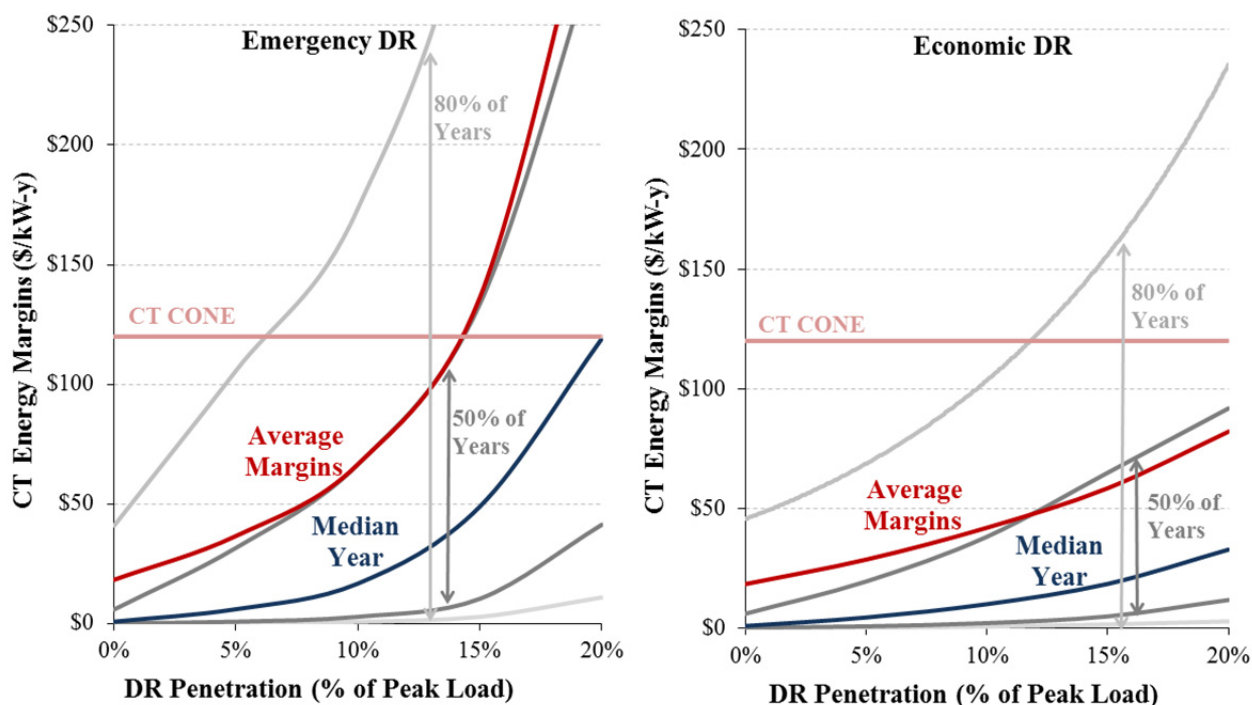
¹⁵¹ For an analysis of how DR displacing generation may increase DR call hours in PJM over the coming years, see Newell and Spees (2013).

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

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.

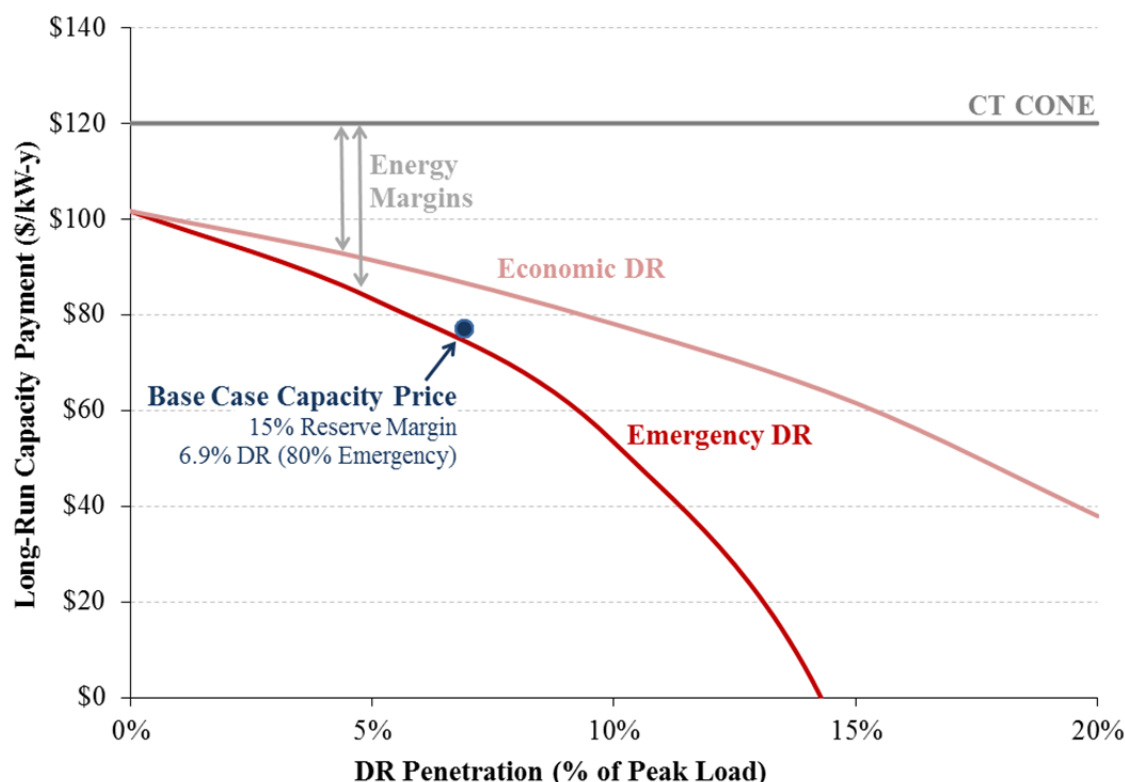
¹⁵⁴ Note that DR suppliers have an annual “net interruption cost” that would be calculated very similarly to generator energy margins but can actually be positive or negative in total value. The value of the “net interruption cost” is the energy price when called minus the true strike price. If the energy 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

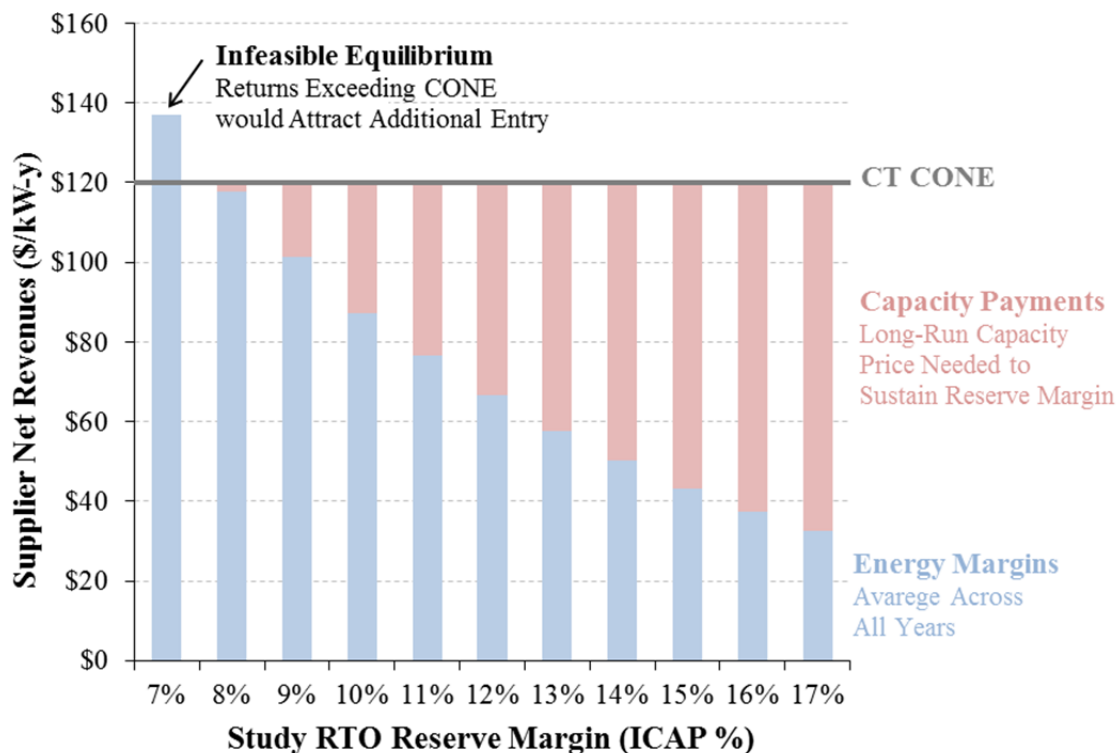
¹⁵⁹ With the primary inefficiency stemming from the lack of an efficient call order among resources whose strike price is near to or exceeds the energy market cap. PJM’s current cap on the energy component of the LMP is \$1,500/MWh, as of October 2012 and will rise to \$2,700/MWh by June 2015, see PJM (2012b), p. 162.

¹⁶⁰ Average energy margins and capacity prices are calculated as explained in Sections IV.A.1 and 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:

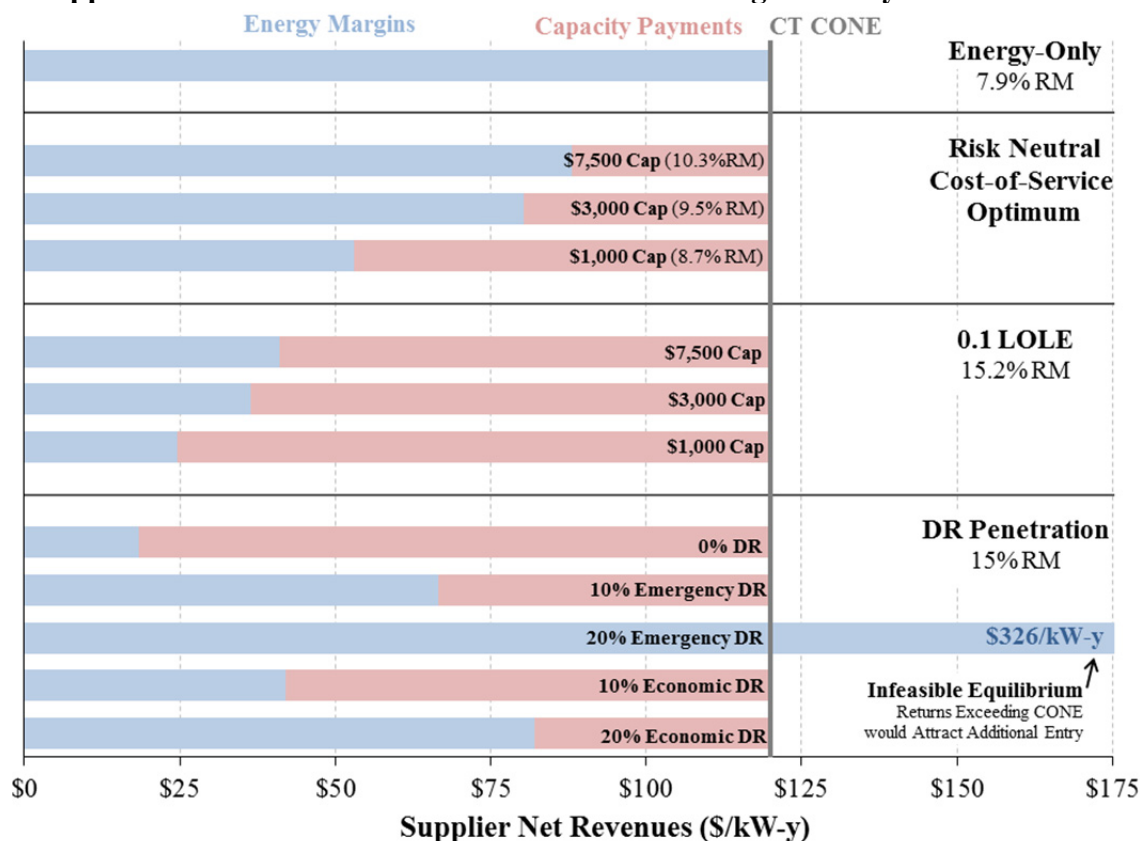
Study RTO Base Case results, see Sections IV.A.1 and IV.B.1 for calculation details.

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

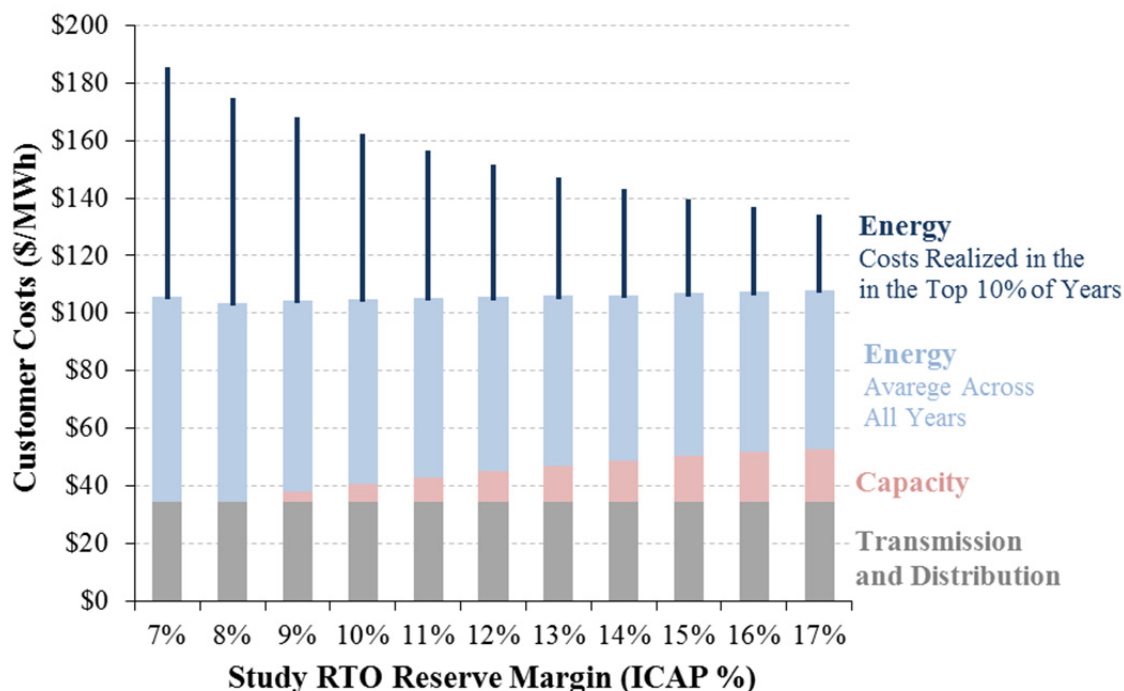
Total customer costs are minimized at the risk-neutral, “societally-optimal” reserve margin of 7.9%, consistent with the discussion in Section IV.A.2 above. Unlike individual suppliers’ equilibrium net revenues, customer costs vary with the reserve margin even in equilibrium conditions. This is because 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).

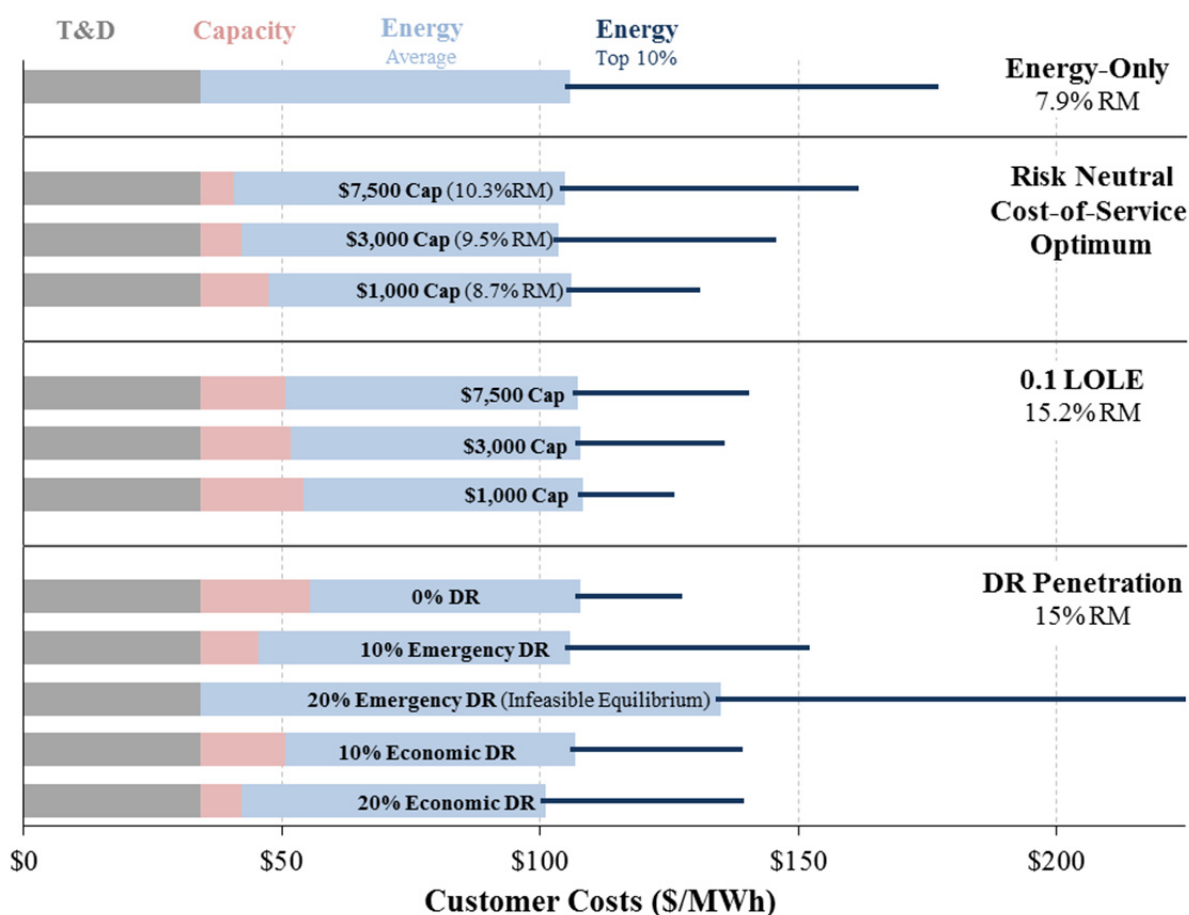
Average T&D costs are a 2011 U.S. national average, see EIA (2013b).

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 <i>First</i> 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	SERVIM	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 SERVVM 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, SERVVM 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.

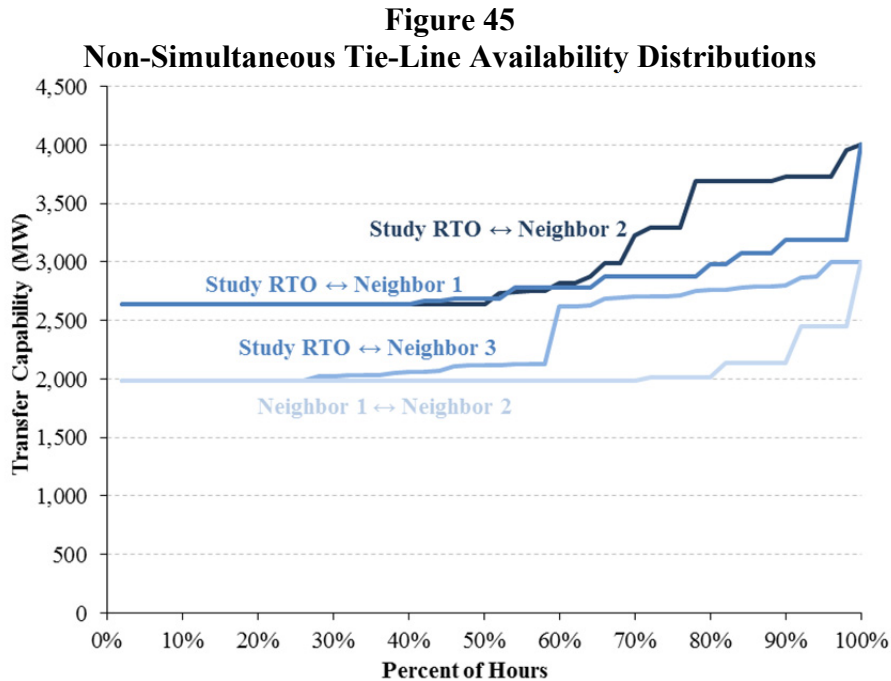
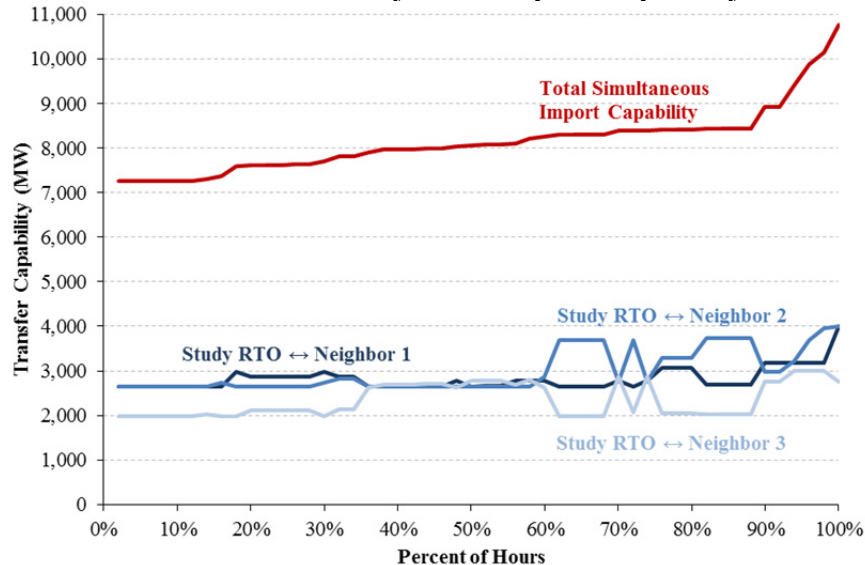


Figure 46
Simultaneous Study RTO Import Capability



2. Thermal Resource Forced and Maintenance Outage Assumptions

We provide here additional detail regarding how SERVVM 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, SERVVM does not use an average outage rate for each unit to approximately capture unit availability. Instead, SERVVM 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 SERVIM, 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, SERVIM 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 SERVIM 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

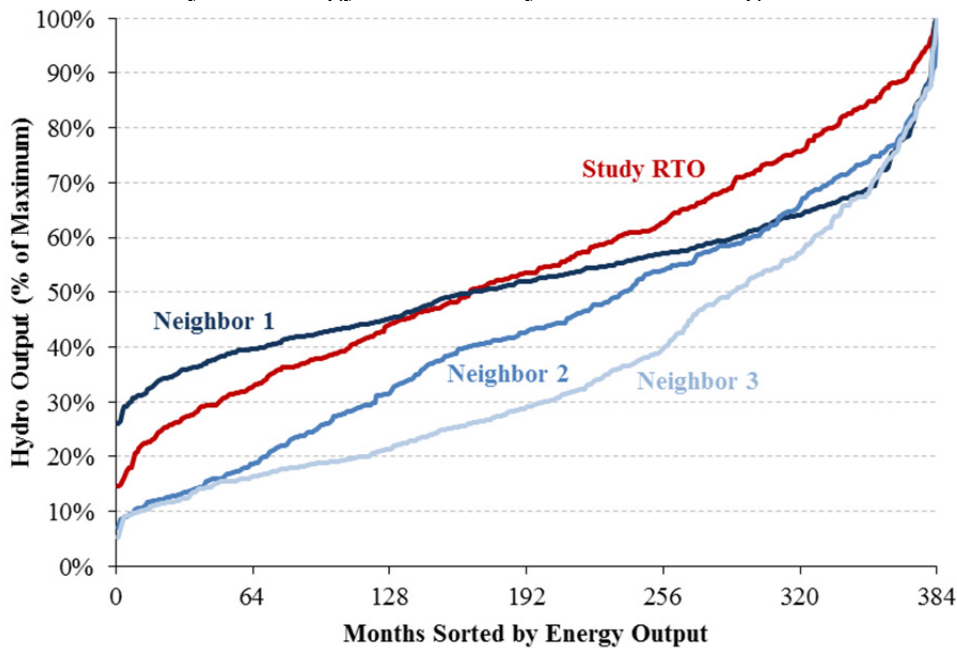
We model the hydro portfolio in each region based on segments treated as non-schedulable run of river, schedulable peak shaving hydro, and dispatchable emergency capacity. The run-of-river segment is dispatched as baseload capacity providing its designated capacity every hour of the year. The schedulable 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 SERVVM 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, SERVVM 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, SERVVM models correspondingly little generation and capacity available during peak conditions. In years with substantial historical generation, SERVVM 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 SERVVM 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. SERVVM 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 SERVVM 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.

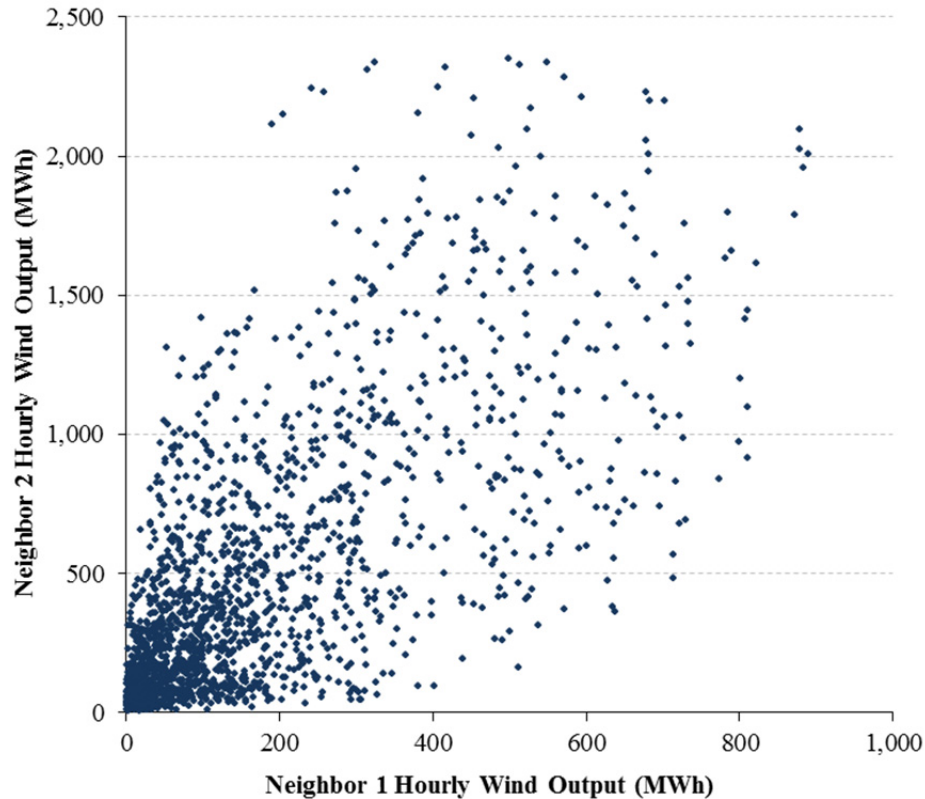
As demonstrated in Figure 48 for Regions 1 and 2 (based on EWITS wind profiles for central MISO and western PJM), there is some correlation in hourly wind output among neighboring regions, but this correlation is small compared to the total volatility in wind output. Consistent with the geography of 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, SERVVM 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 annual 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

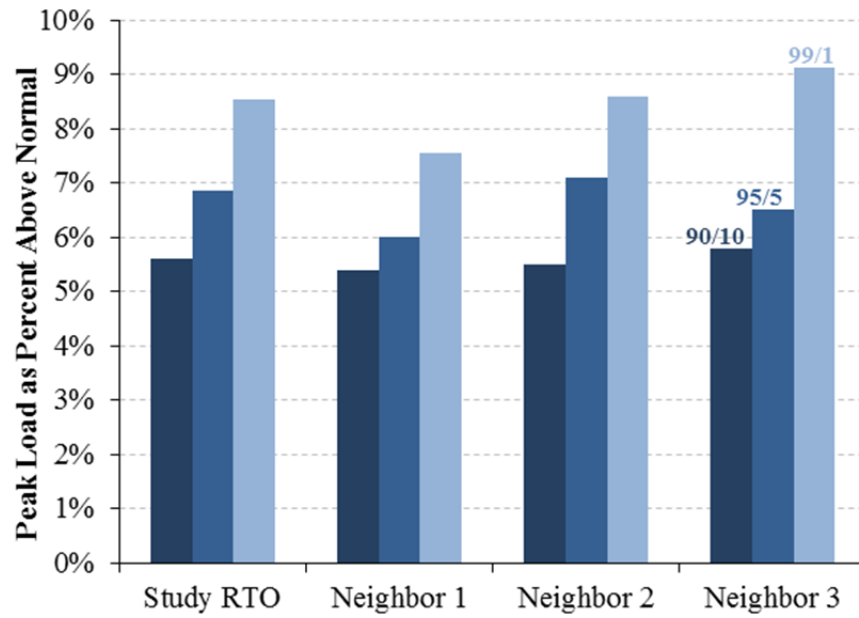


Figure 50
Winter Peak Load in Extreme Years as Percent above Weather-Normal Peak

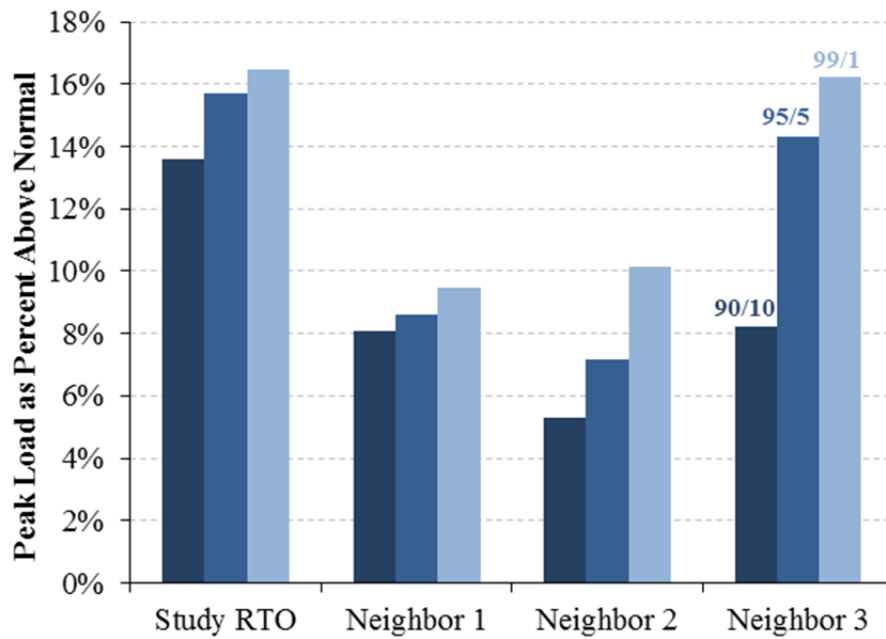
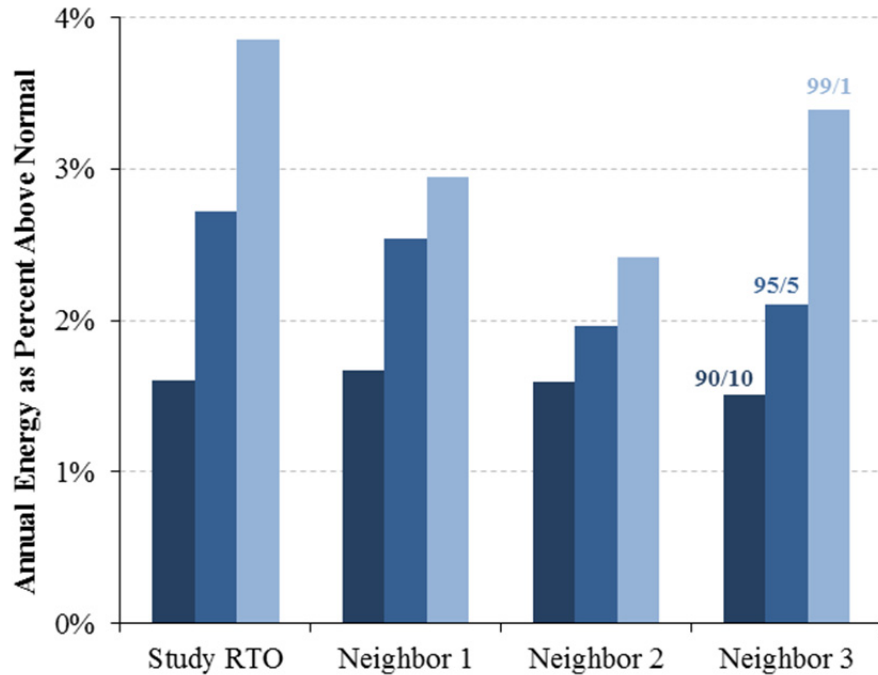
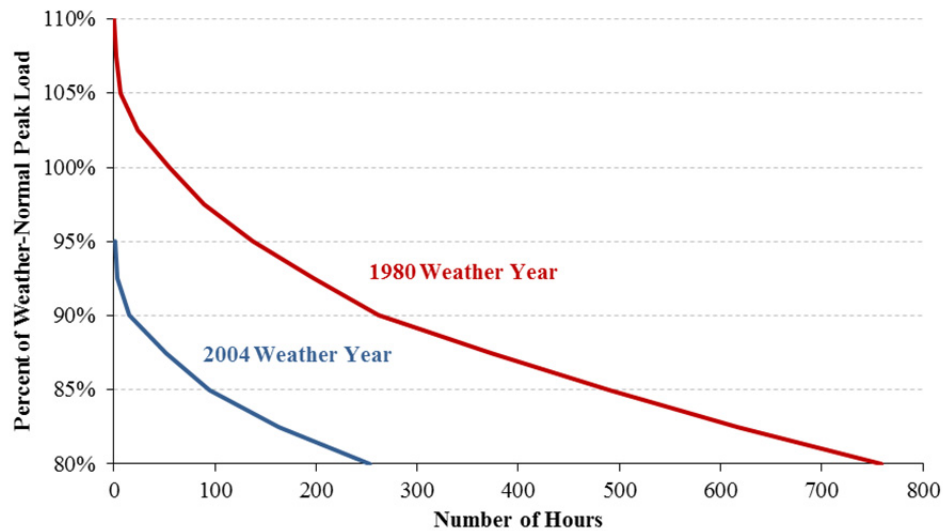


Figure 51
Annual Energy in Extreme Years as Percent above Weather-Normal Year



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	During Multi-Region Coincident Peak	During Study RTO Peak	Relative to Multi-Region Coincident Peak	Relative to Study RTO Peak
	(MW)	(MW)	(MW)	(%)	(%)
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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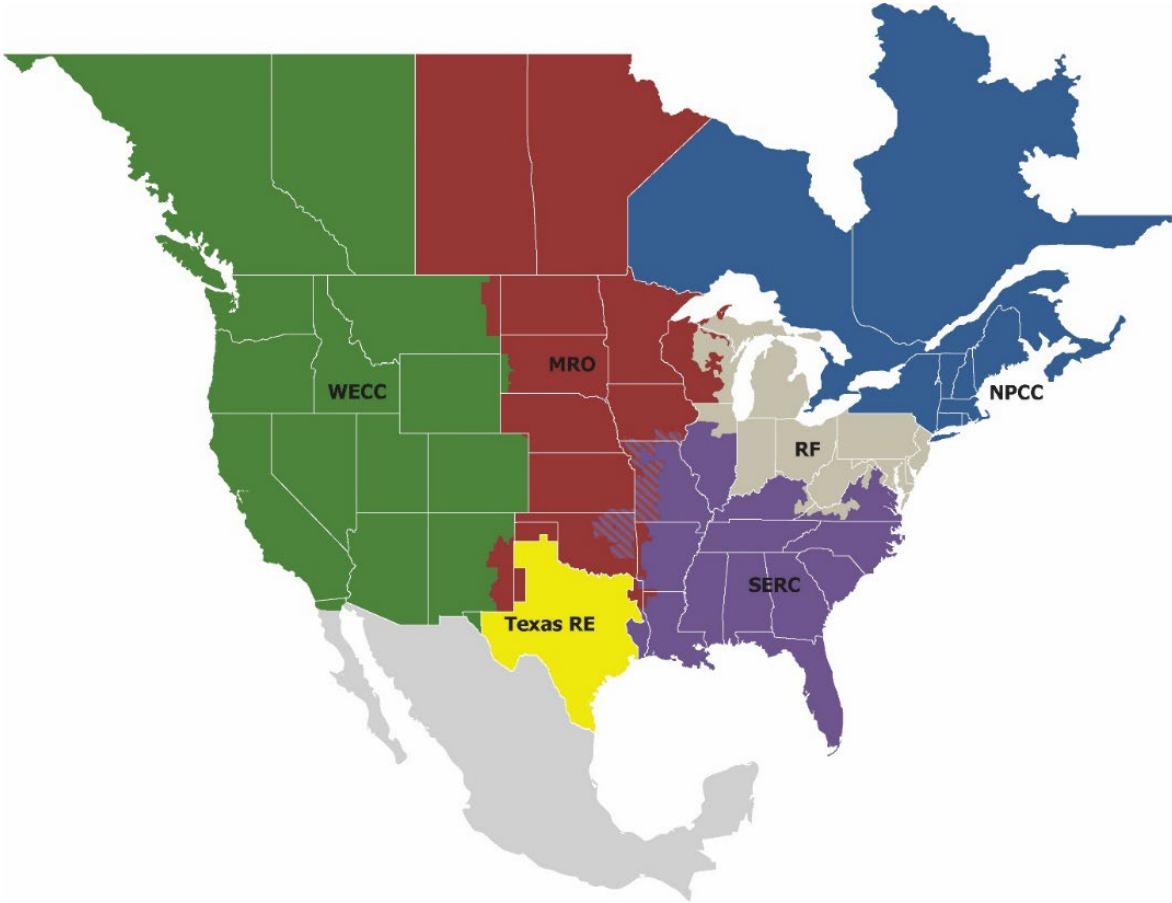
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Preface

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.

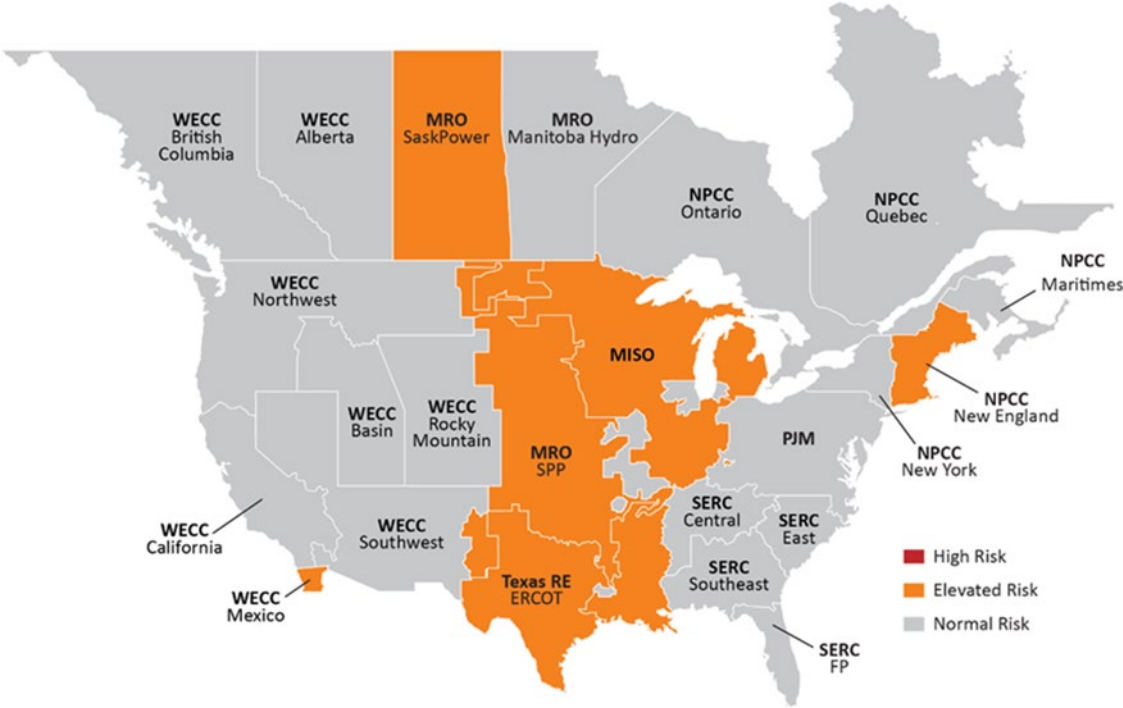


Figure 1: Summer Reliability Risk Area Summary

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.

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.

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.⁹
 - 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.

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.

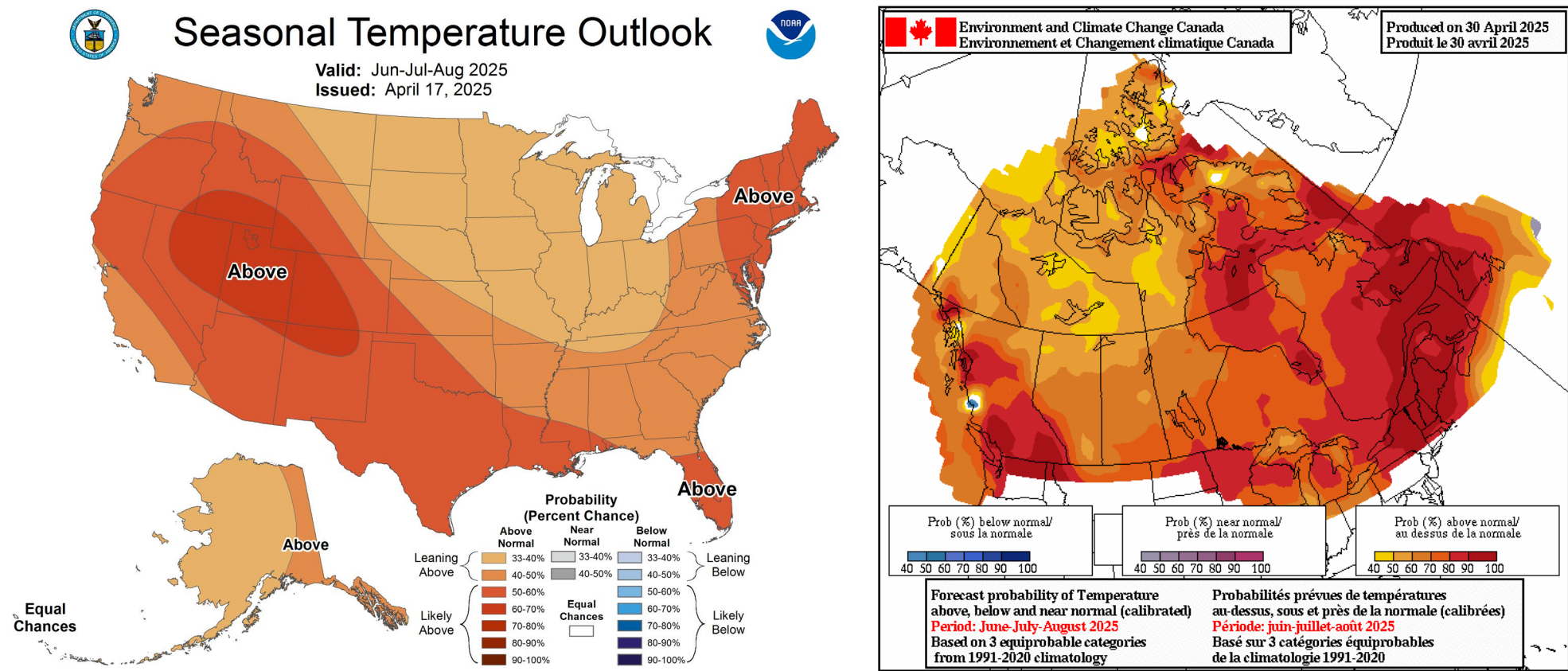


Figure 2: United States and Canada Summer Temperature Outlook¹⁰

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	- 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 scenarios²
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- 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
Potential for insufficient operating reserves in above-normal conditions	
Normal	- 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 scenarios⁴
Sufficient operating reserves expected	
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

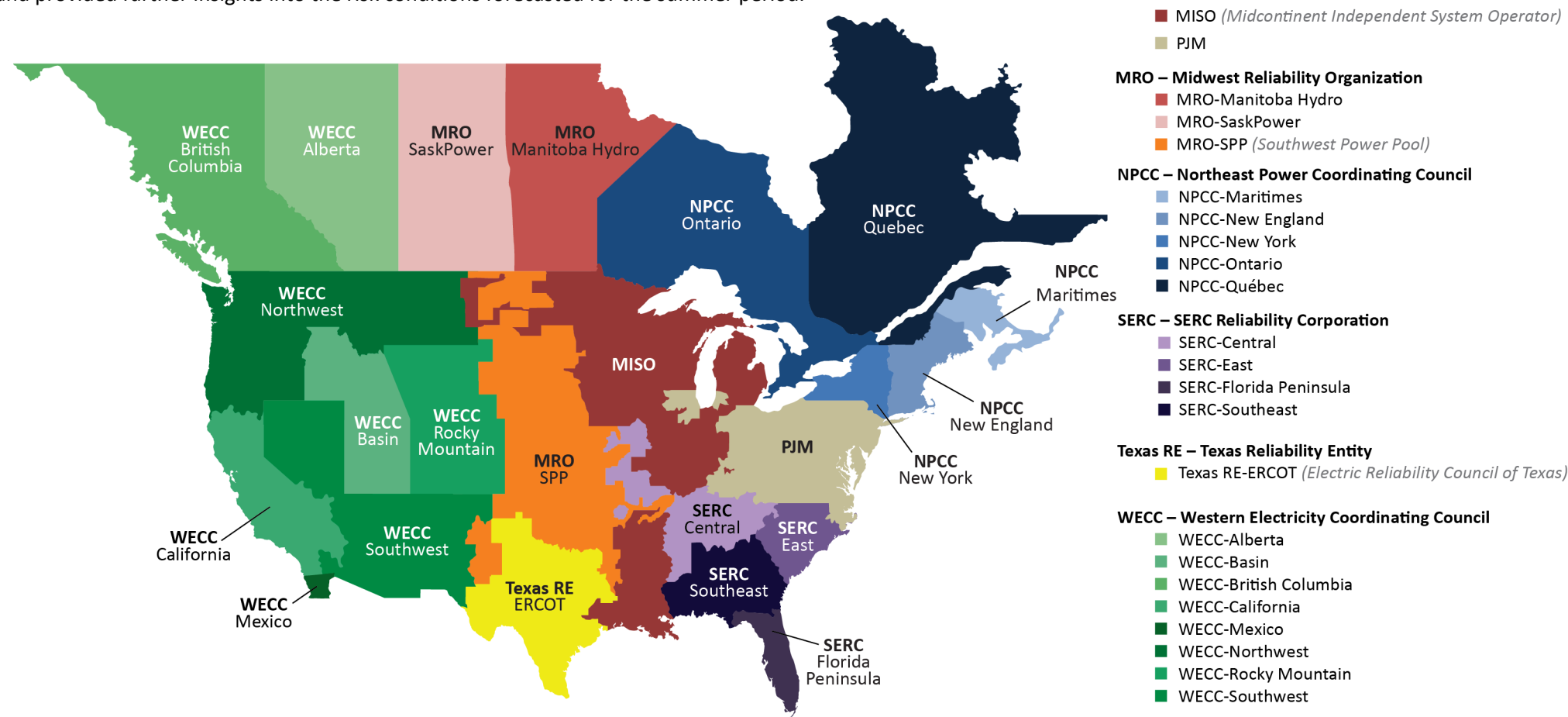
Assessment Area	Type of Assessment	Results and Insight from Assessment
NPCC-Ontario		NPCC’s preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative 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.

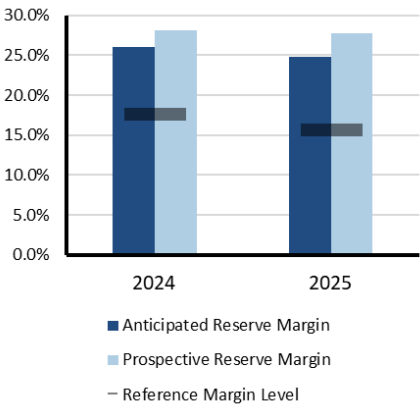
Highlights

- 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.

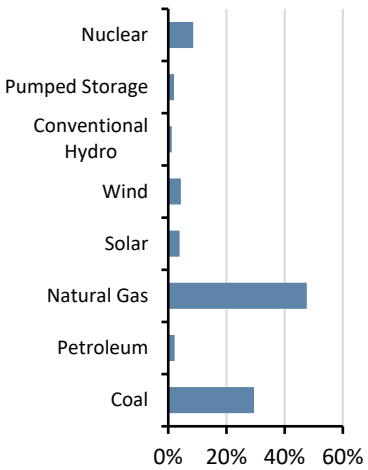
Risk Scenario Summary

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.

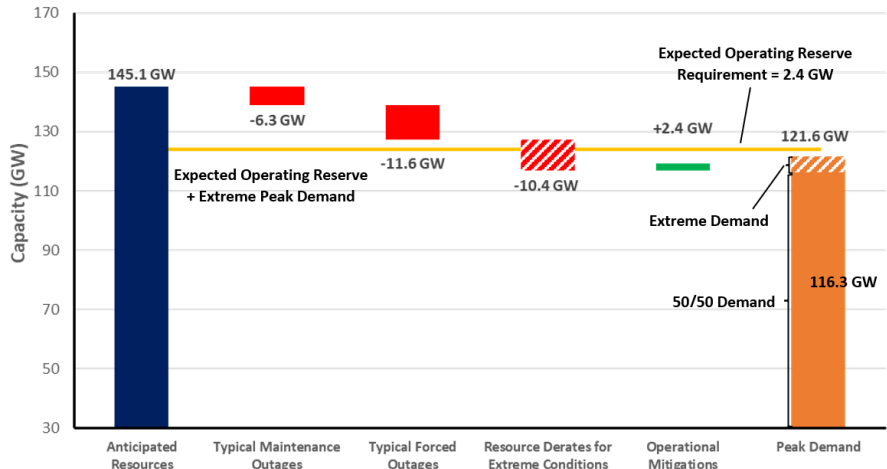
On-Peak Reserve Margin



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.

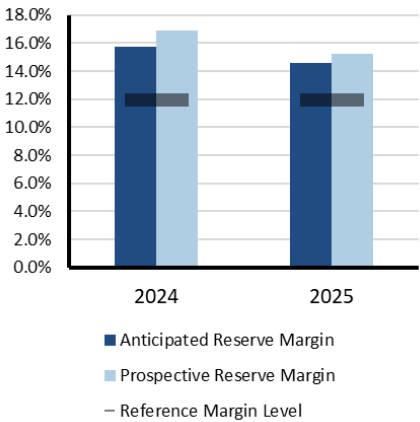
Highlights

- 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.

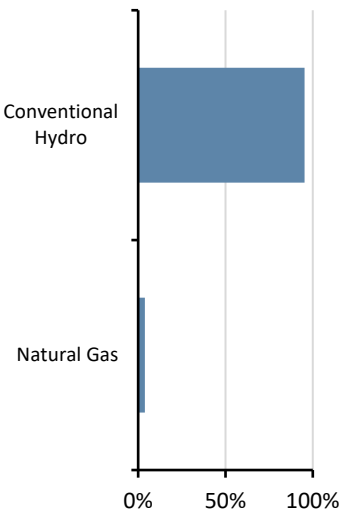
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

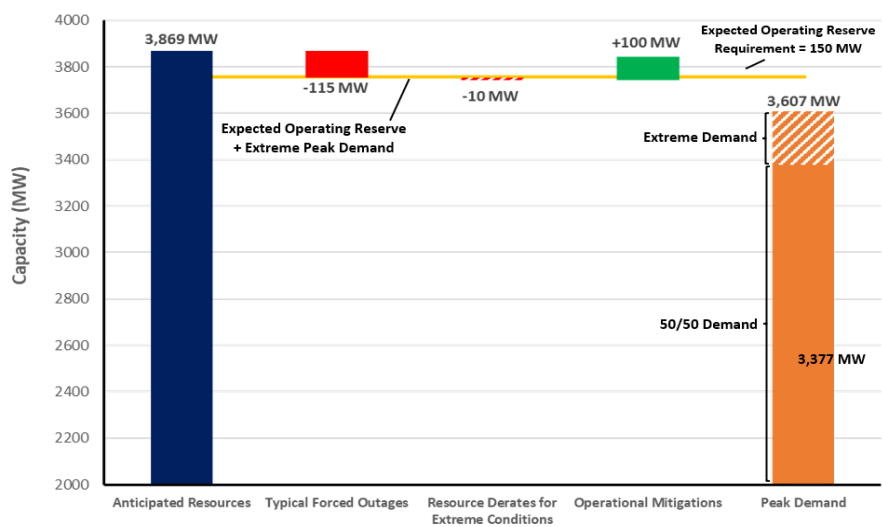
On-Peak Reserve Margin



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

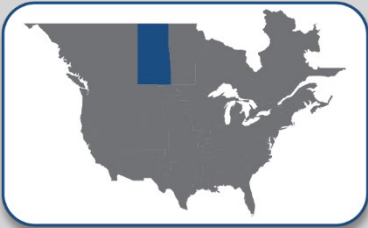
Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

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.

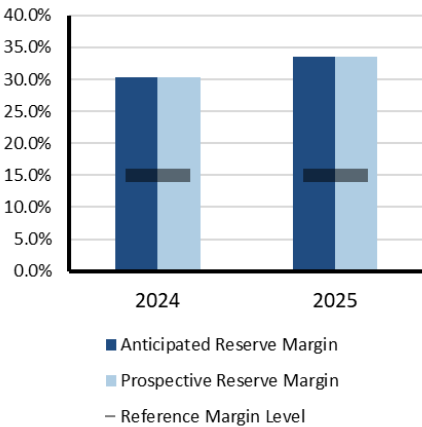
Highlights

- 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.

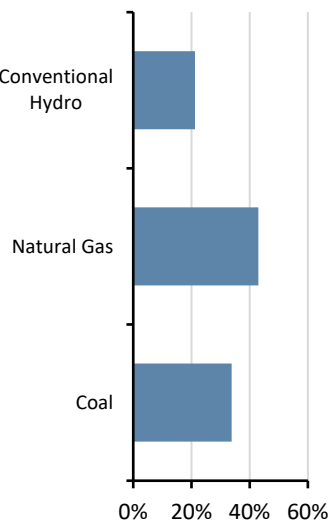
Risk Scenario Summary

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.

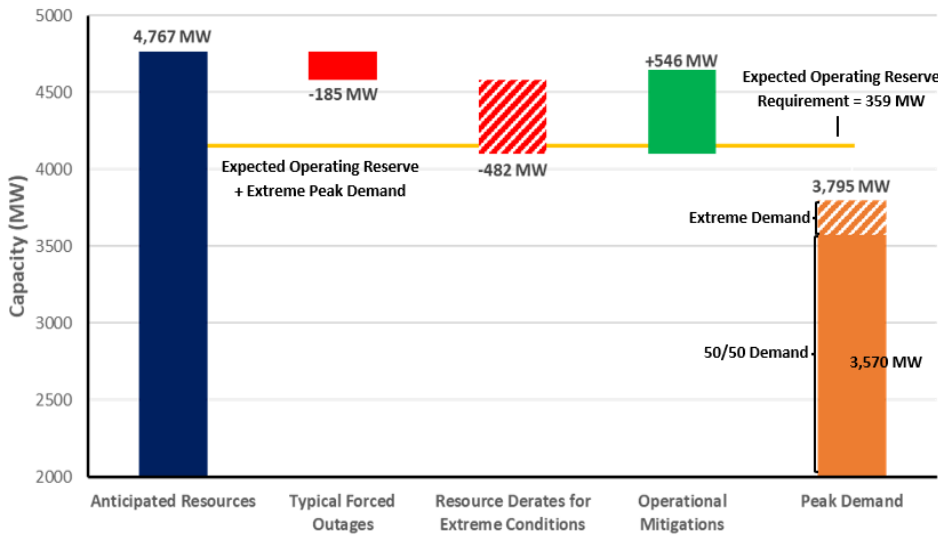
On-Peak Reserve Margin



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 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.

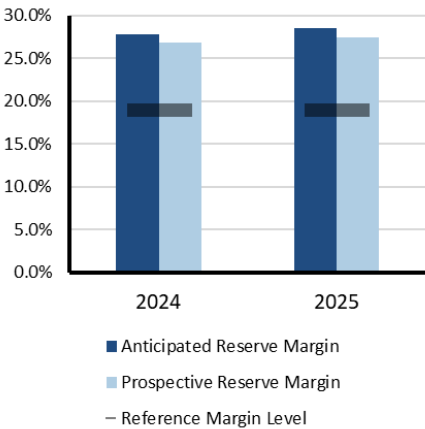
Highlights

- 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.

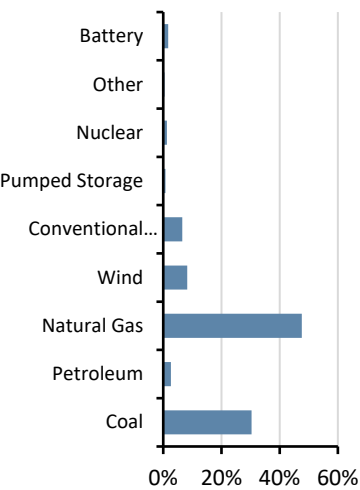
Risk Scenario Summary

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.

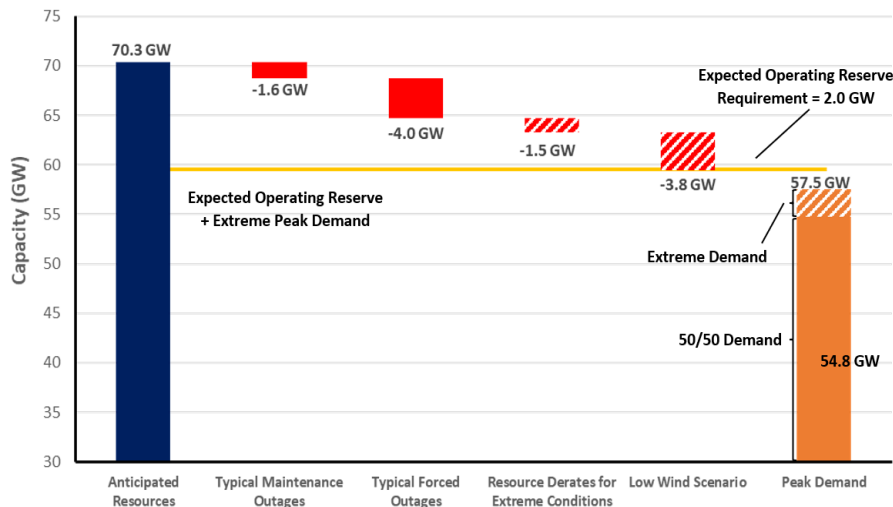
On-Peak Reserve Margin



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.

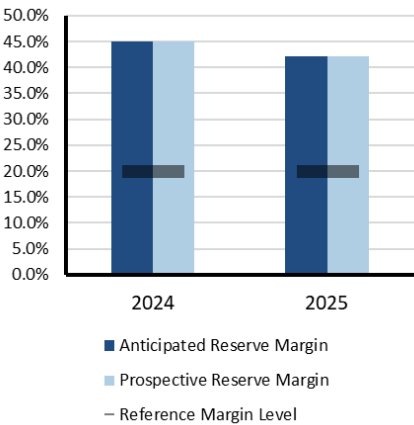
Highlights

- 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.

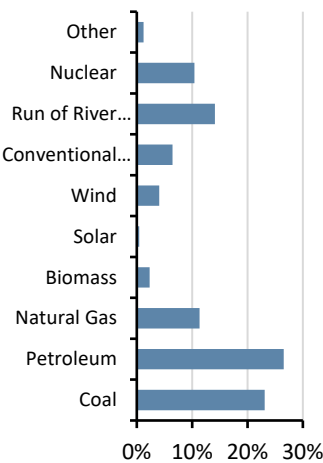
Risk Scenario Summary

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.

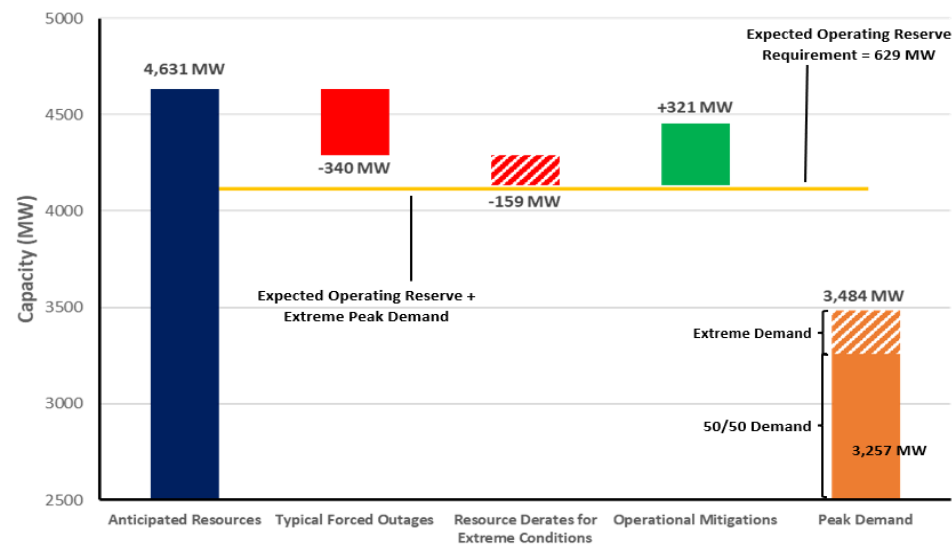
On-Peak Reserve Margin



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 (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.

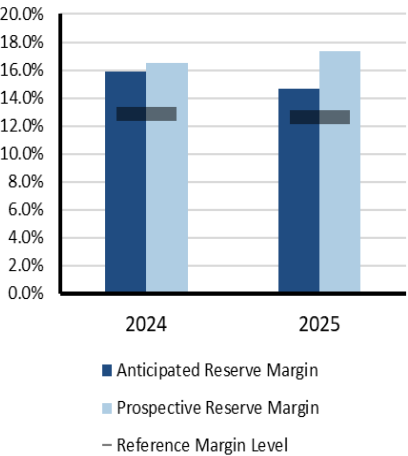
Highlights

- 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](#).

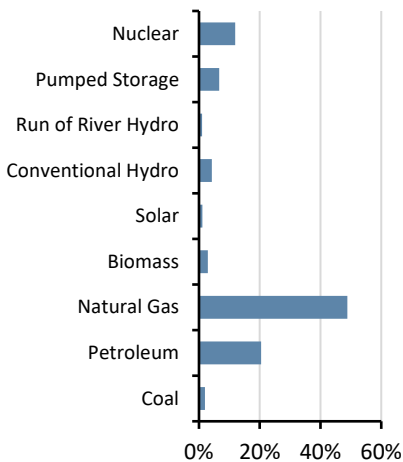
Risk Scenario Summary

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.

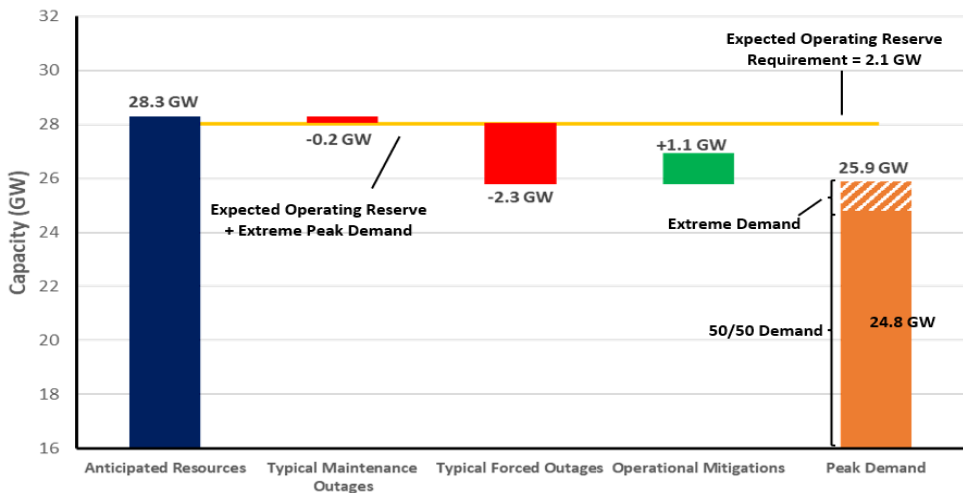
On-Peak Reserve Margin



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: 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%.

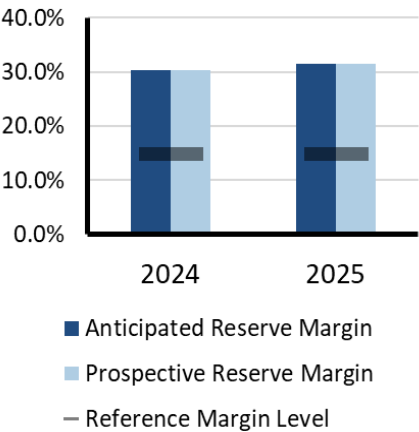
Highlights

- 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](#).

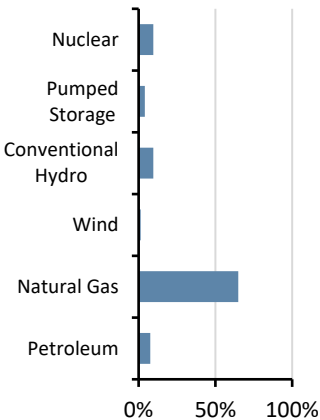
Risk Scenario Summary

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.

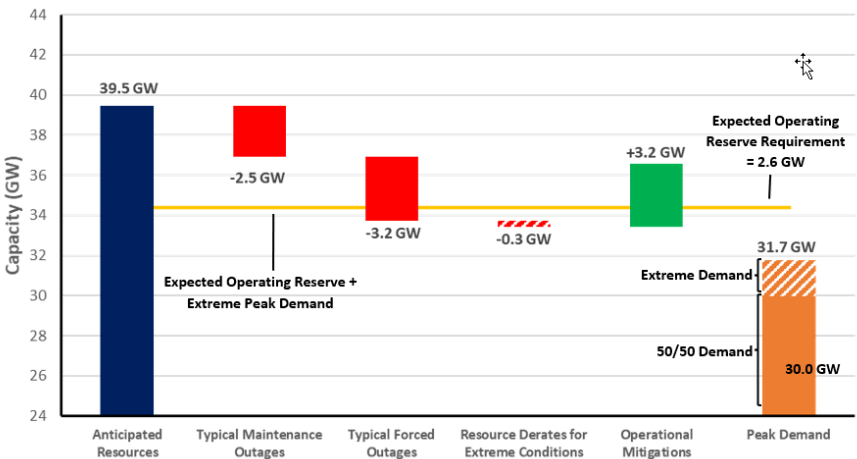
On-Peak Reserve Margin



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) 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.

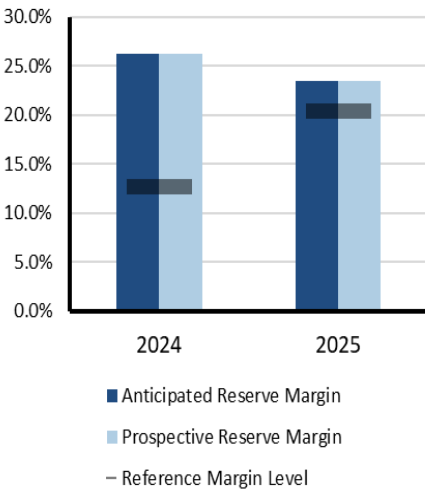
Highlights

- 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."

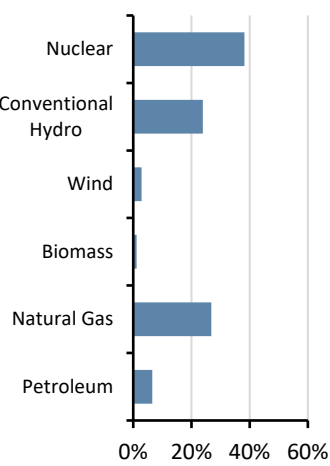
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

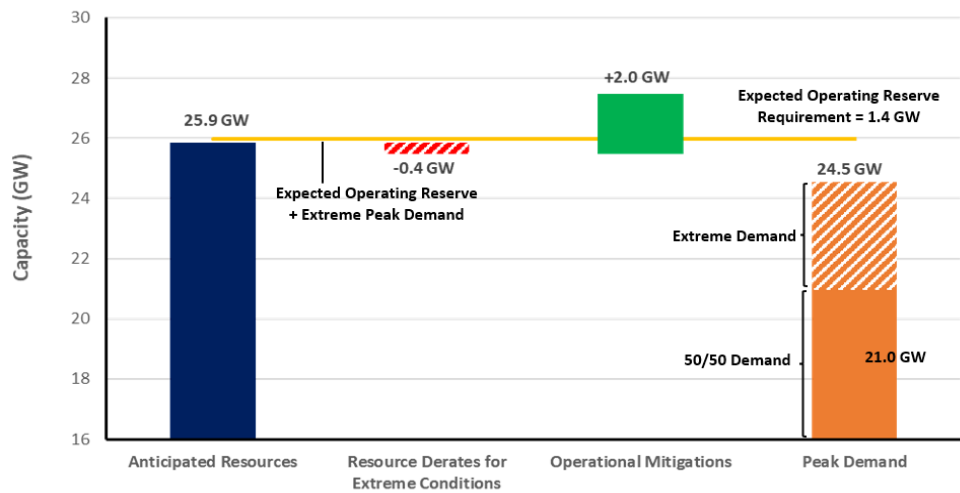
On-Peak Reserve Margin



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.

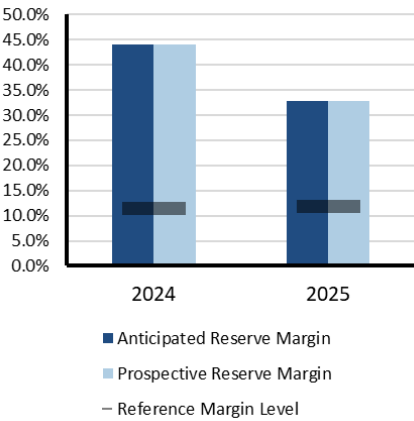
Highlights

- 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.

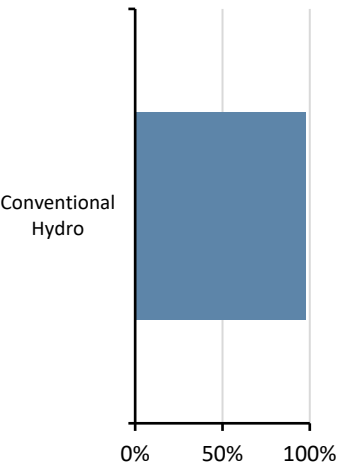
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

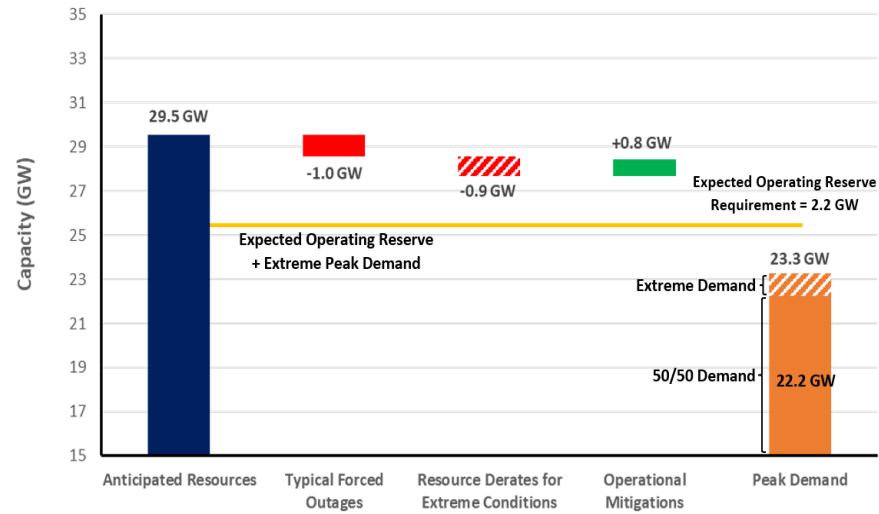
On-Peak Reserve Margin



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.



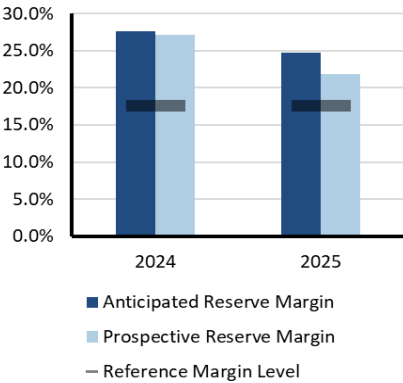
PJM

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.

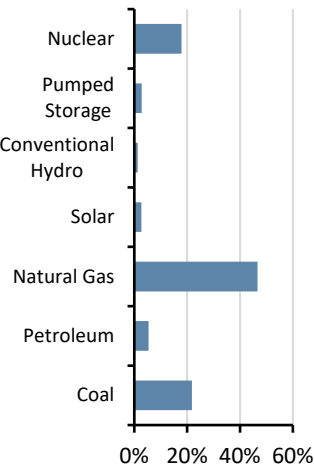
On-Peak Reserve Margin



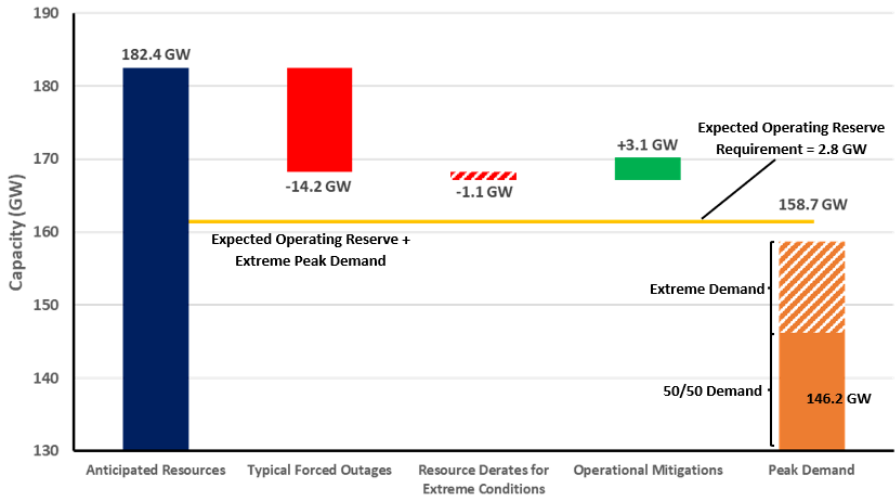
Risk Scenario Summary

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 (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



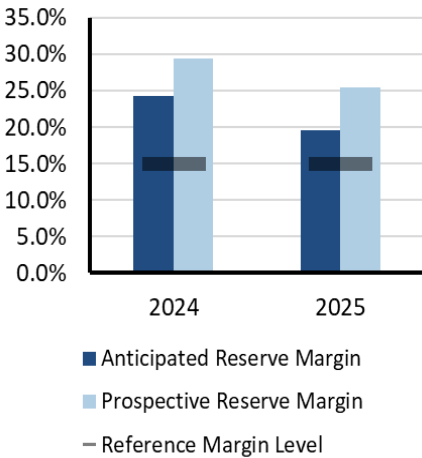
SERC-Central

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.

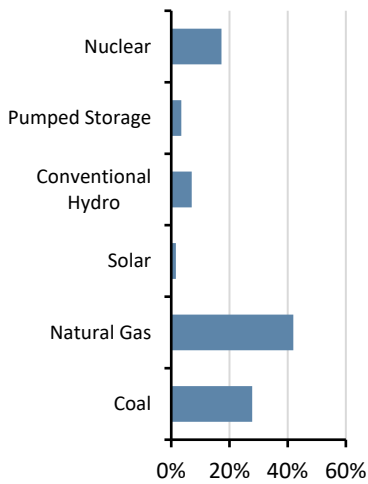
On-Peak Reserve Margin



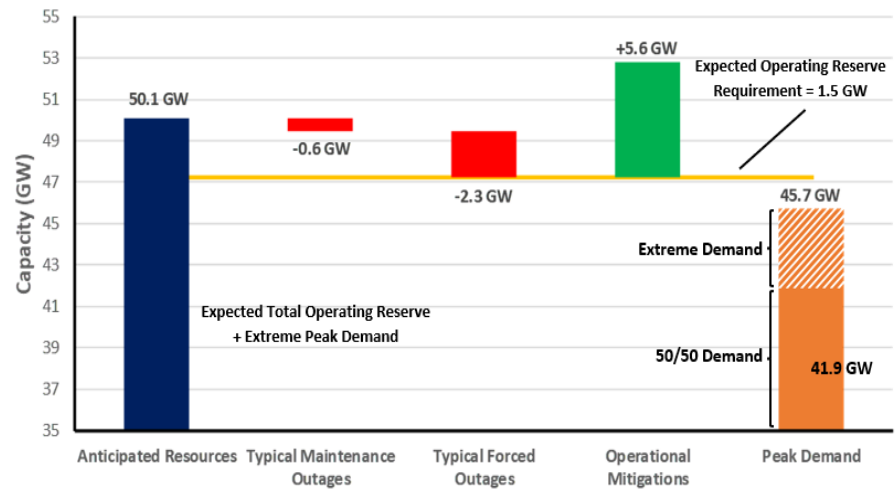
Risk Scenario Summary

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.

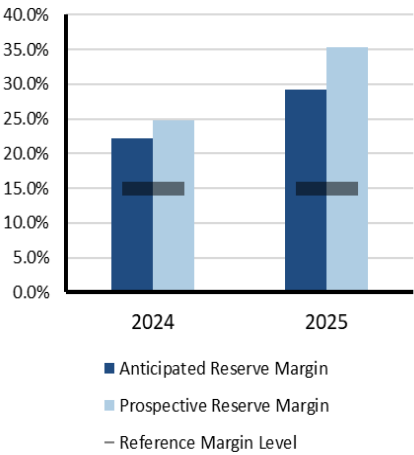
Highlights

- 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.

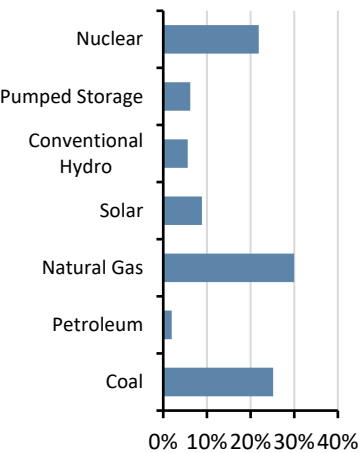
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

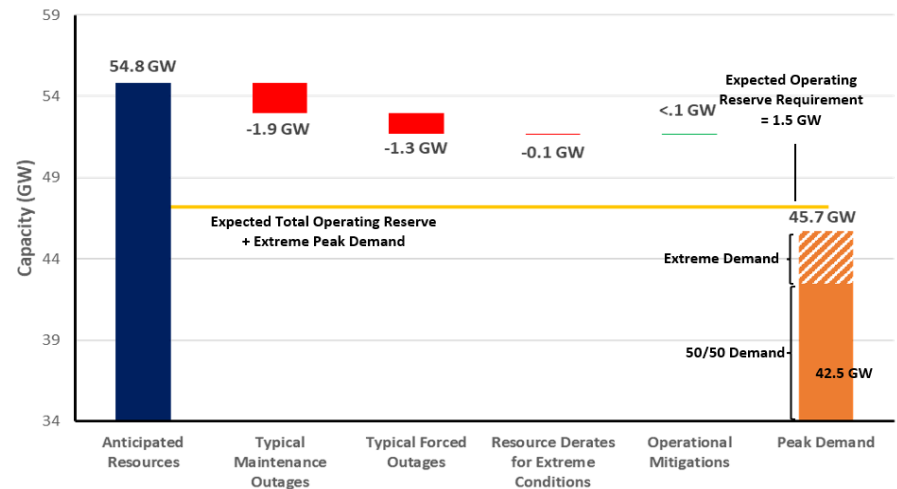
On-Peak Reserve Margin



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 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



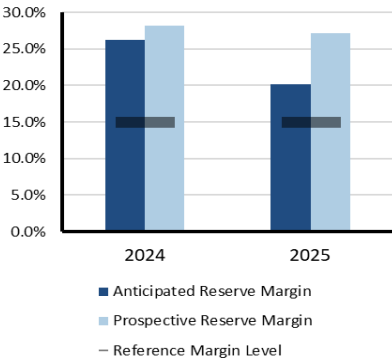
SERC-Florida Peninsula

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.

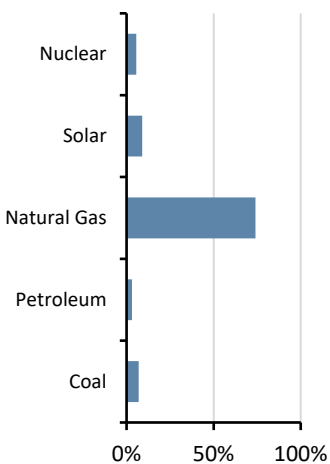
On-Peak Reserve Margin



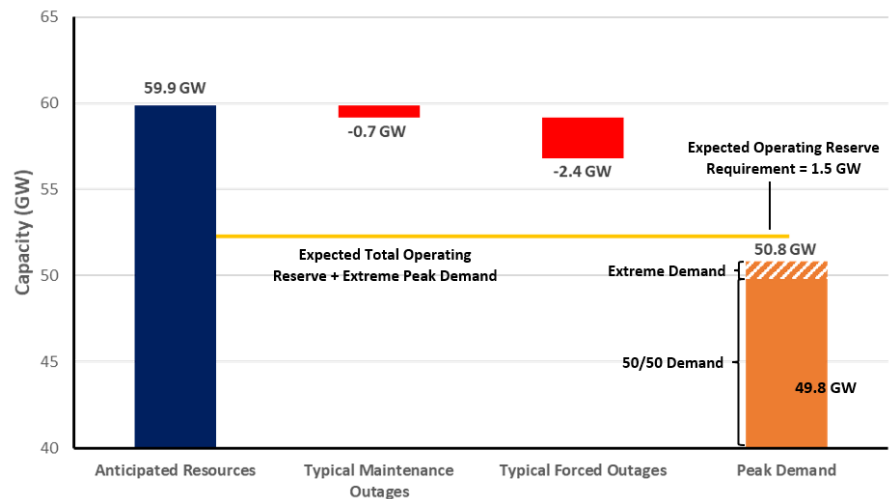
Risk Scenario Summary

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.

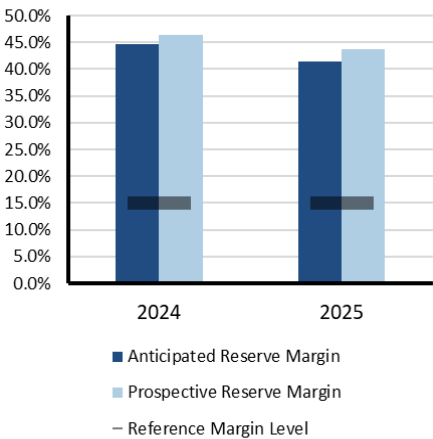
Highlights

- 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.

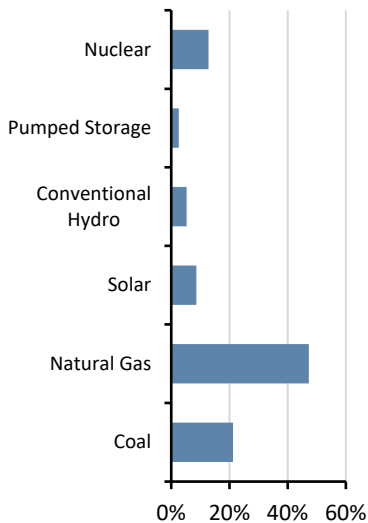
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

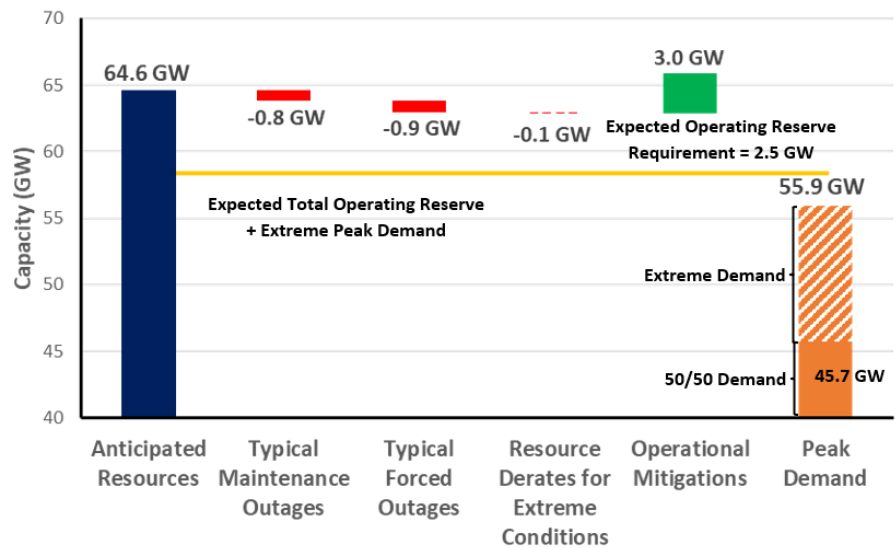
On-Peak Reserve Margin



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

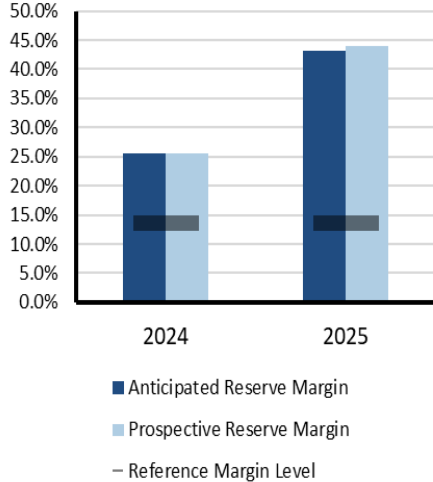
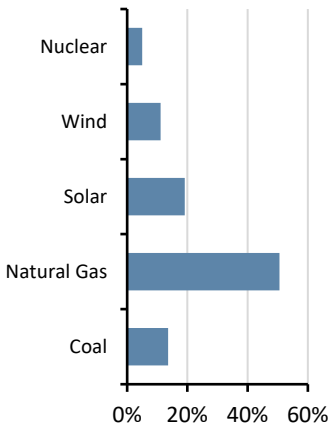
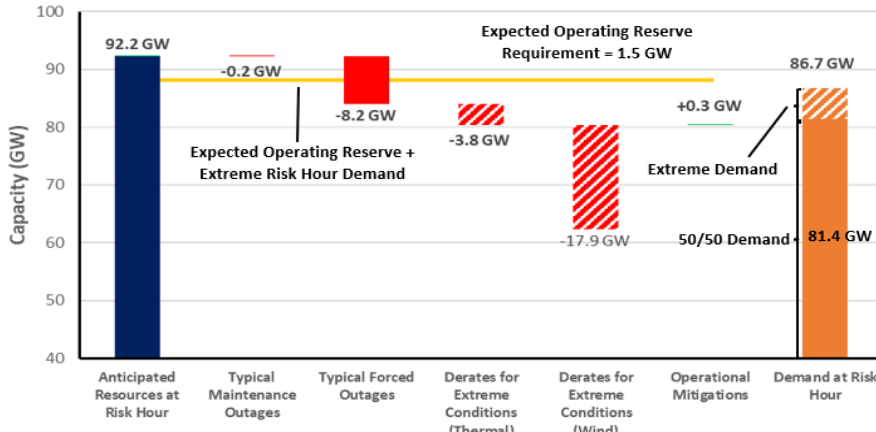
Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

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.	On-Peak Reserve Margin  <table><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2024</td><td>~25.0%</td><td>~25.0%</td><td>15.0%</td></tr><tr><td>2025</td><td>~43.0%</td><td>~44.0%</td><td>15.0%</td></tr></table>	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2024	~25.0%	~25.0%	15.0%	2025	~43.0%	~44.0%	15.0%																				
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2025	~43.0%	~44.0%	15.0%																														
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 Fuel Mix  <table><tr><th>Fuel Source</th><th>Percentage</th></tr><tr><td>Nuclear</td><td>~5%</td></tr><tr><td>Wind</td><td>~12%</td></tr><tr><td>Solar</td><td>~18%</td></tr><tr><td>Natural Gas</td><td>~48%</td></tr><tr><td>Coal</td><td>~15%</td></tr></table>	Fuel Source	Percentage	Nuclear	~5%	Wind	~12%	Solar	~18%	Natural Gas	~48%	Coal	~15%	2025 Summer Risk Period Scenario (9:00 p.m. local time)  <table><tr><th>Category</th><th>Value (GW)</th></tr><tr><td>Anticipated Resources at Risk Hour</td><td>92.2</td></tr><tr><td>Typical Maintenance Outages</td><td>-0.2</td></tr><tr><td>Typical Forced Outages</td><td>-8.2</td></tr><tr><td>Derates for Extreme Conditions (Thermal)</td><td>-3.8</td></tr><tr><td>Derates for Extreme Conditions (Wind)</td><td>-17.9</td></tr><tr><td>50/50 Demand</td><td>81.4</td></tr><tr><td>Operational Mitigations</td><td>+0.3</td></tr><tr><td>Demand at Risk Hour</td><td>86.7</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>88.2</td></tr></table> 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	Category	Value (GW)	Anticipated Resources at Risk Hour	92.2	Typical Maintenance Outages	-0.2	Typical Forced Outages	-8.2	Derates for Extreme Conditions (Thermal)	-3.8	Derates for Extreme Conditions (Wind)	-17.9	50/50 Demand	81.4	Operational Mitigations	+0.3	Demand at Risk Hour	86.7	Expected Operating Reserve Requirement	88.2
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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.

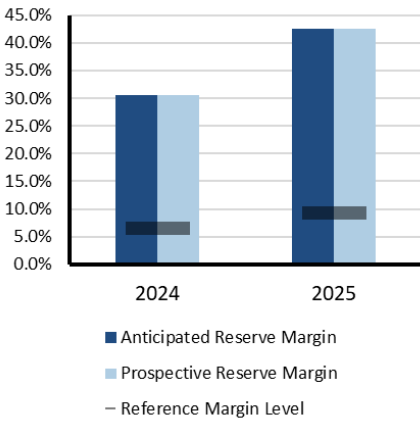
Highlights

- 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.

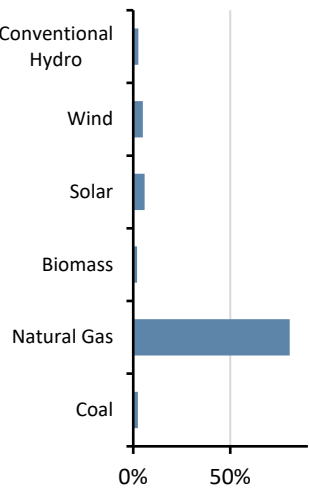
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

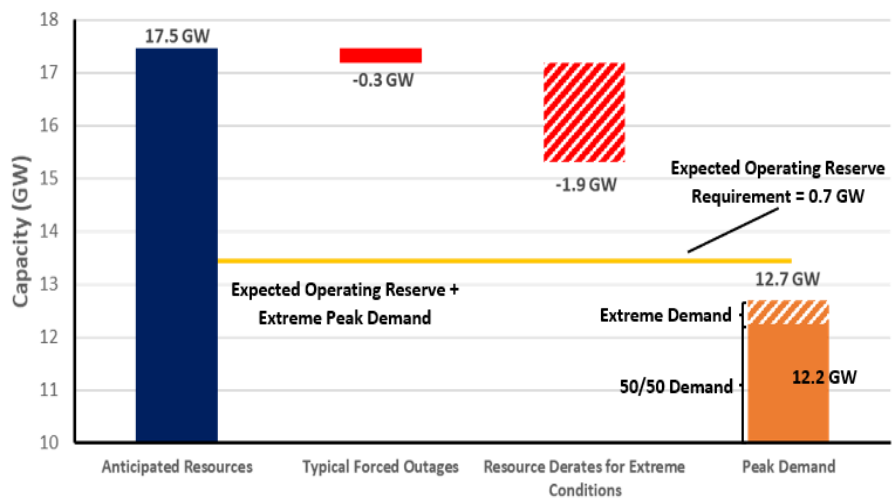
On-Peak Reserve Margin



On-Peak Fuel Mix

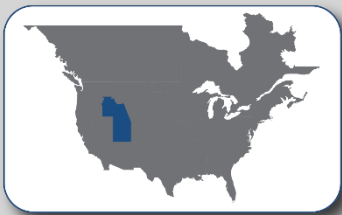


2025 Summer Risk Period Scenario



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

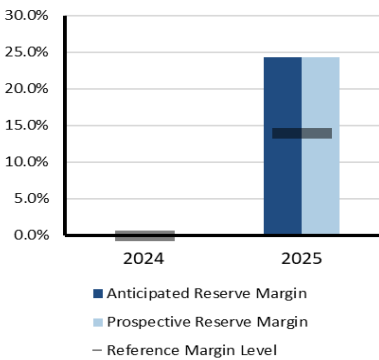
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During 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

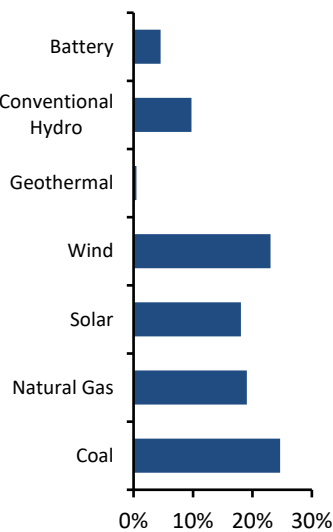
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

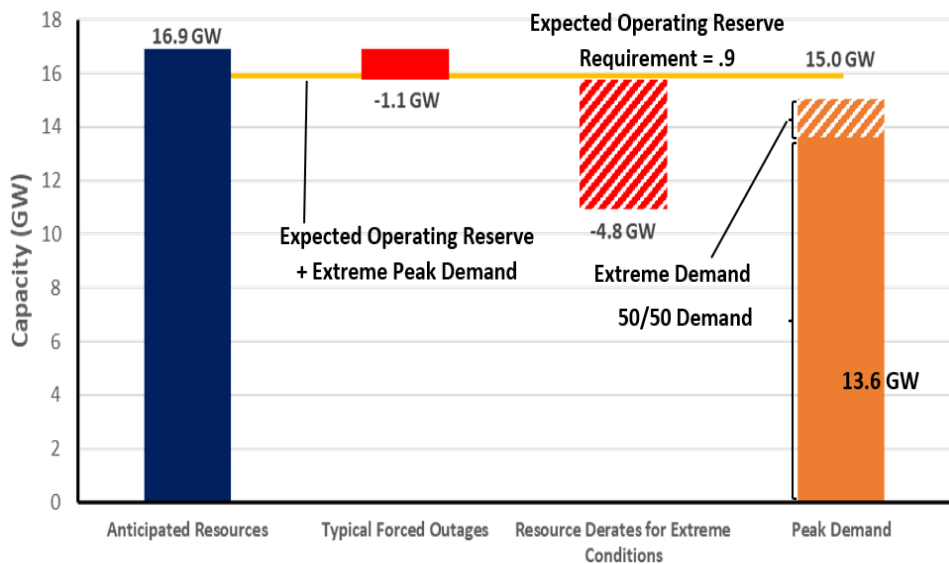
(Note: year comparison not available)



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.

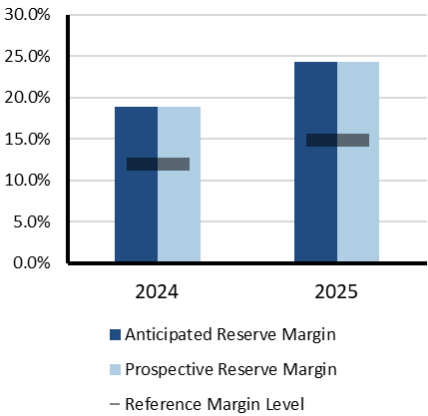
Highlights

- 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.

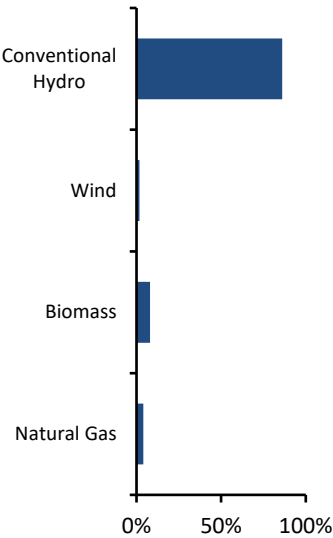
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

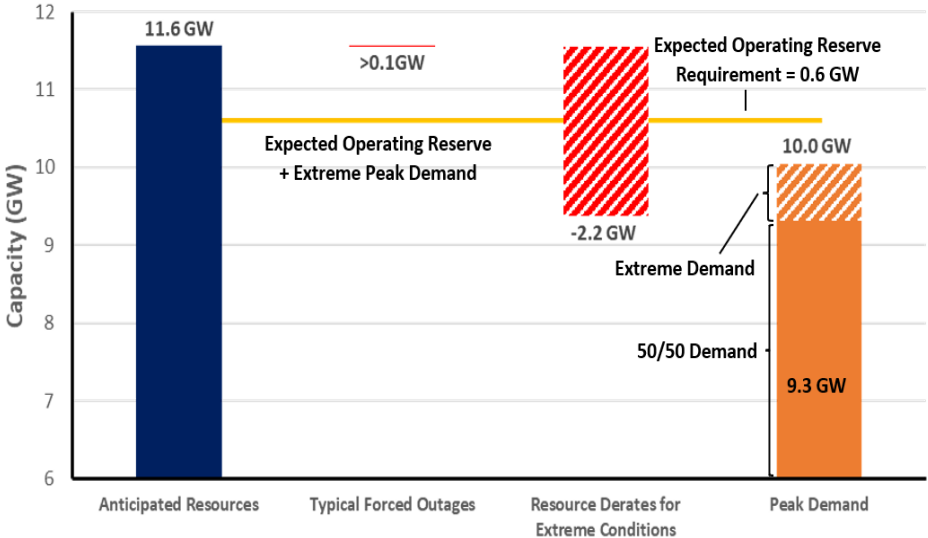
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



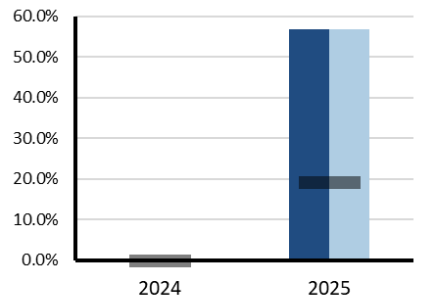
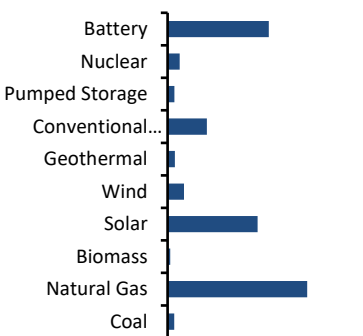
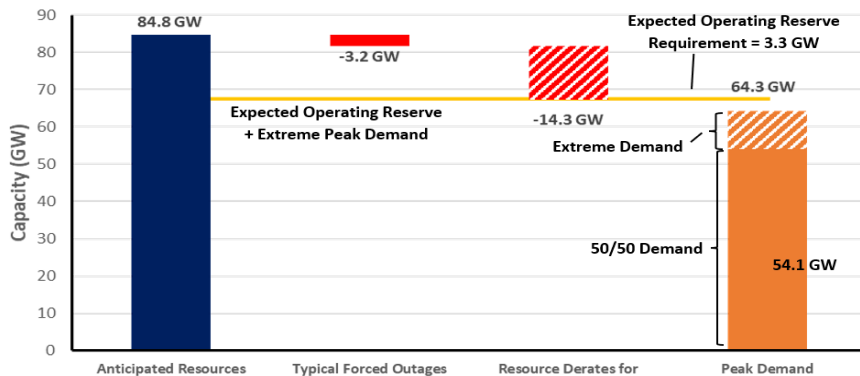
Scenario Description (See Data Concepts and Assumptions)

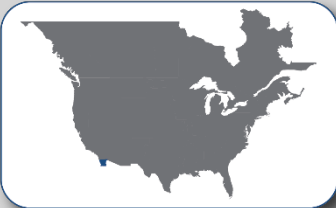
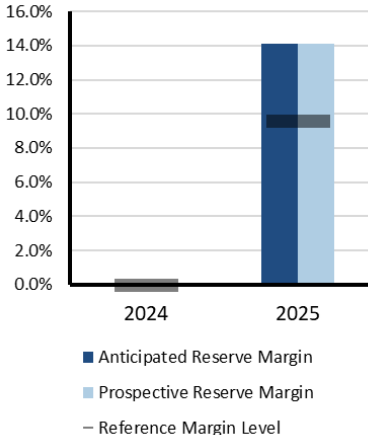
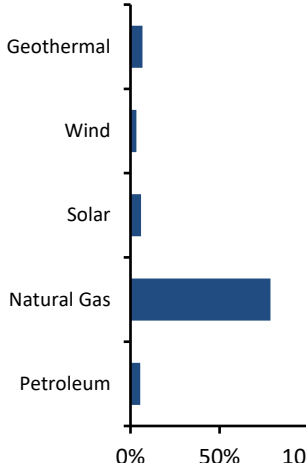
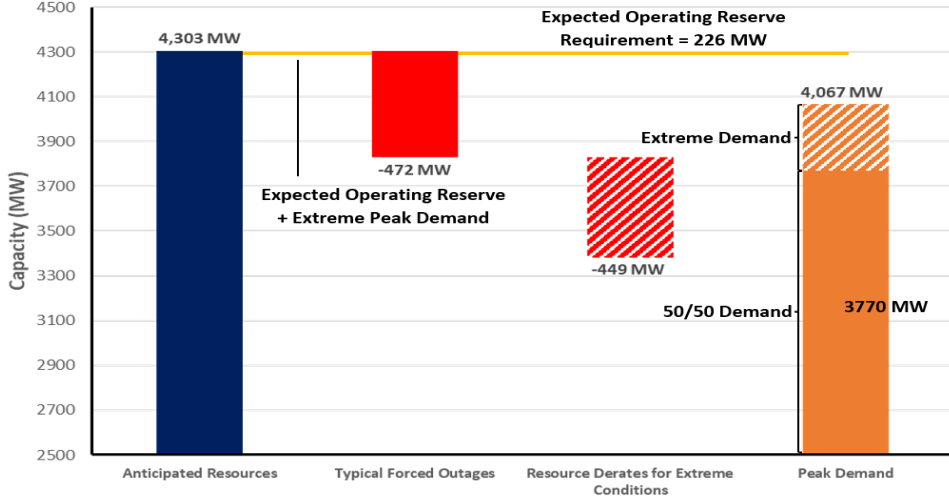
Risk Period: Highest risk for unserved energy at peak demand hour

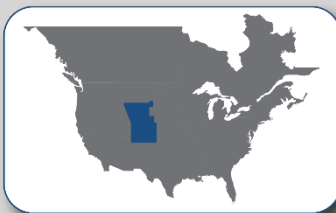
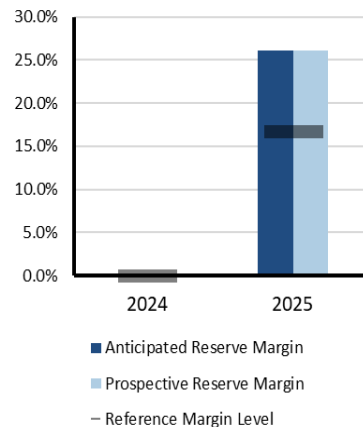
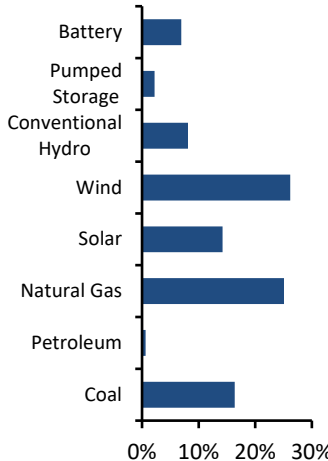
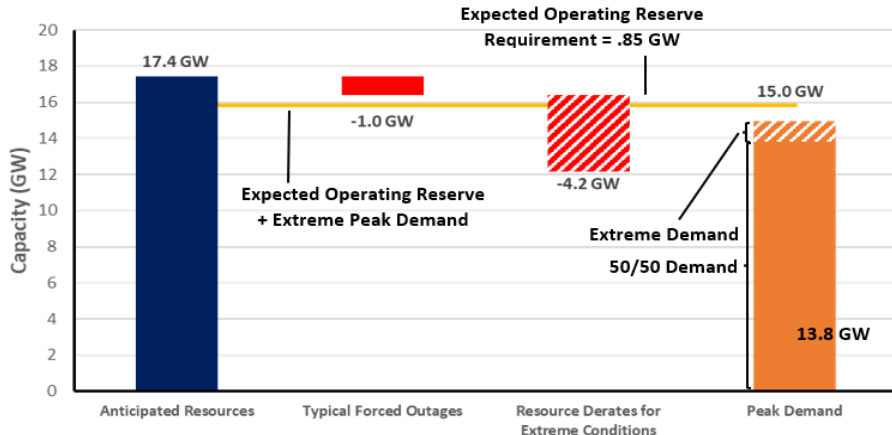
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

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. <i>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.</i>												
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.		On-Peak Reserve Margin (Note: year comparison not available)  <table><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2024</td><td>~0.5%</td><td>~0.5%</td><td>~18.0%</td></tr><tr><td>2025</td><td>~58.0%</td><td>~58.0%</td><td>~18.0%</td></tr></table>	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2024	~0.5%	~0.5%	~18.0%	2025	~58.0%	~58.0%	~18.0%
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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 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. <i>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.</i>																																
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.		On-Peak Reserve Margin (Note: year comparison not available)  <table border="1"><thead><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr></thead><tbody><tr><td>2024</td><td>~0.5%</td><td>-</td><td>~10.0%</td></tr><tr><td>2025</td><td>~14.1%</td><td>~14.5%</td><td>~10.0%</td></tr></tbody></table>		Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2024	~0.5%	-	~10.0%	2025	~14.1%	~14.5%	~10.0%																		
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	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. <i>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.</i>																																			
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.	On-Peak Reserve Margin  <table><thead><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr></thead><tbody><tr><td>2024</td><td>~1%</td><td>-</td><td>17%</td></tr><tr><td>2025</td><td>~26%</td><td>~26%</td><td>17%</td></tr></tbody></table> (Note: year comparison not available)	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2024	~1%	-	17%	2025	~26%	~26%	17%																							
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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

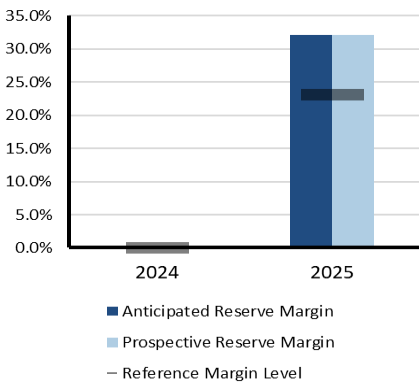
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under 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

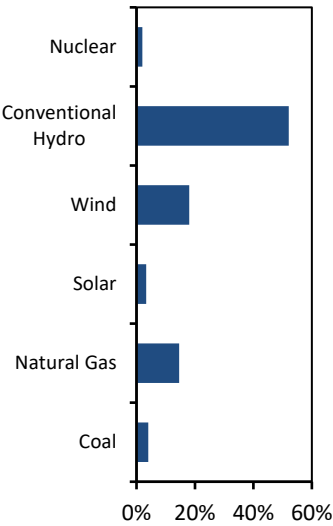
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

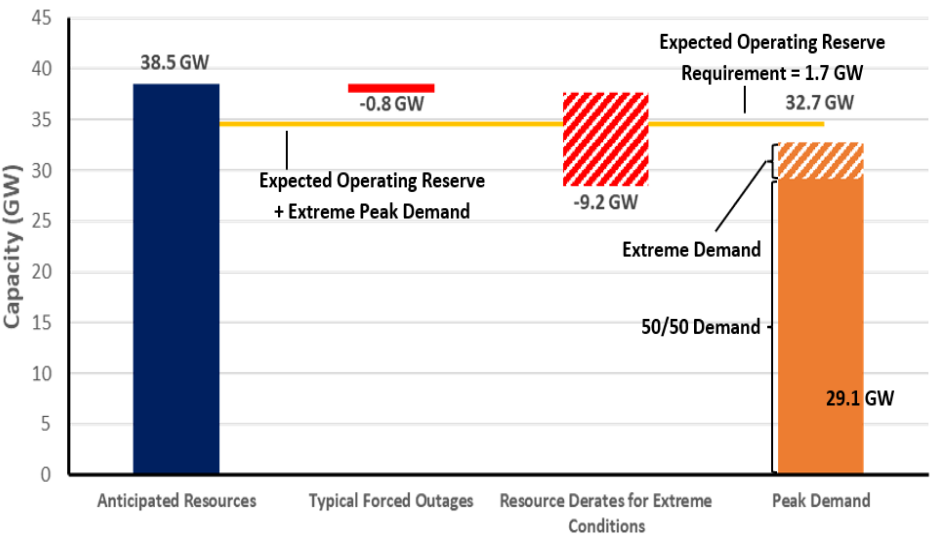
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



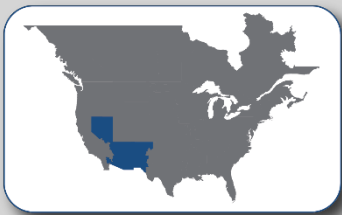
Scenario Description (See Data Concepts and Assumptions)

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

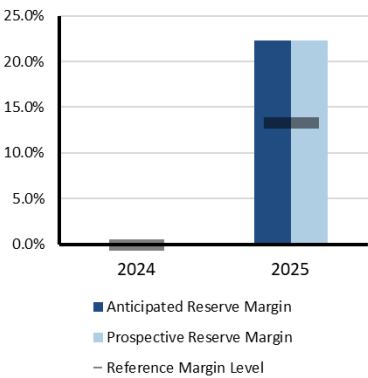
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC’s probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected 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

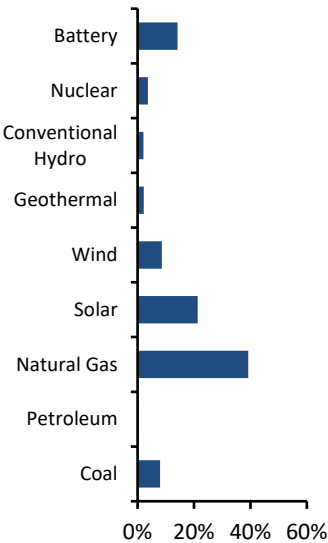
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

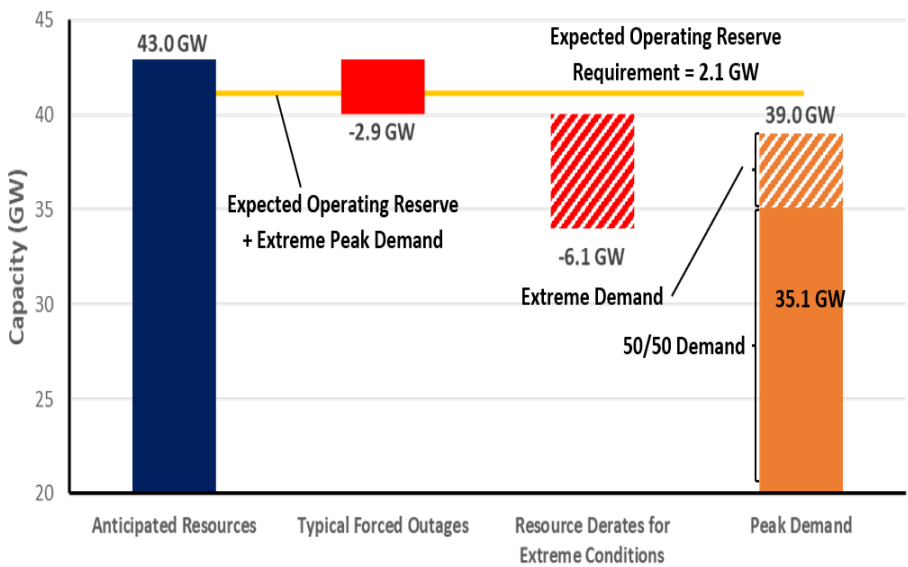
(Note: year comparison not available)



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 load¹² 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 coincident¹⁵ 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](#).

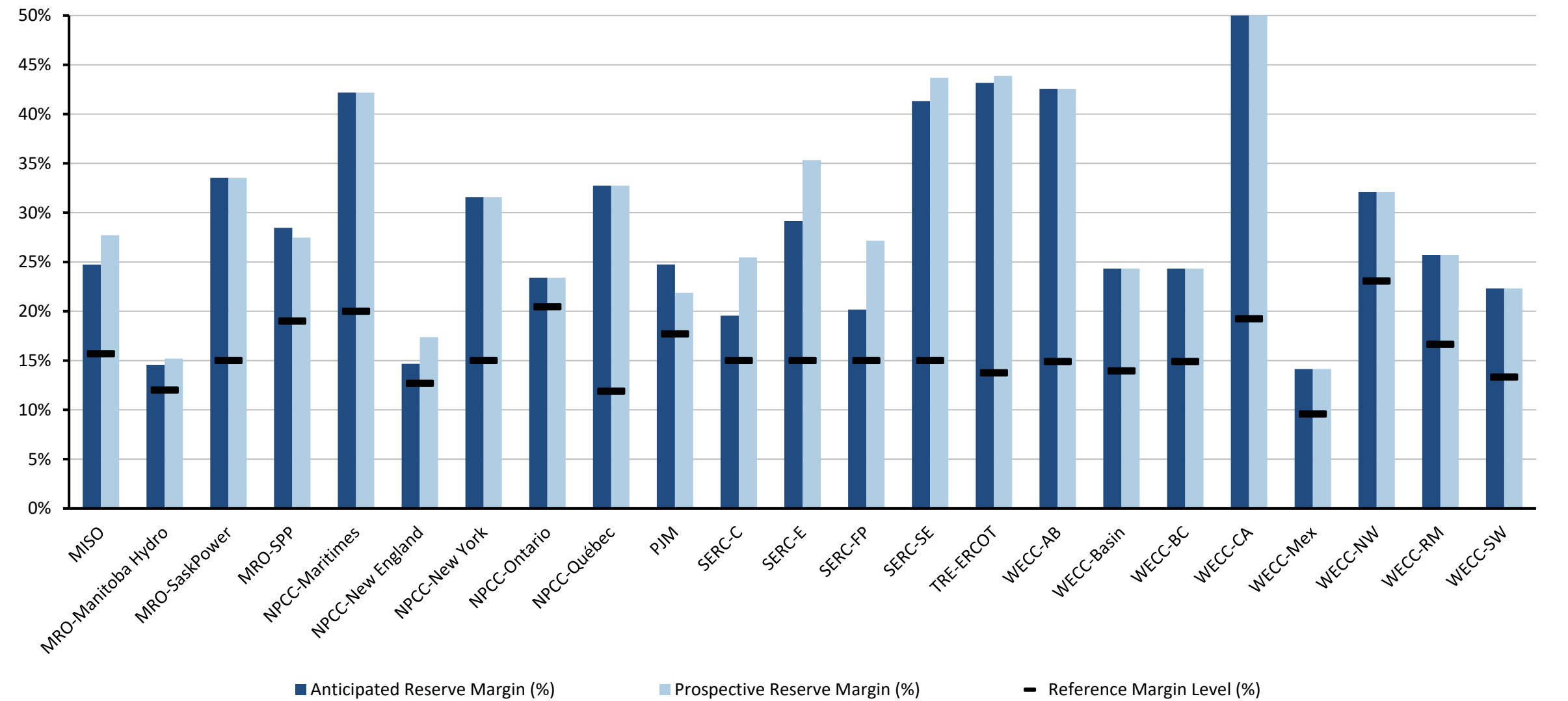


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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.

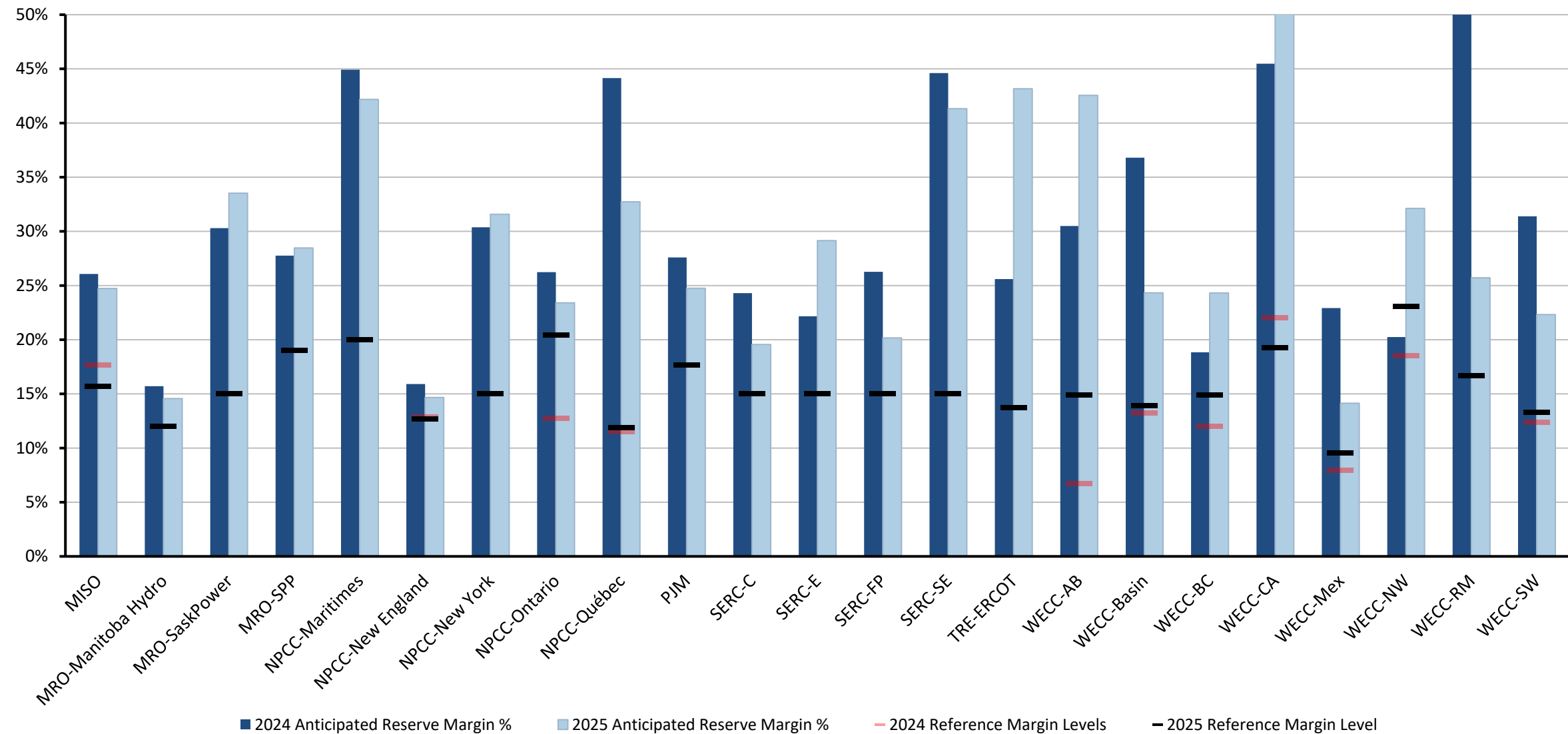


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

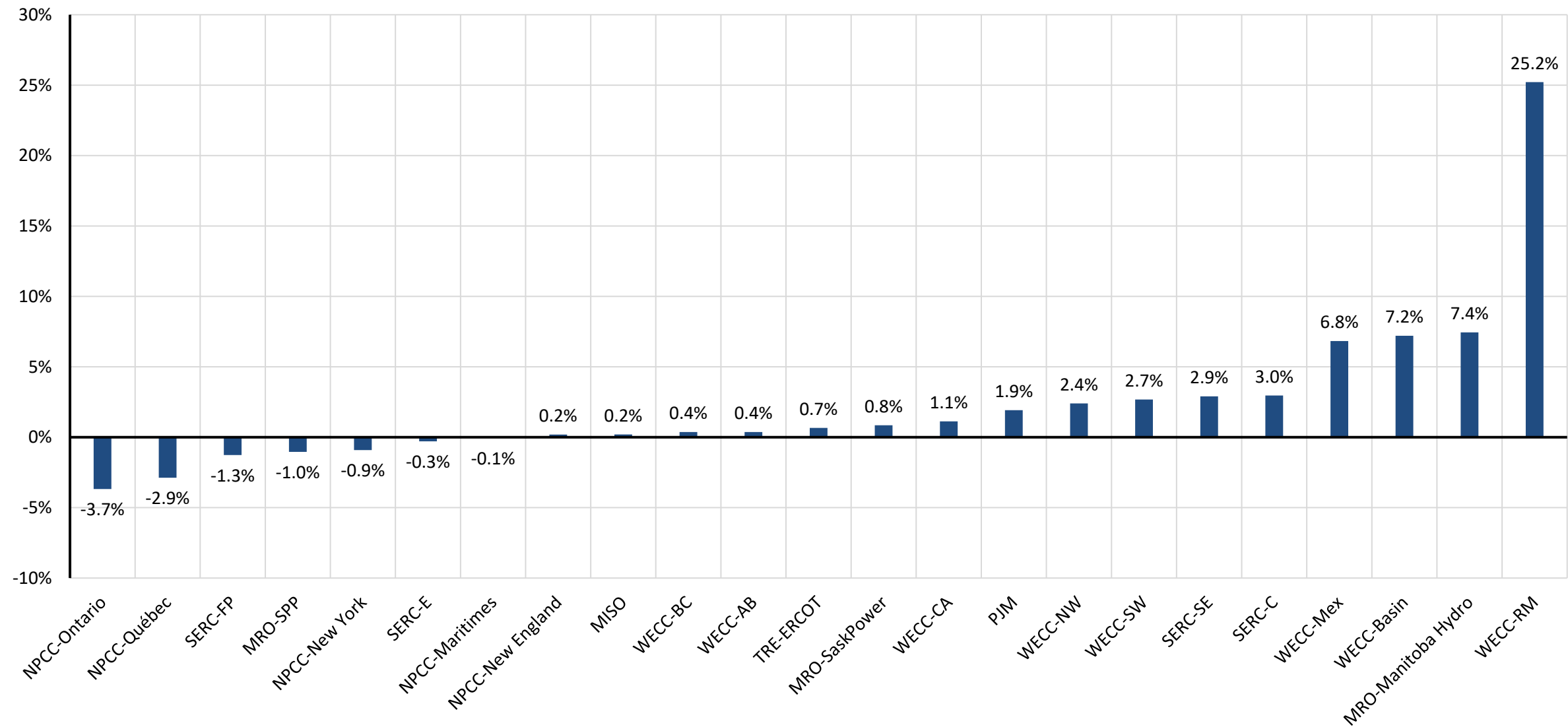


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

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-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-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-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 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-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-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

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-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

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

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

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

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-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-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-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-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

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

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 States¹⁸ 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 GW (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	4,565	5,599	5,858	4,981	4,412
		125.8					
MRO-Manitoba Hydro	3.6	3.1	50	48	0	0	290
		3.3					
MRO-SaskPower	3.7	3.5	170	208	22	6	0
		3.7					
MRO-SPP	54.3	55.3	10,869	5,876	442	486	6,046
		57.5					
NPCC-Maritimes	3.5	3.3	428	262	21	-	777
		3.6					
NPCC-New England	24.3	24.6	174	122	167	1,111	1,496
		26.5					
NPCC-New York	29	30.3	130	340	0	53	1,451
		32					
NPCC-Ontario	23.9	21.8	915	720	260	66	1,174
		23.7					
NPCC-Québec	23	22.9	2,270	-	0	-	10,500*
		24					
PJM	153.1	143.5	3,366	1,703	2,709	5,694	6,402
		156.9					
SERC-C	42.3	40.7	312	172	813	996	959
		43.9					
SERC-E	44	42.6	0	-	3,009	2,405	1,878
		44.7					
SERC-FP	52.4	50.5	0	-	5,376	5,643	
		53.6					
SERC-SE	44.9	44.4	0	-	3,507	7,217	1,007
		45.3					
TRE-ERCOT	85.5	81.3	6,286	9,070	17,566	17,797	3,622
		82.3					
WECC-AB	12.2	12.2	1,091	666	1,114	786	_**
		12.7					
WECC-BC	9.4	9.3	257	140	0.94	0	_**
		9.8					

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	1,633	1,124	10,112	13,147	921
		61.6					
WECC-NW	59.7	63	4,694	2,964	6,339	2,595	3,655
		69.7					
WECC-SW	30.8	26.4	1,179	542	3,357	1,294	2,042
		28.8					
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**

NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

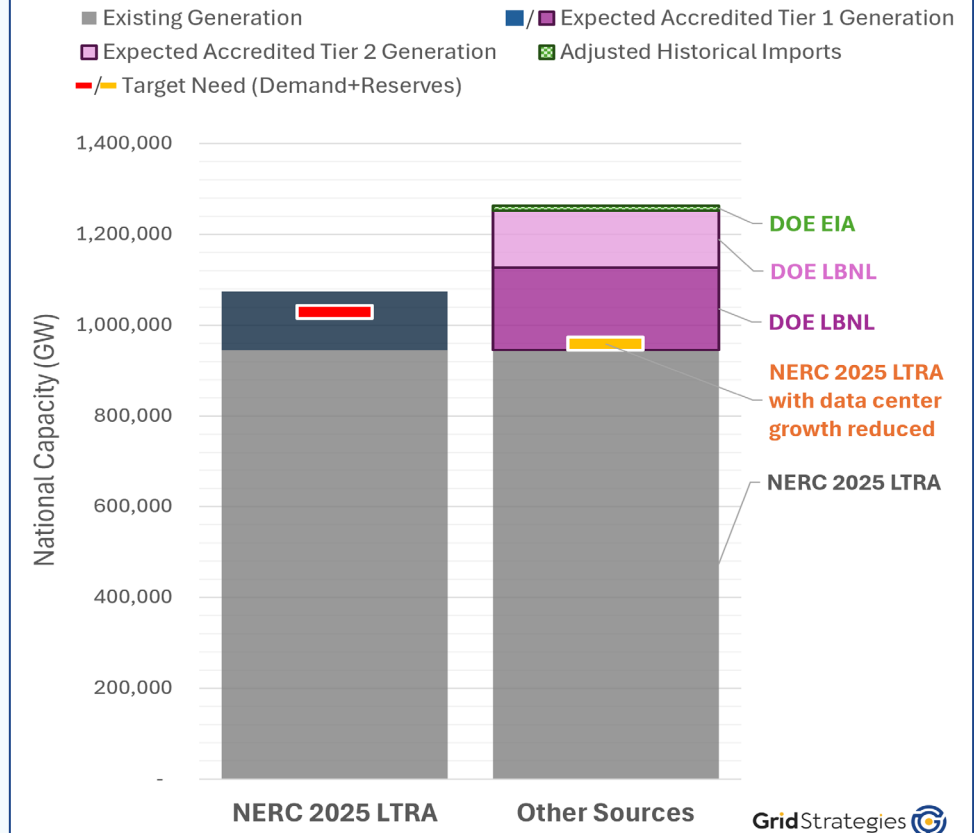
A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- 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.

Will there be enough capacity to meet 2030 summer needs?
NERC's 2025 LTRA compared against other data sources.



Historic Trends in NERC Assessment Data

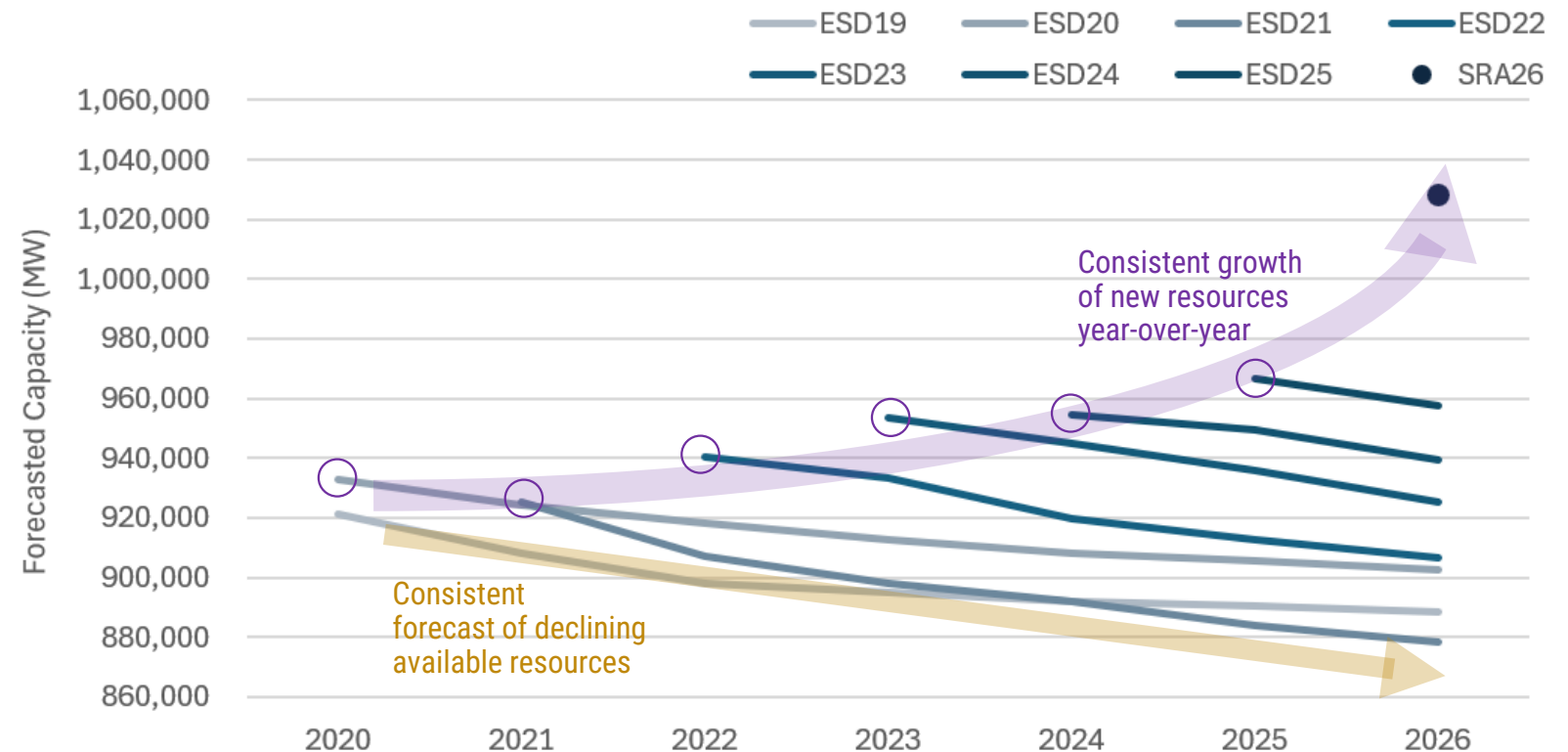
New generation resources added to the grid continue to surpass NERC reliability assessment expectations year after year.

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.

Forecasted certain on-peak resources | Sum of all regions

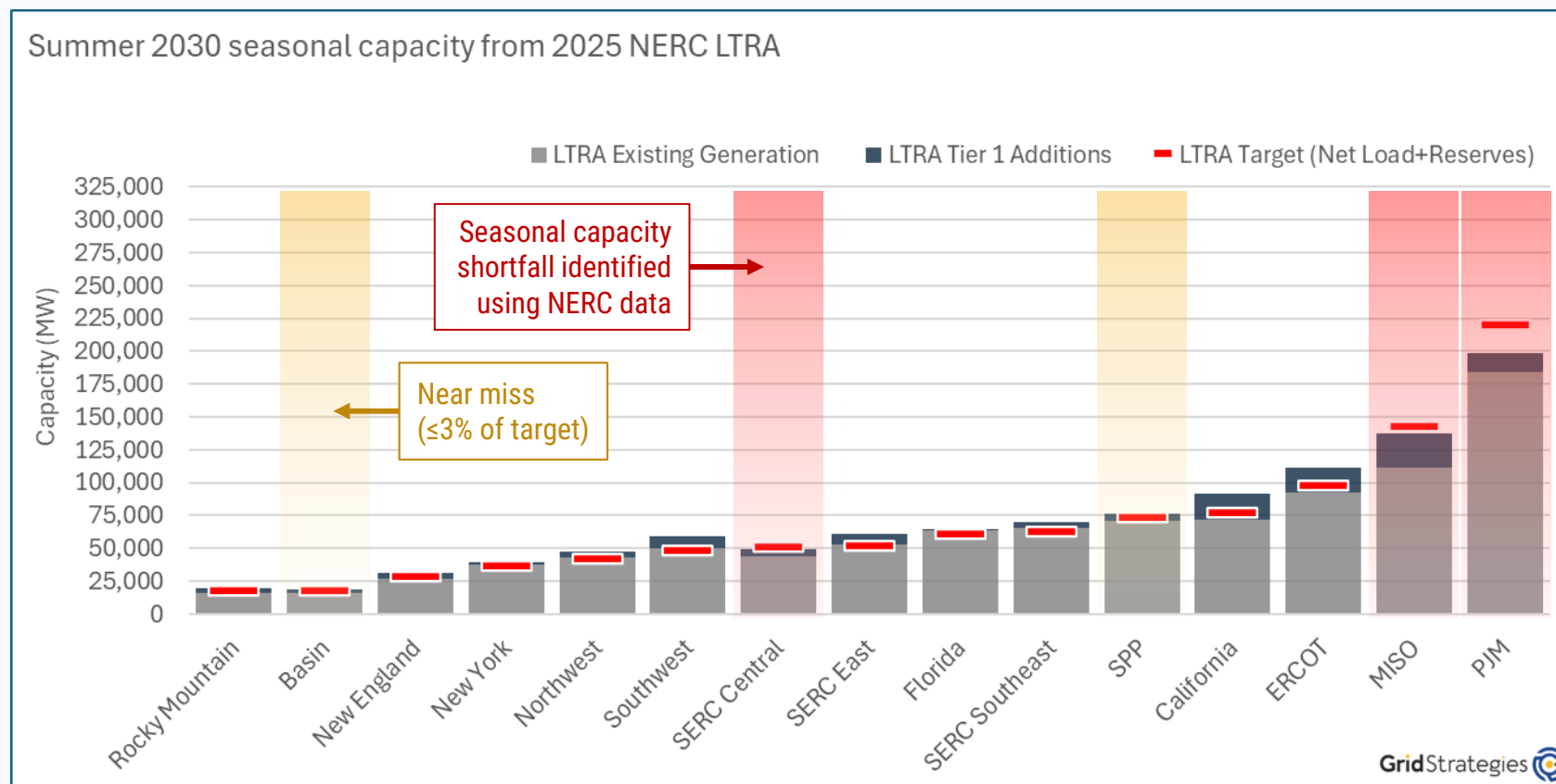


Regional RA Assessments for Summer 2030

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.

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



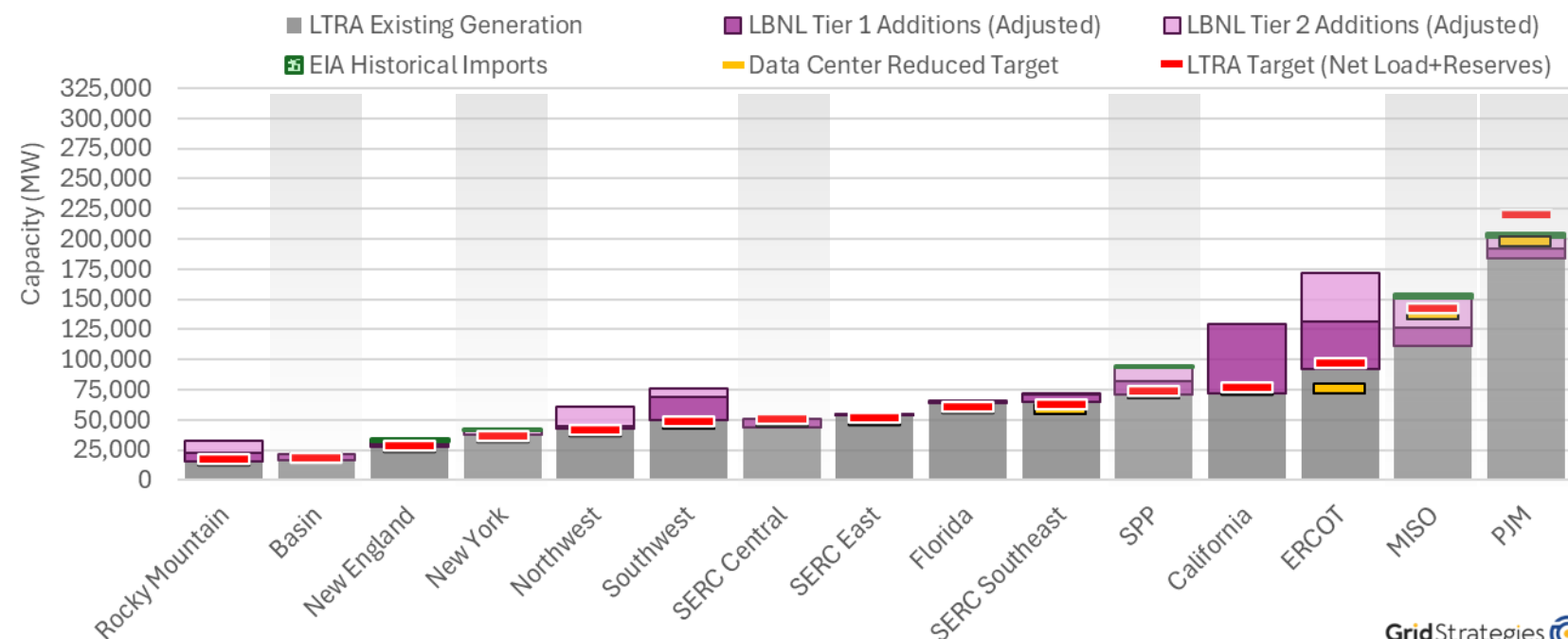
Consideration of historic non-firm imports during extreme events

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



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



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

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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**

NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

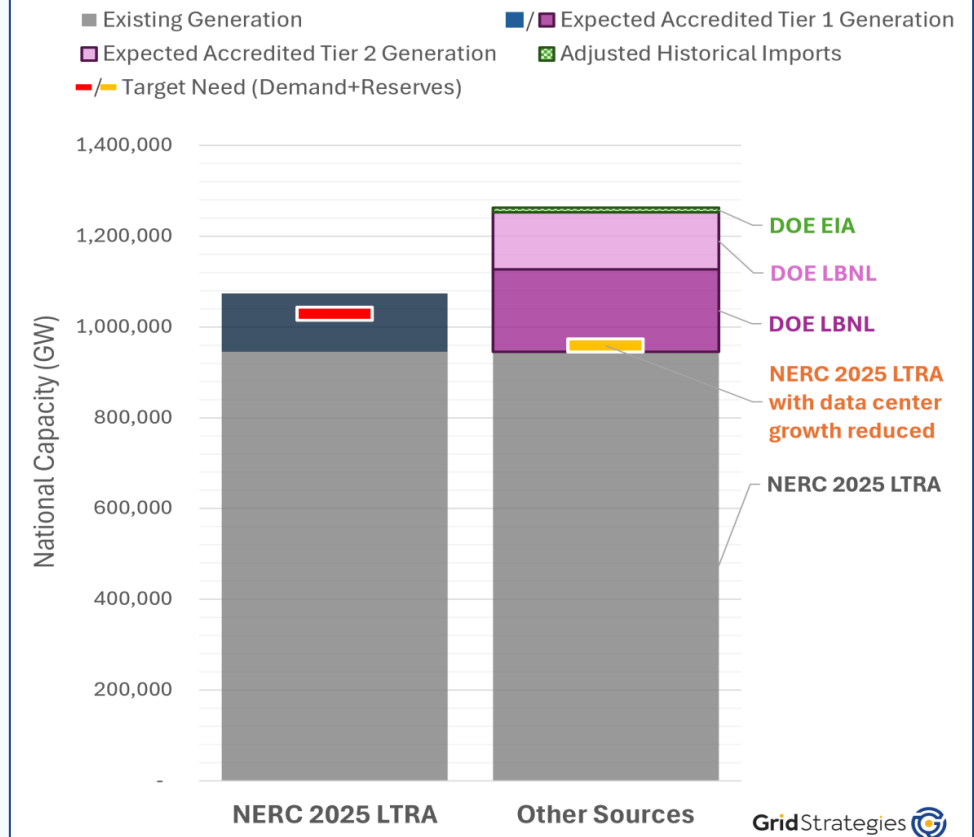
A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- 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. This chart is explained in the Methodology.

Will there be enough capacity to meet 2030 summer needs?
NERC's 2025 LTRA compared against other data sources.



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:

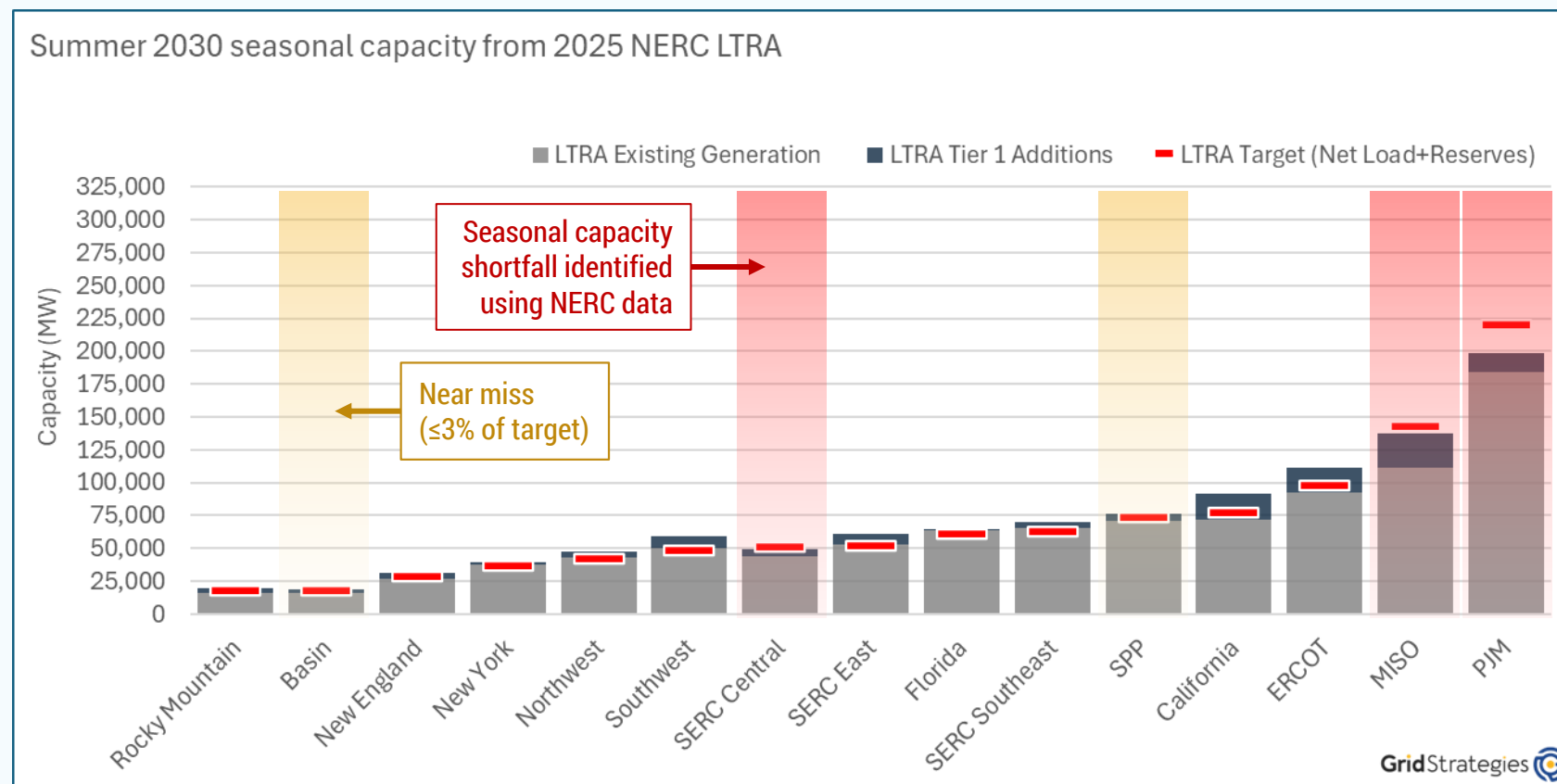
- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

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.

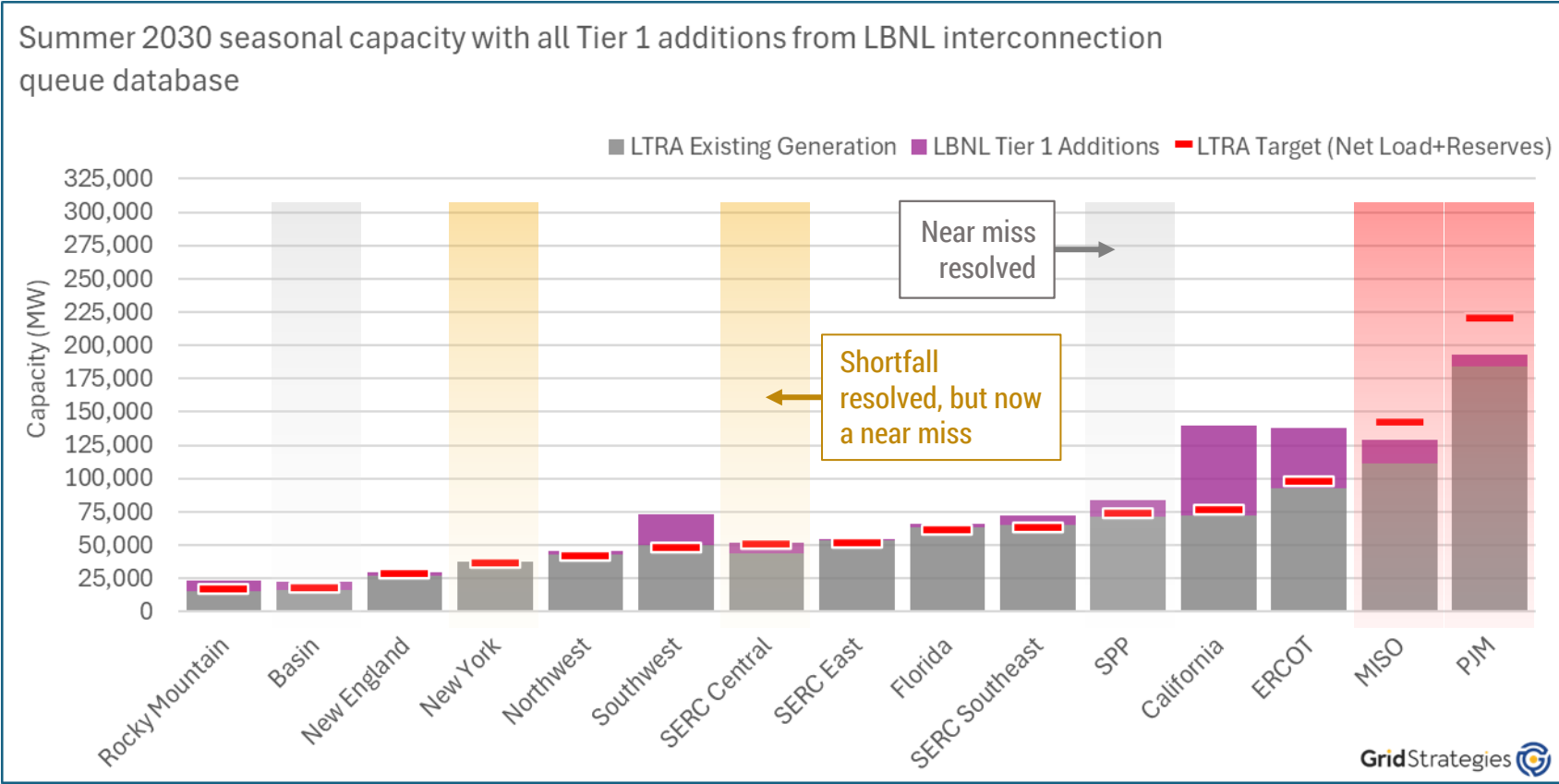


*NERC did not identify SERC Central as a heightened risk region though it is shown to be short of future capacity using the LTRA source data, perhaps because they did not identify elevated energy inadequacy risk despite the seasonal capacity shortfall in the region. We highlight it as elevated risk given the identified seasonal capacity shortfall.

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.



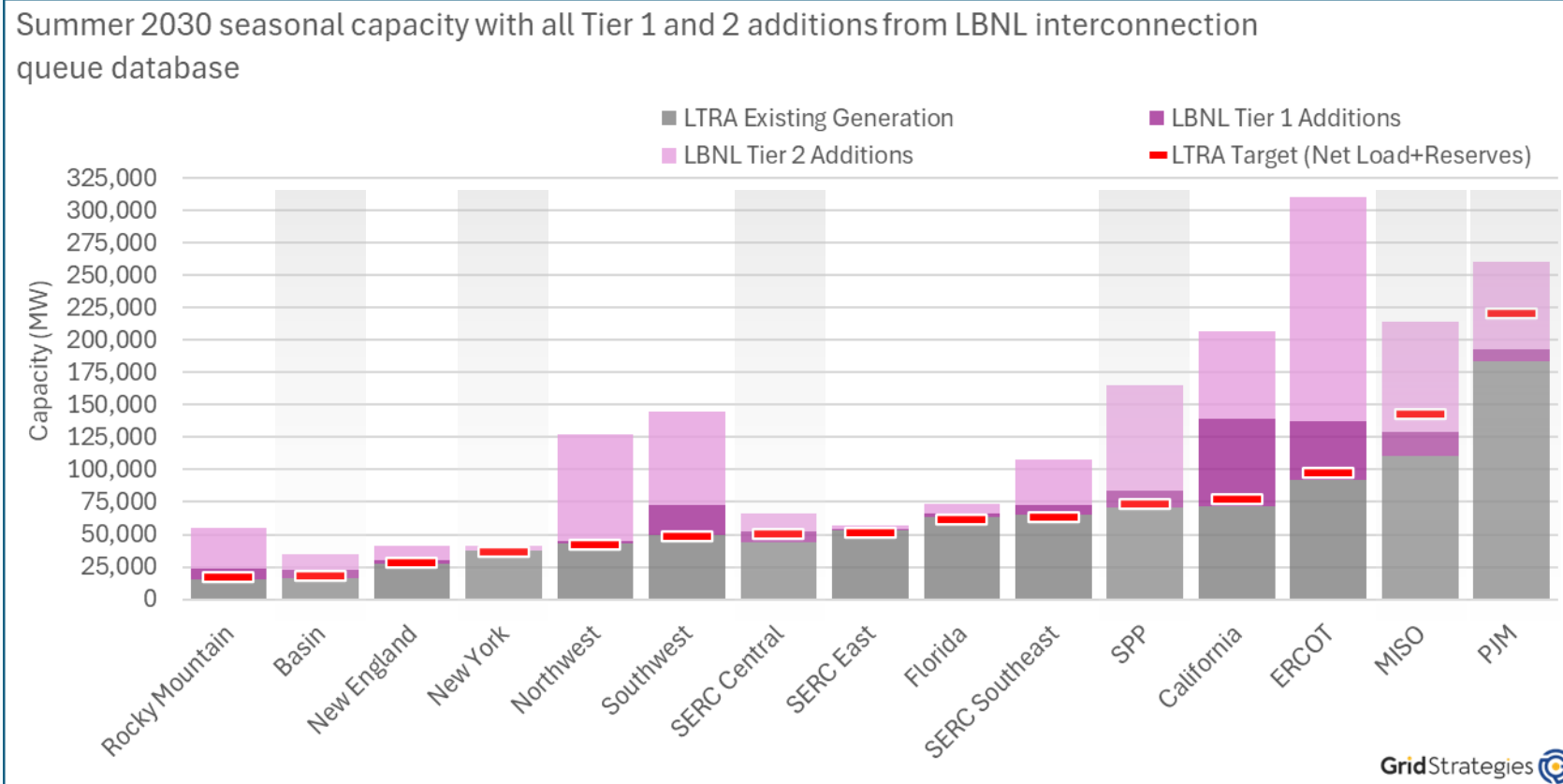
*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. Utilities do not uniformly report seasonal or resource-specific accredited capacity to NERC for use 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.

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.

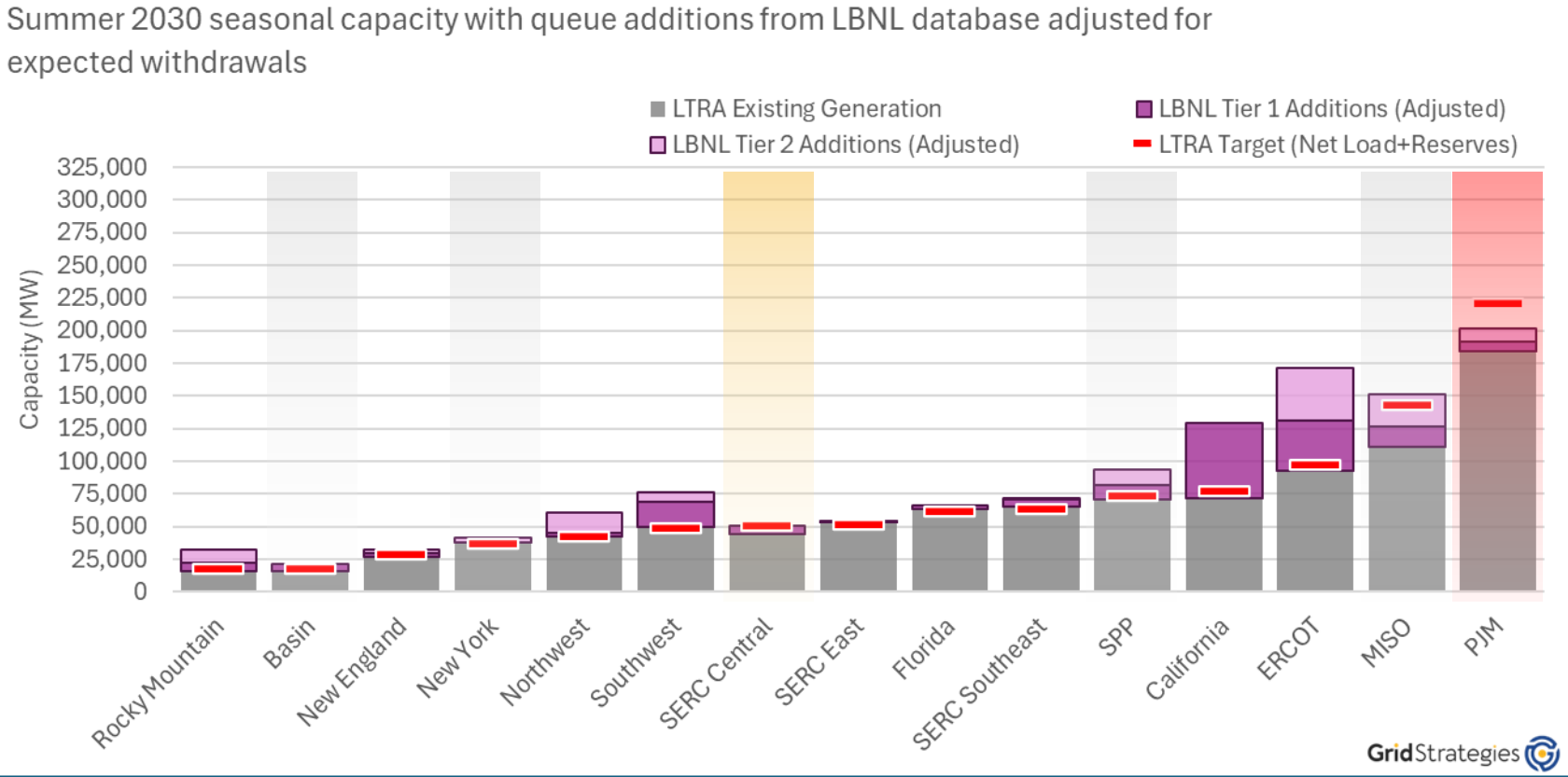


Even when accounting for likely resource cancellations in the queue and post-queue phases, LBNL data suggests enough resources could connect to meet most regions' 2030 capacity needs.

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.

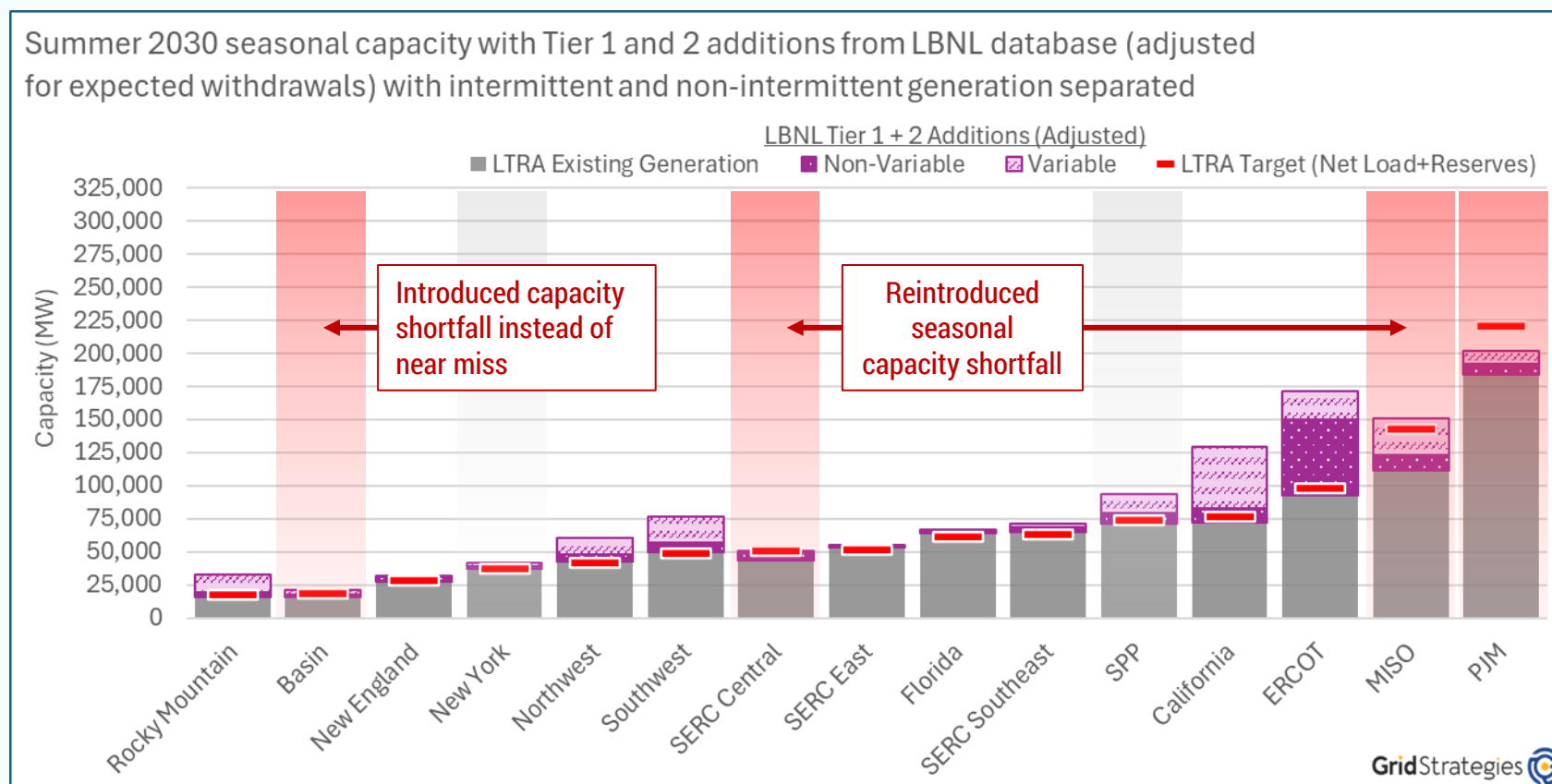


Delays in the study, permitting, and/or construction phases to resources already in the queues—including wind and solar facilities—could jeopardize meeting regional seasonal capacity needs.

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.



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.



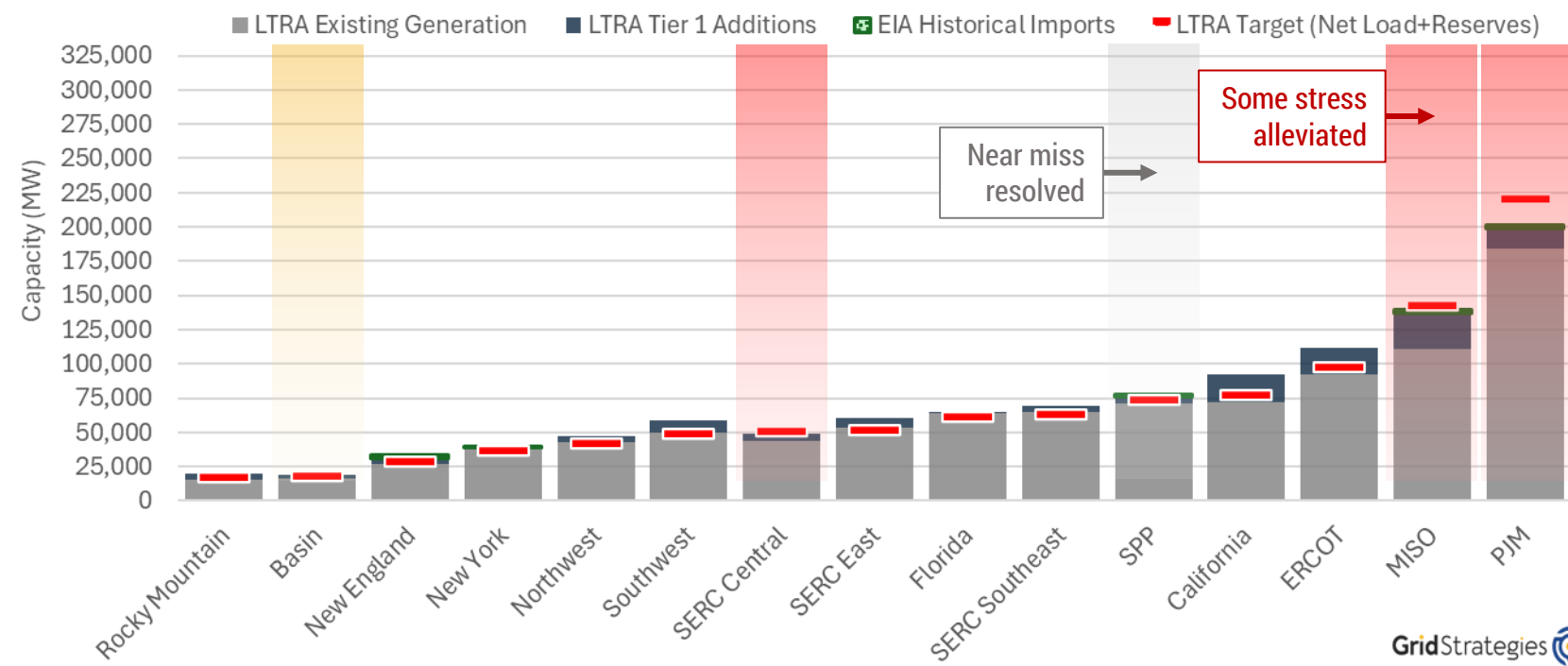
The LTRA only counts firm imports, omitting non-firm imports. Some regional stress is alleviated when combining the LTRA capacity assumptions with historical non-firm import availability.

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.

Summer 2030 seasonal capacity with interregional import capacity adjusted to reflect regional historical imports

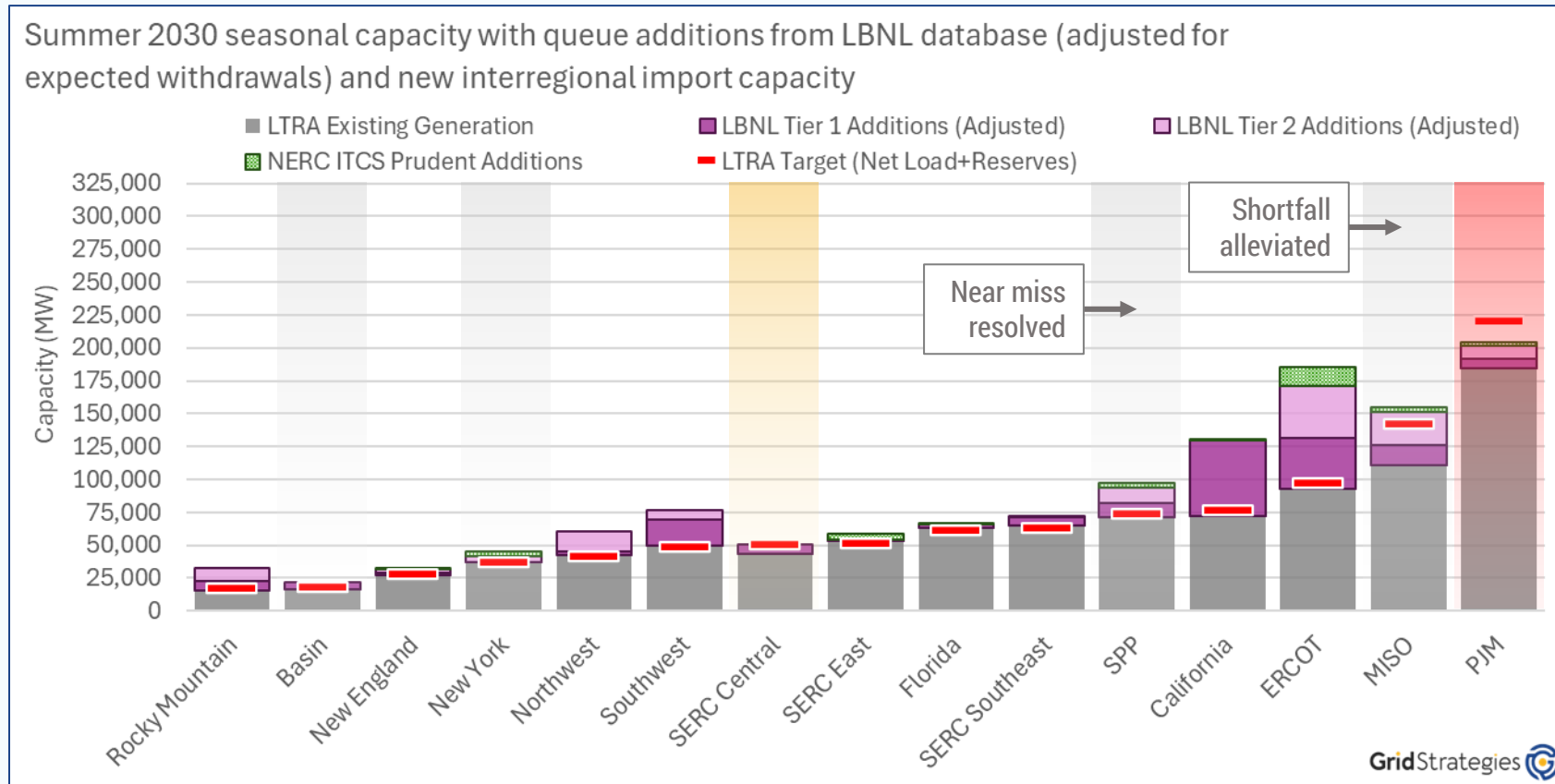


The combination of NERC-identified increased transfer capability and reasonable resource assumptions from the interconnection queues provides even more security to avoid shortfalls.

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.



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.

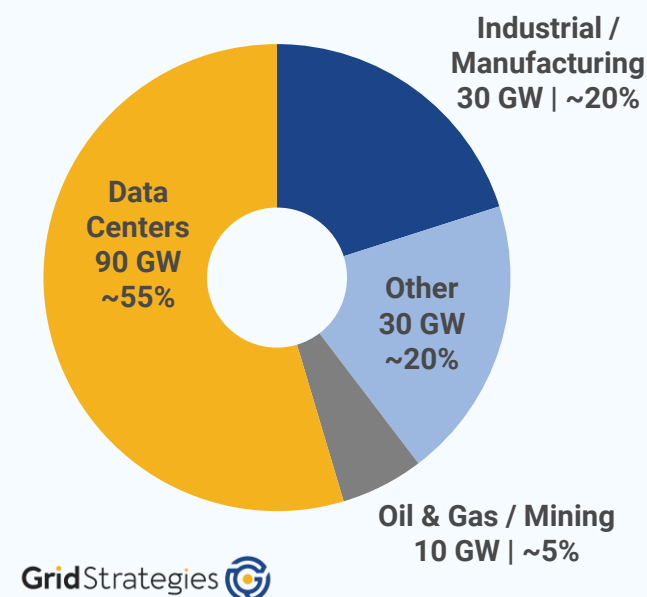
- Data centers, in particular, are constrained by global supply chains. There is no clear method for individual load forecasts to account for how supply chain constraints will affect specific projects.
- Load forecasts lack visibility into customers' overall business plans. There may be "double counting" 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.

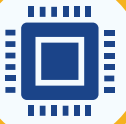
Time lags: Producing and compiling load growth projections occurs months before the LTRA is released. Mounting delays in large load interconnection and policy changes appear to have slowed load growth since their compilation.

- 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.

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%.

**Drivers of Load Growth
(2025 – 2030)**



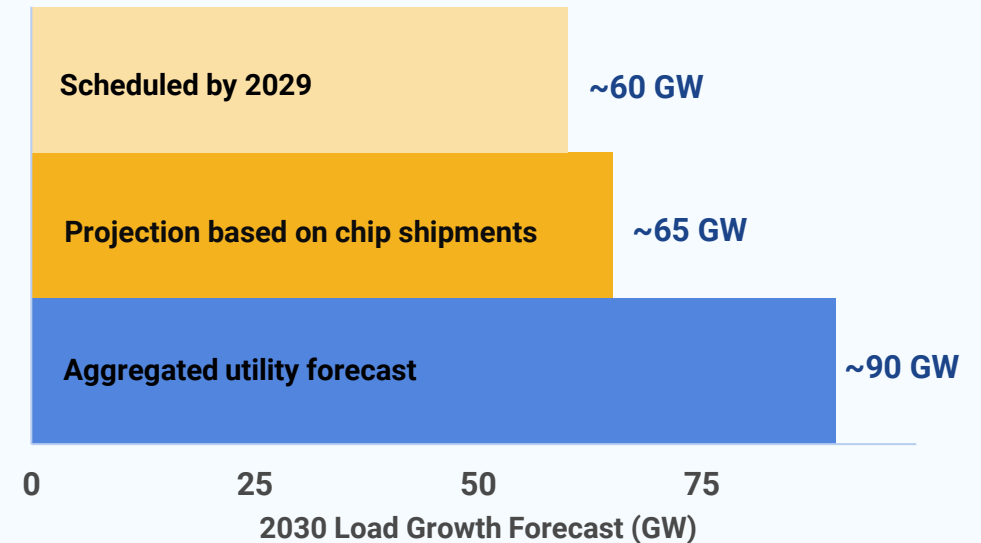


Assumed data center load

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.

Alternative Benchmarks for Data Center Load Growth



GridStrategies



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.

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.

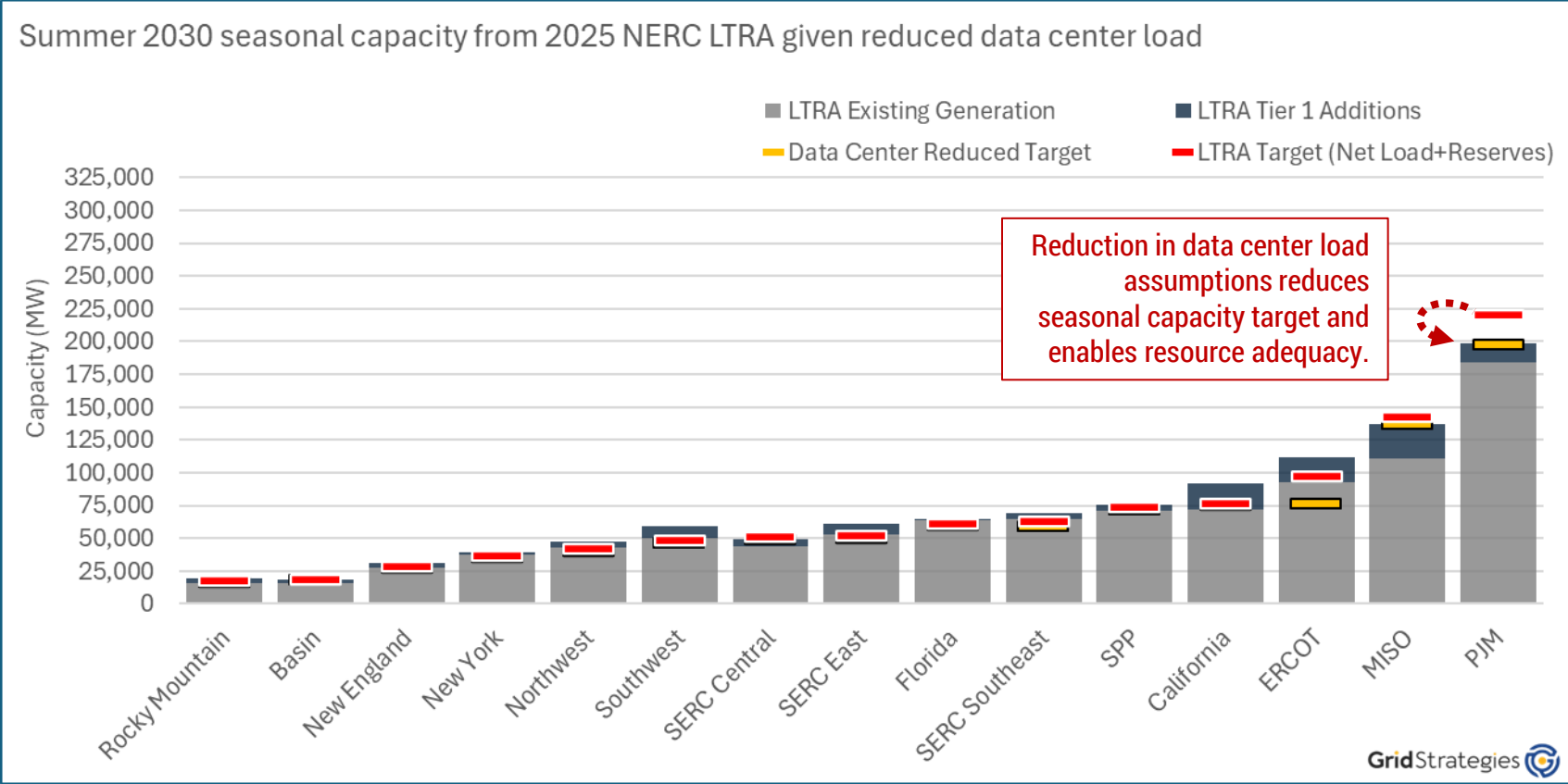
Updating data center load forecasts based on chip-industry forecasts would allow nearly all regions to meet their 2030 target needs

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.



Extreme Event Energy Adequacy

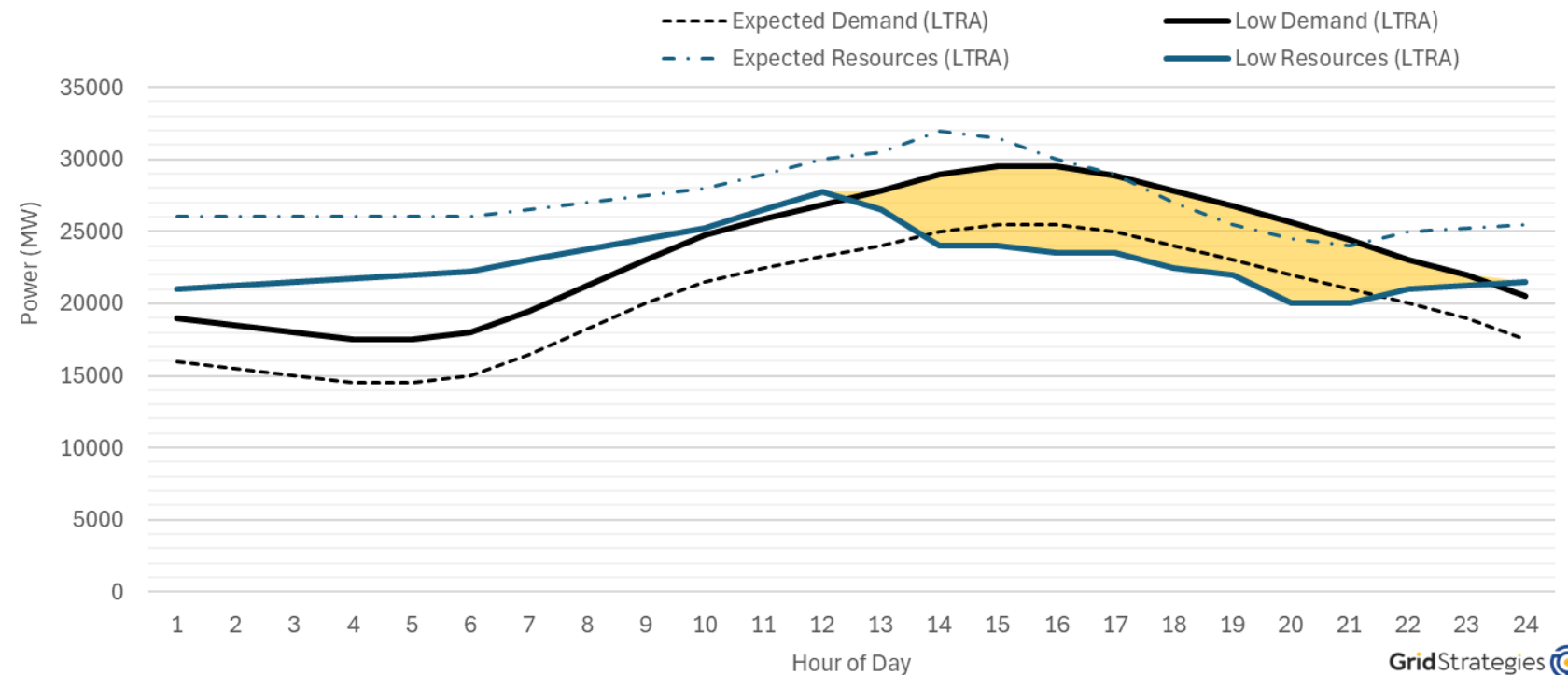
Energy inadequacy risk during extreme events can exist even without seasonal capacity shortfalls. An increase in resource and interregional transfer capability also helps to alleviate extreme event risk.

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.

2029 unserved energy day for New England from NERC LTRA



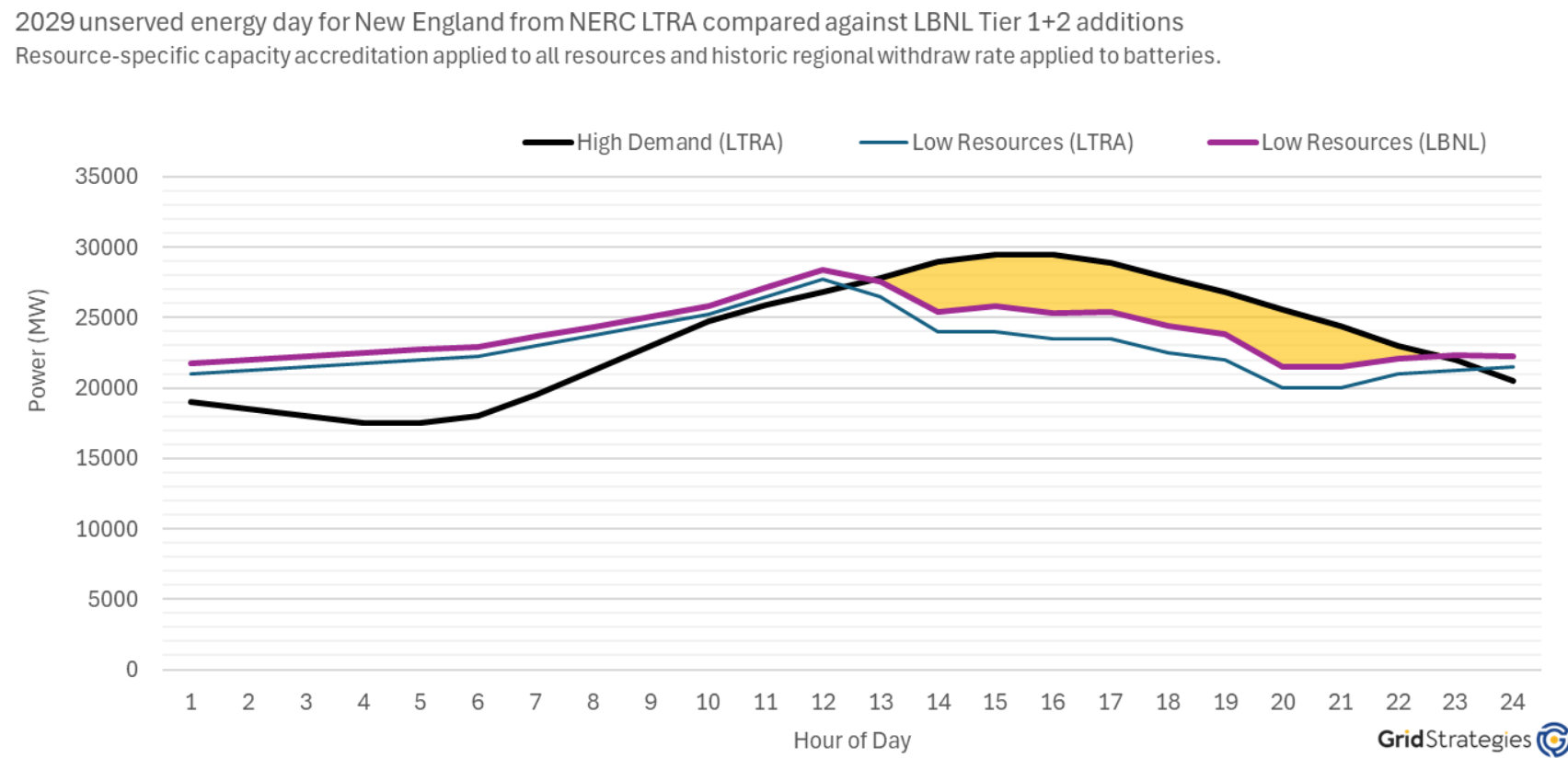
*This figure is a recreation of the extreme event energy analysis shown in the LTRA for New England. We did not independently reproduce this analysis.

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.

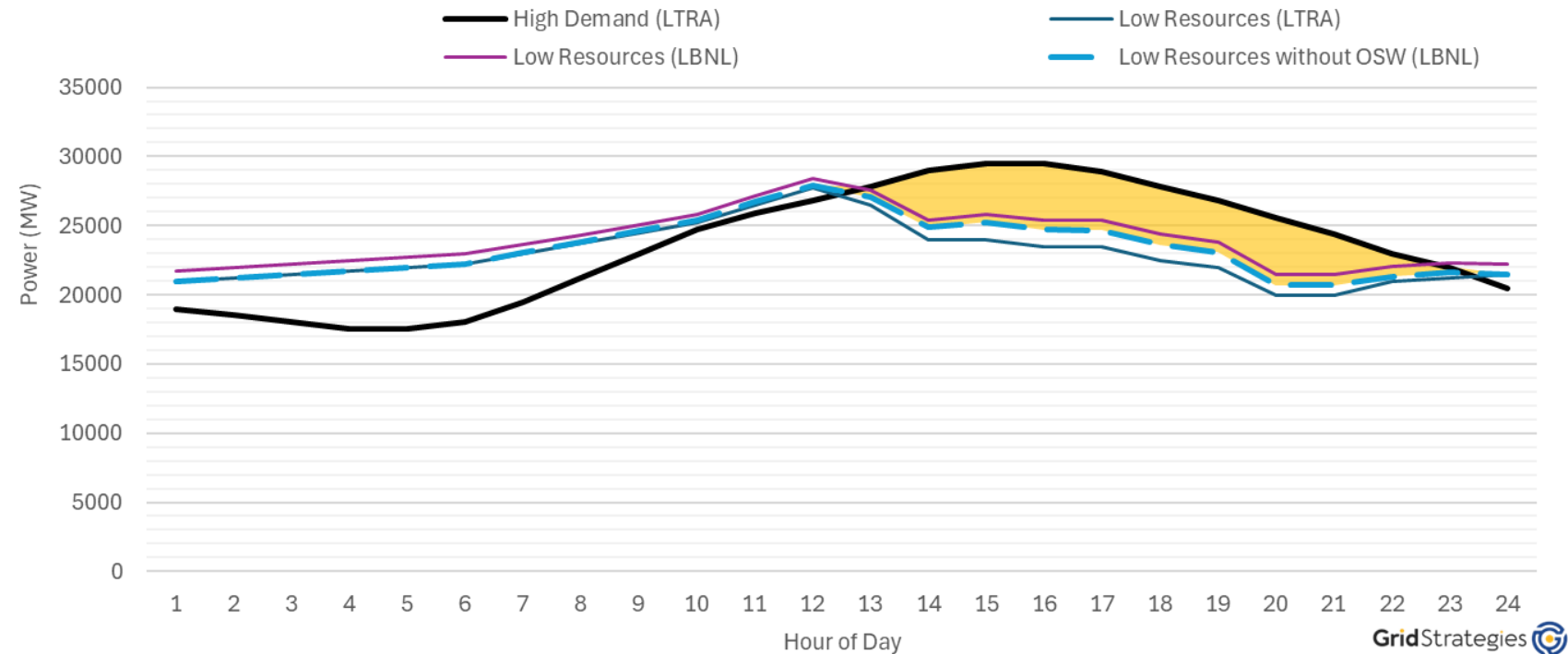
As with seasonal capacity adequacy, permitting and/or construction delays of resources with executed IAs are likely to exacerbate energy inadequacy risk during extreme grid events.

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.

2029 unserved energy day for New England from NERC LTRA compared against LBNL Tier 1+2 additions (accredited and adjusted) without offshore wind



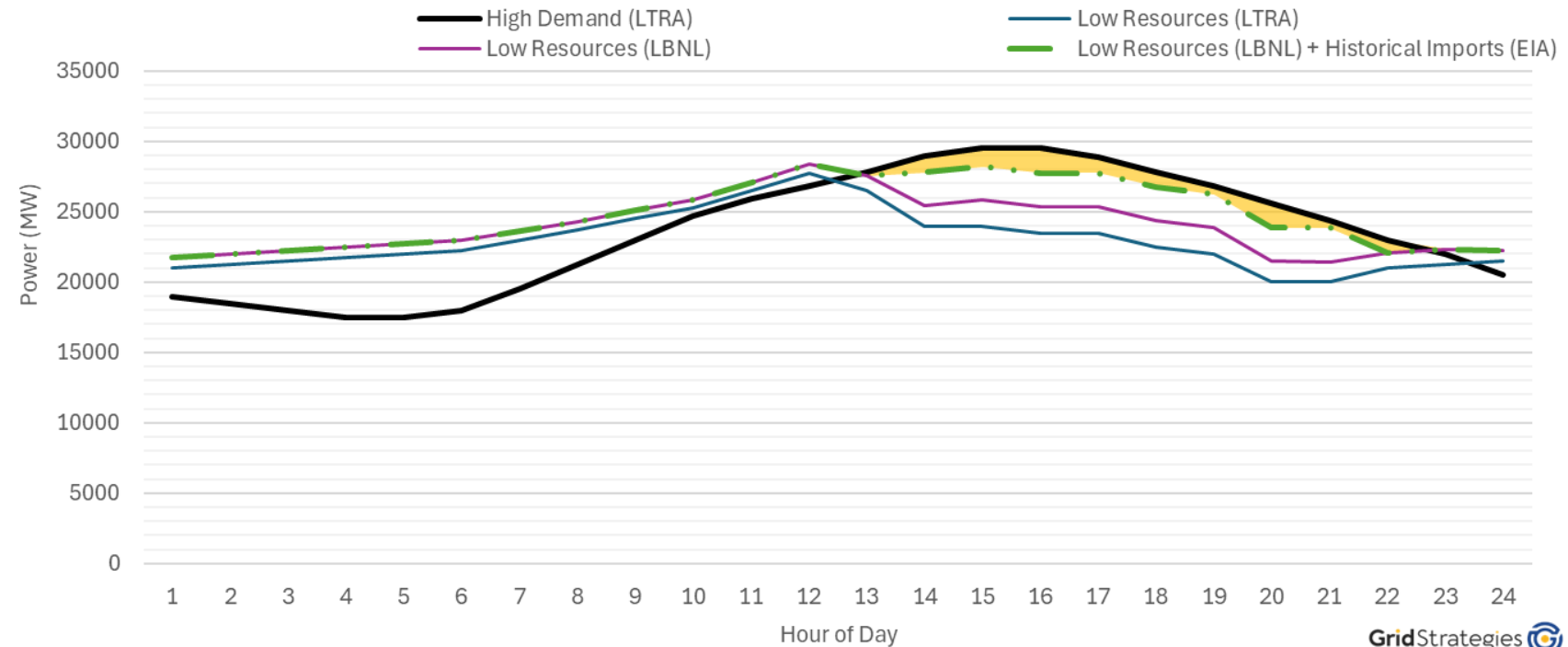
Interregional transmission designed to move power between regions during times of grid stress further reduces unserved energy risk.

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.

2029 unserved energy day for New England from NERC LTRA compared against LBNL Tier 1+2 additions (accredited and adjusted) and historical import availability from EIA



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



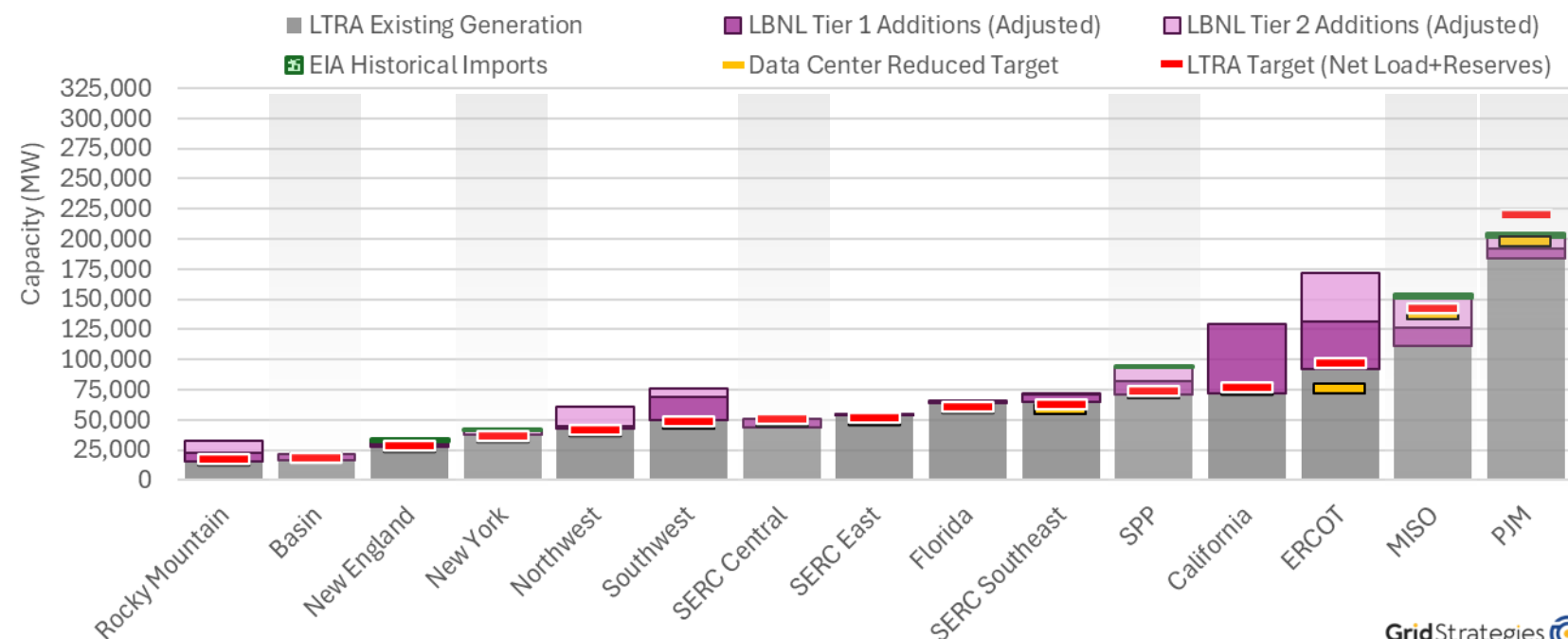
Consideration of historic non-firm imports during extreme events

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



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

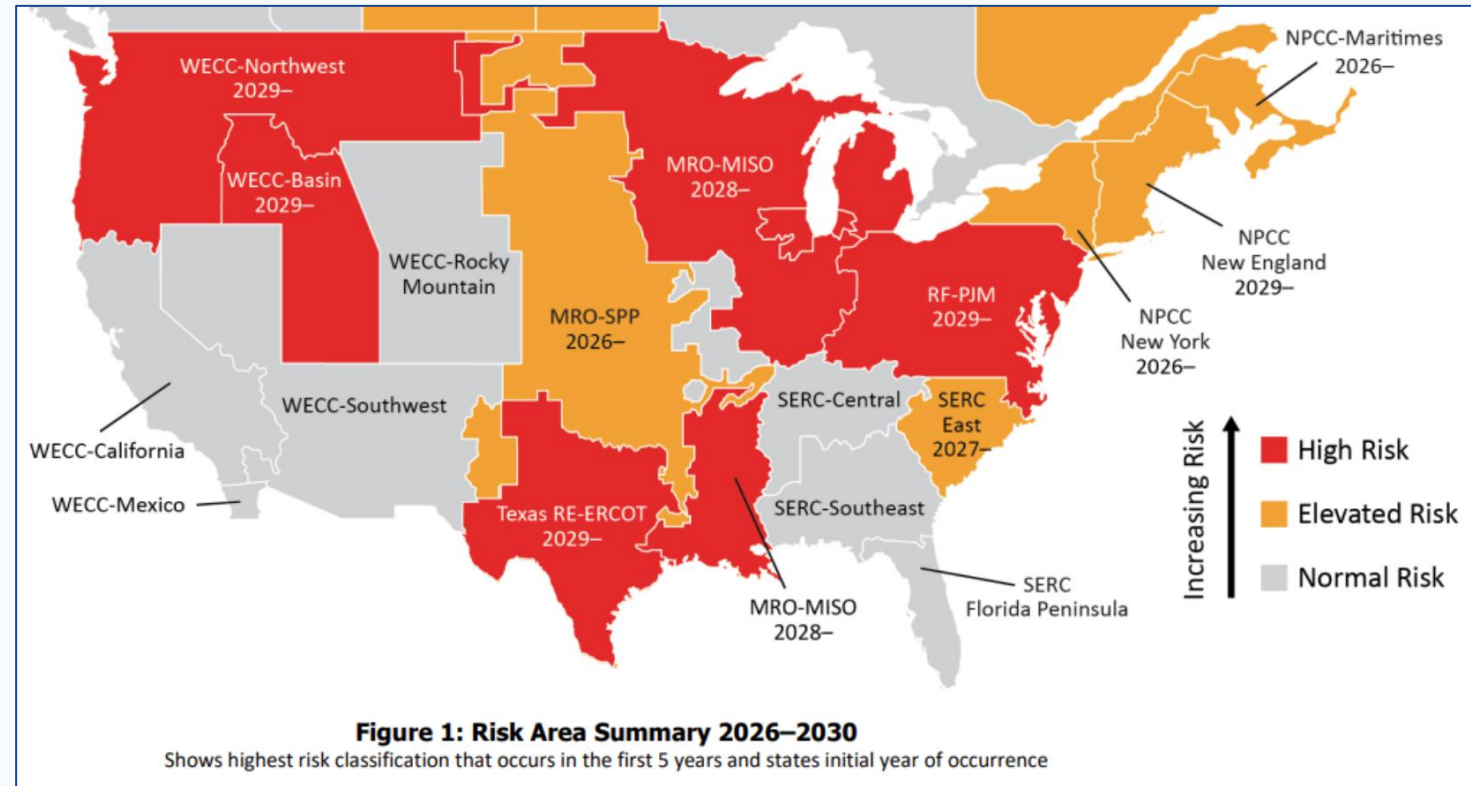
The NERC LTRA assesses each region's ability to meet both its future capacity and energy adequacy needs.

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

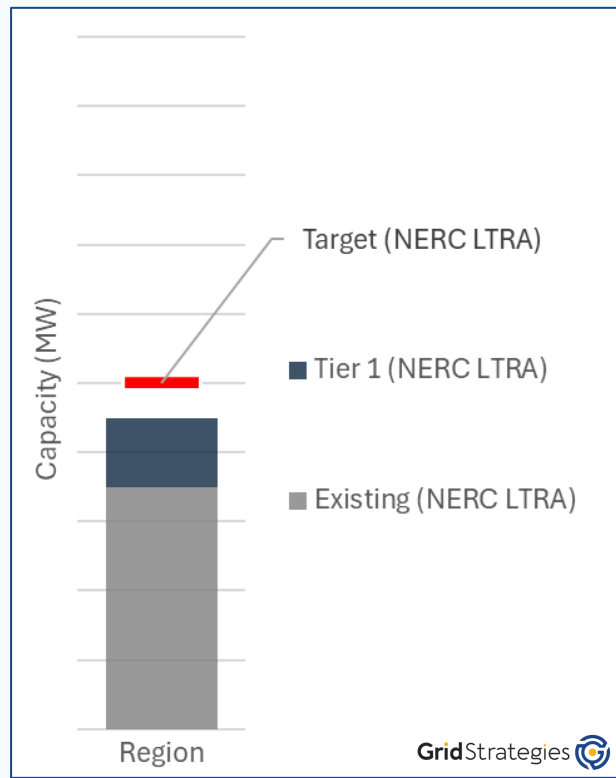


*NERC did not mark SERC-Central as elevated risk despite showing large seasonal shortfalls while SPP was marked as elevated risk despite having neither seasonal capacity shortfalls nor extreme event energy shortfalls.

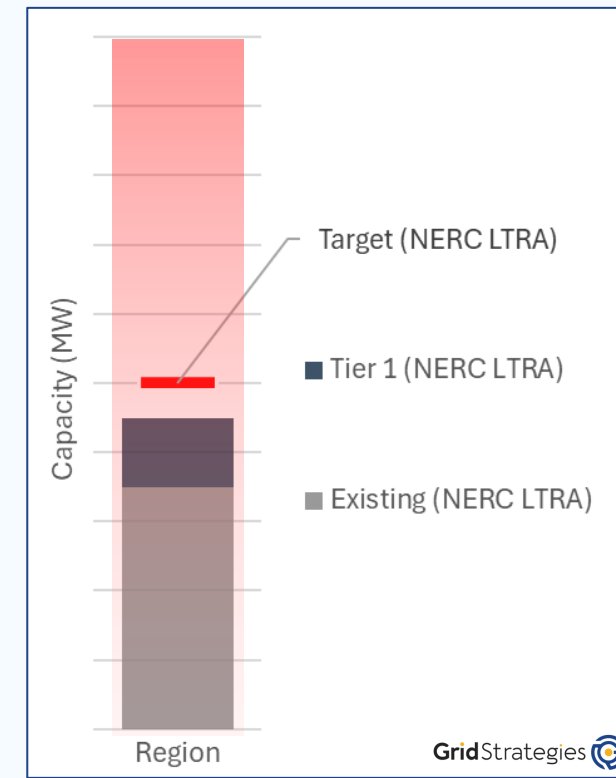
Illustrative walkthrough of seasonal capacity slides

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.”



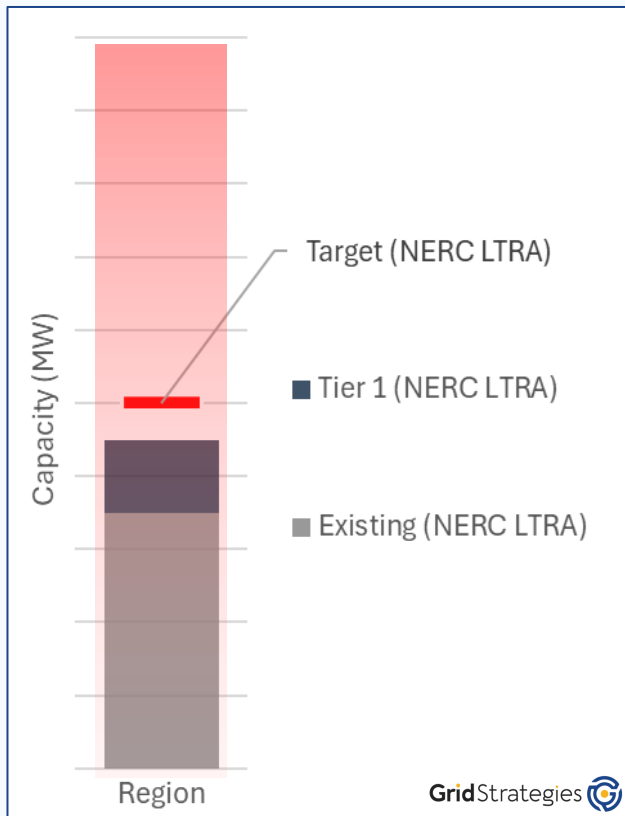
Highlight important features of chart



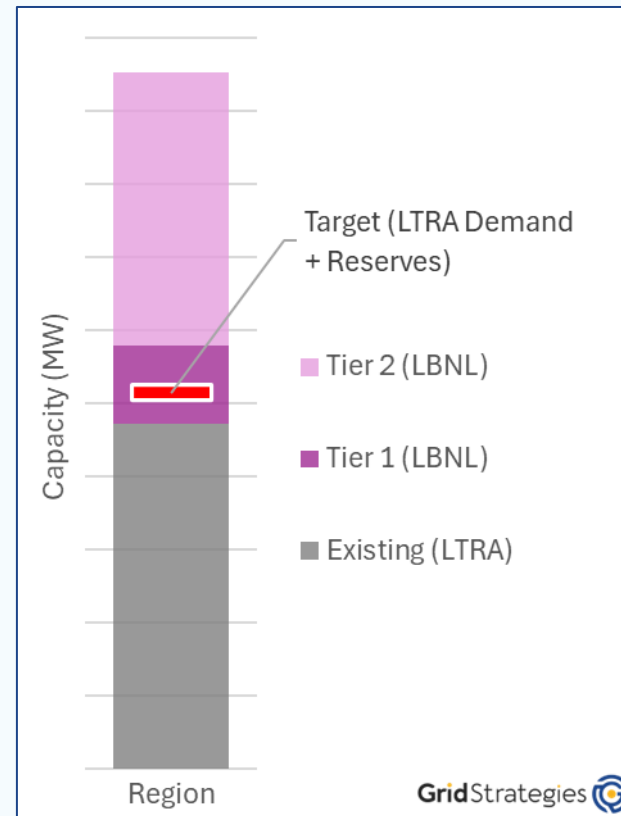
Illustrative walkthrough of seasonal capacity slides

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.

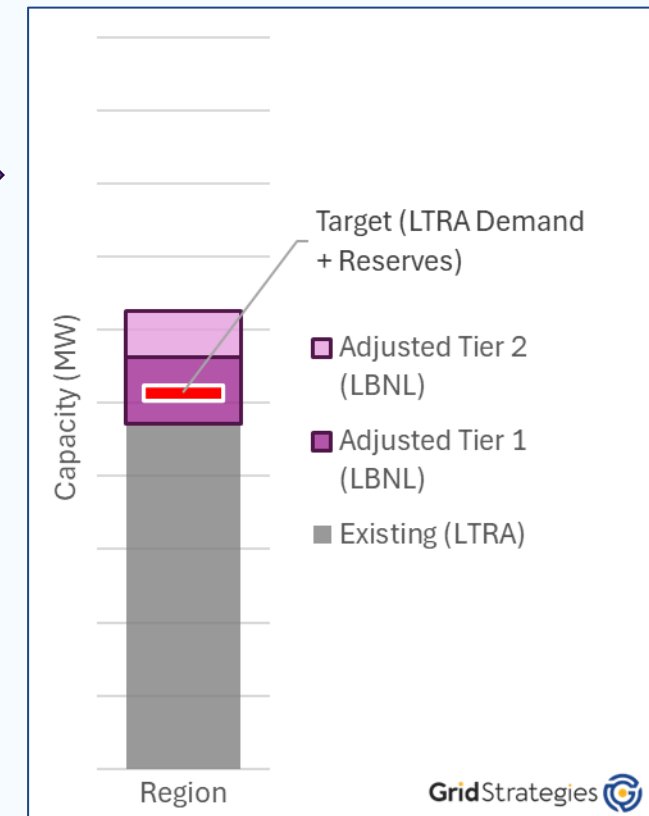
To avoid overcounting queue generation, the LBNL data is discounted based on regional- and study phase-specific withdraw rates.



Replace NERC data with resource-accredited LBNL data



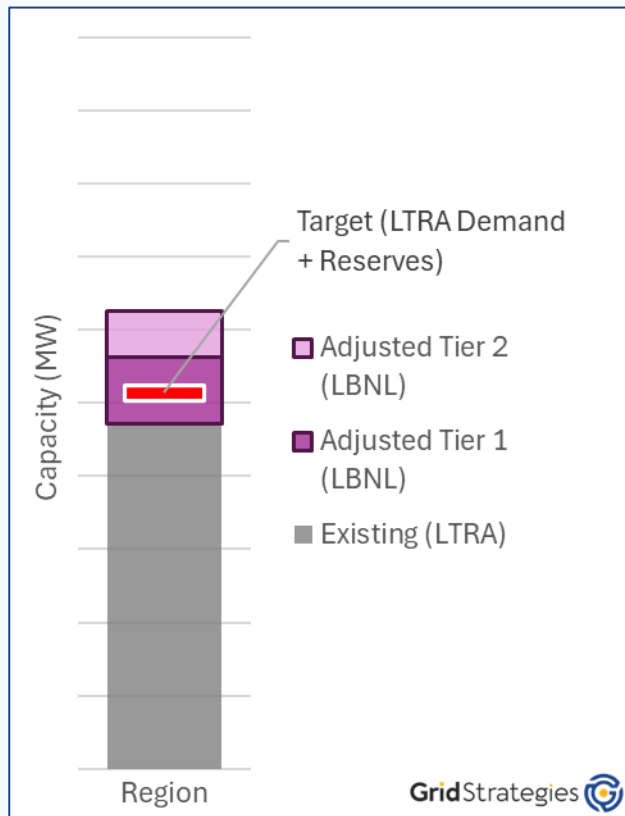
Reduce LBNL data based on expected withdraws



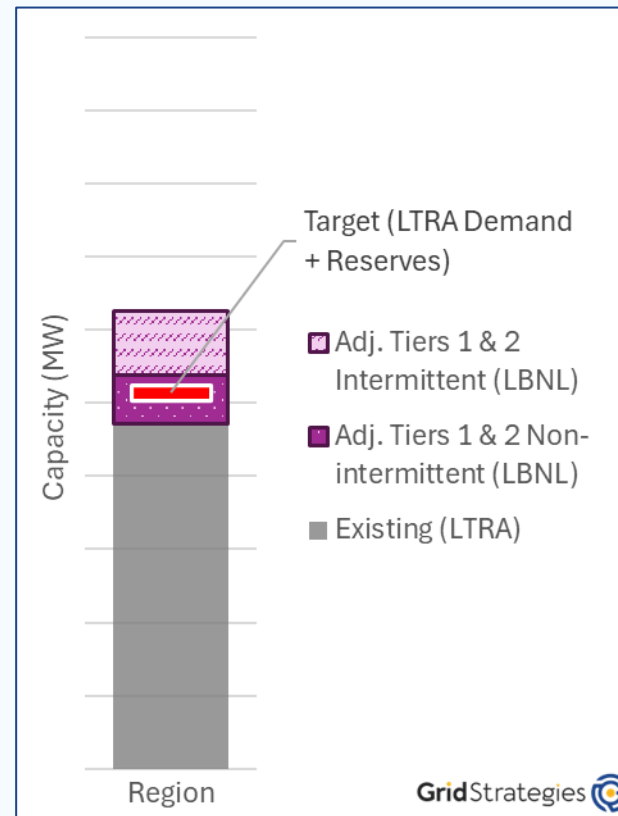
Illustrative walkthrough of seasonal capacity slides

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.

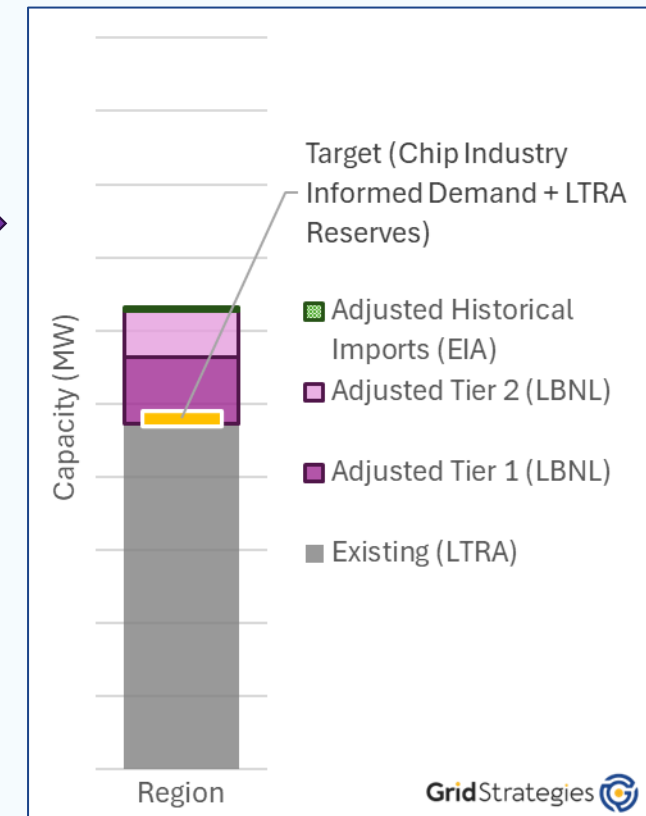
Interregional transfer capability data is adjusted using EIA data to better illustrate available capacity. In some cases, the expected load is changed to match demand forecasts from other sources.



Look at different features of LBNL data



Continue to add more data for analysis



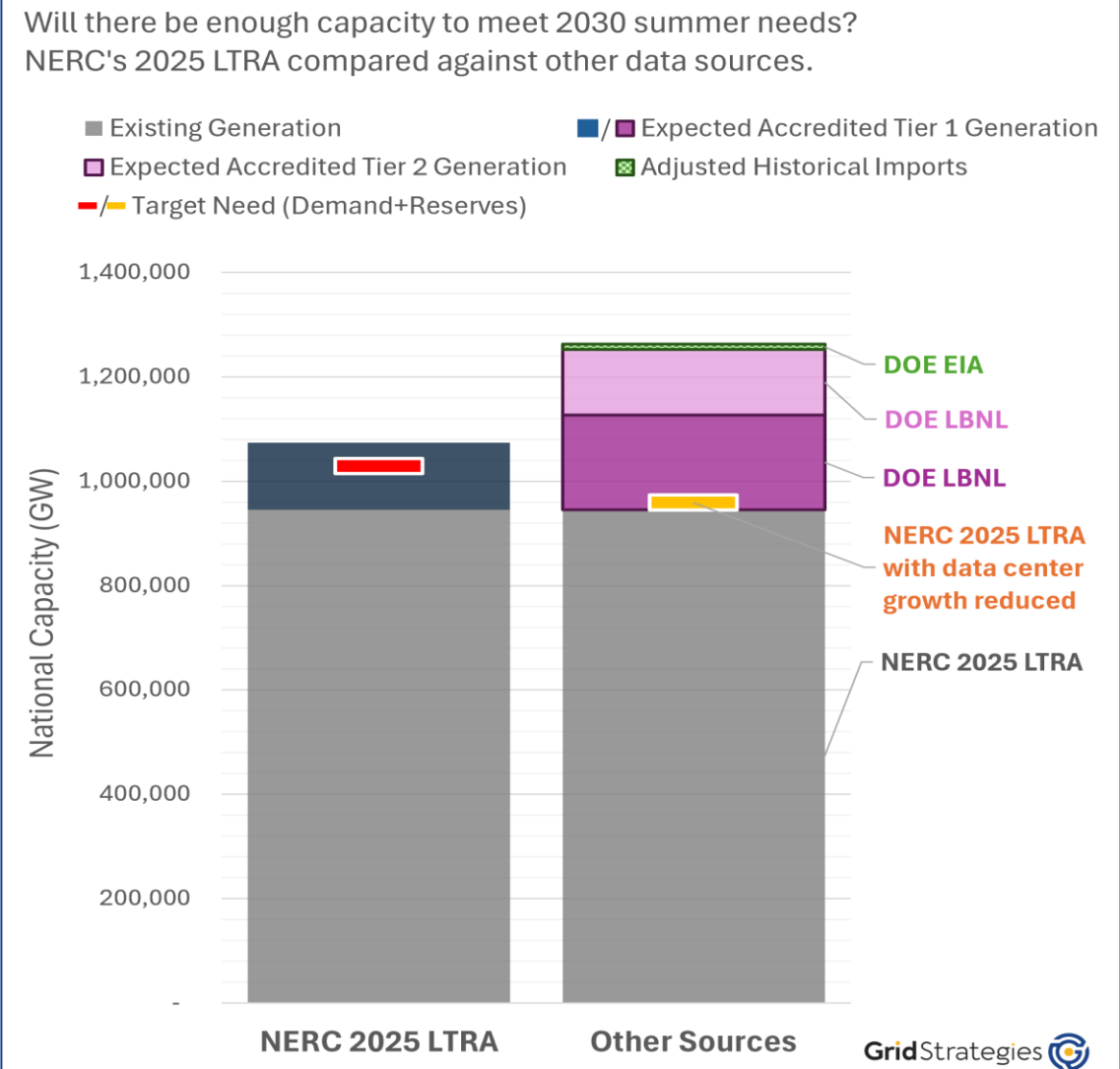
Summary slide of seasonal capacity differences in 2030

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.



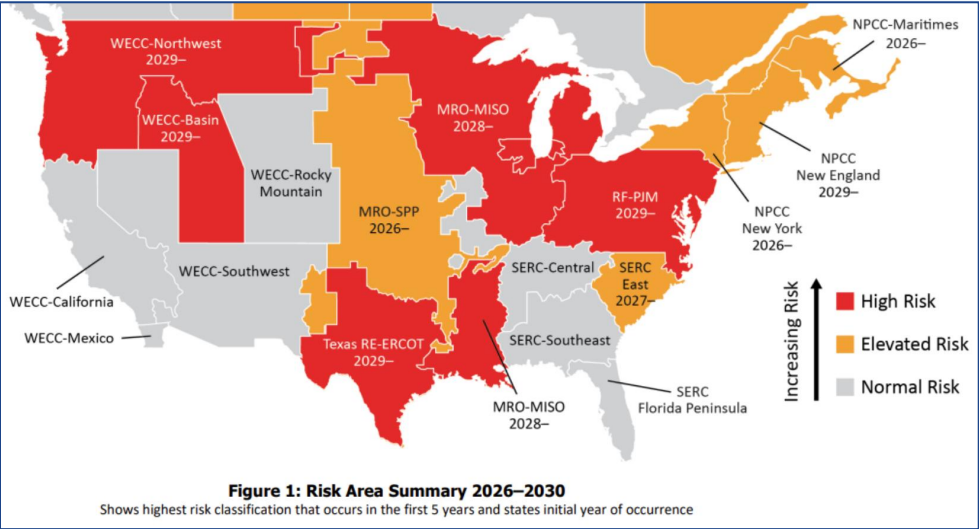
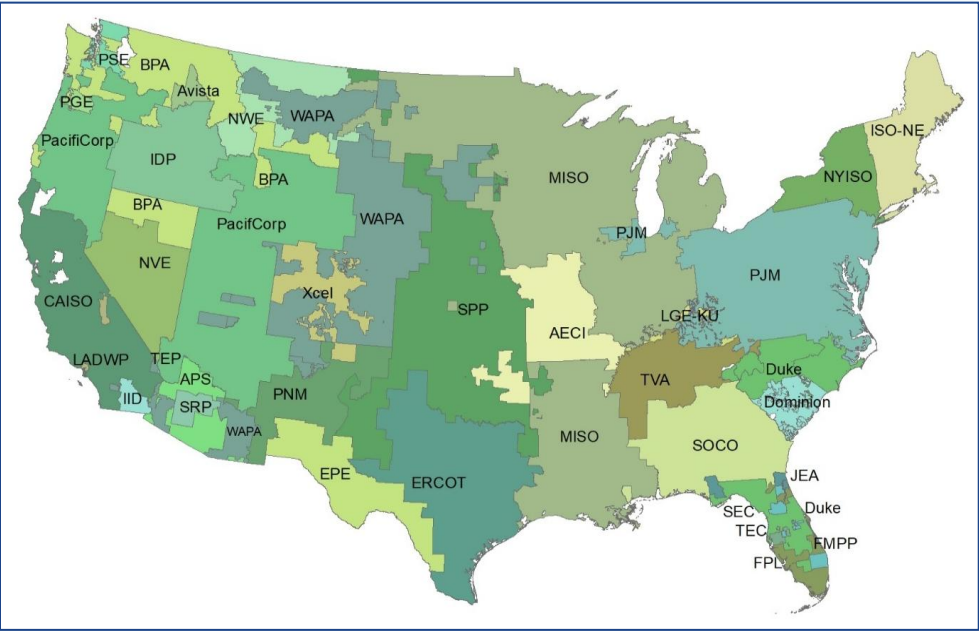
Analysis using LBNL data:

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 Northwest - Avista - BHP - BPA - CPUD - GrantPUD - MPC - NWMT - PGE - TPU - WAPA-IS	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
WECC Rocky Mtn - CLPT - BHCT - CSU - PacifiCorp - PRPA - PSCo - TSGT - WAPA-RM	WECC Basin IdahoPower		SERC Southeast - GTC - SOCO
			SERC Florida - OUC - TEC - Duke (FL)
			SERC East - Dominion - S-C - Duke (non-FL)



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

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%

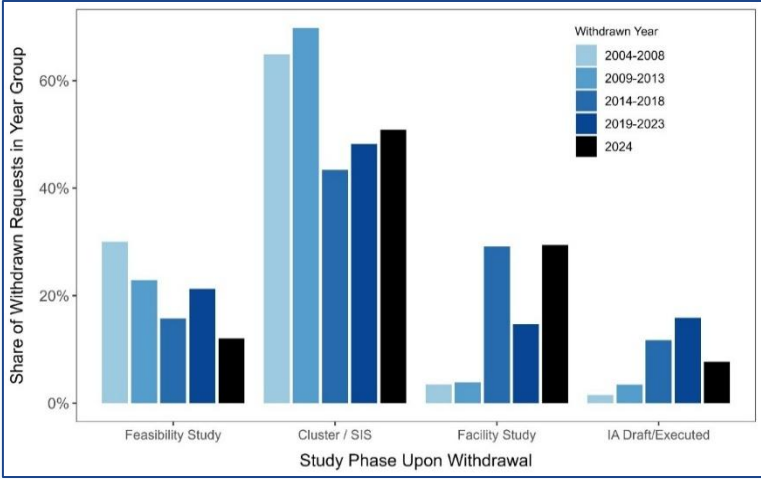
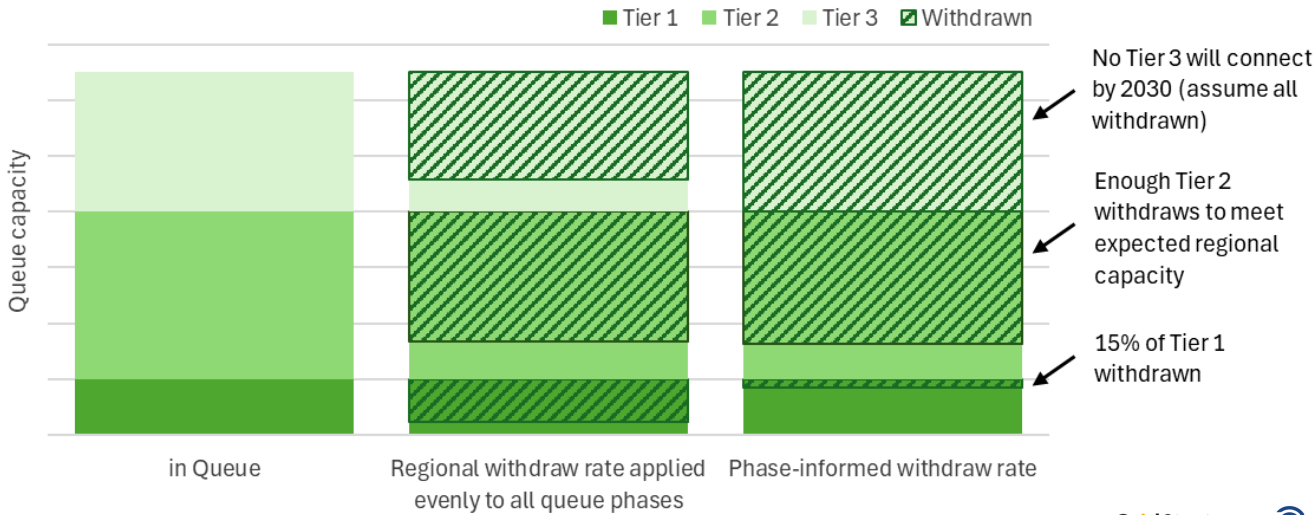


Illustration of two different methods to apply regional withdraw rates to interconnection queue data. The same amount of generation capacity withdraws in both methods.



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

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 DL0L	Summer & winter values. Battery resource uses storage (blended) and storage hybrid uses pumped storage DL0L. 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.

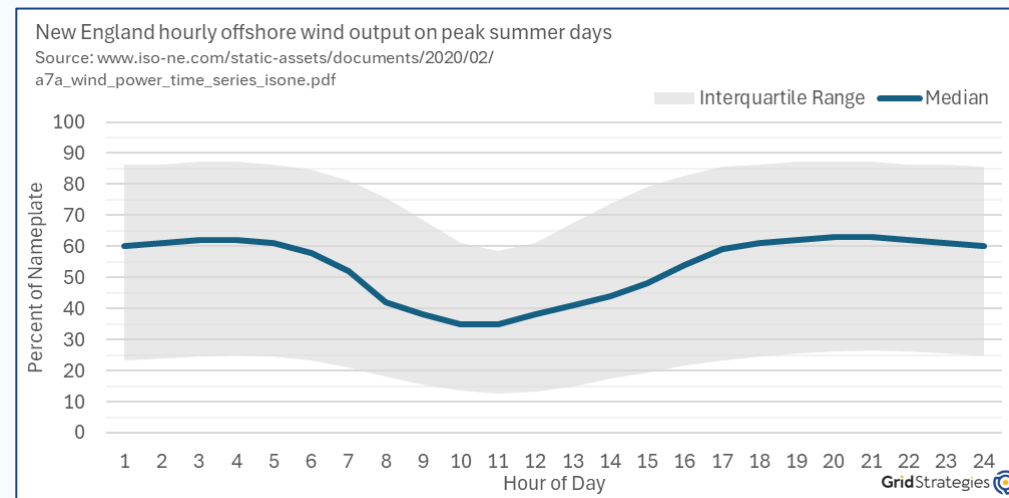
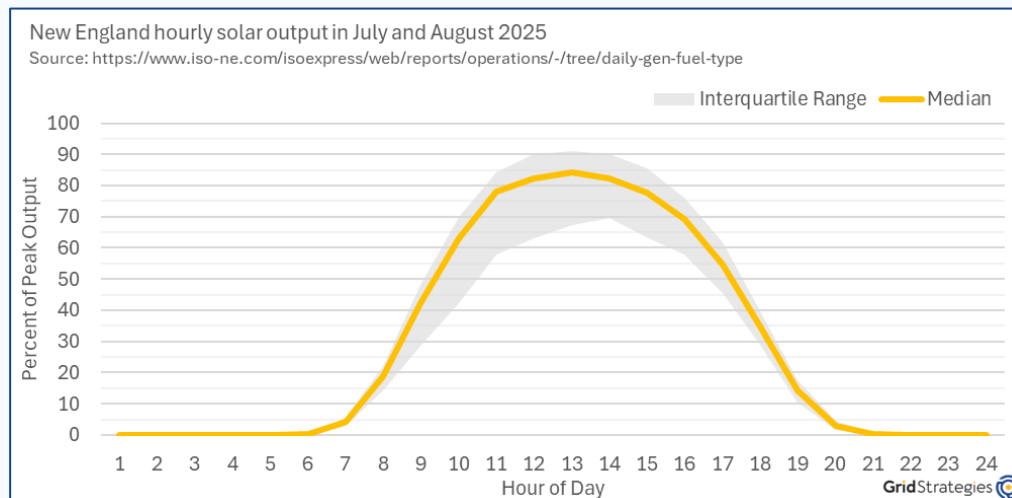
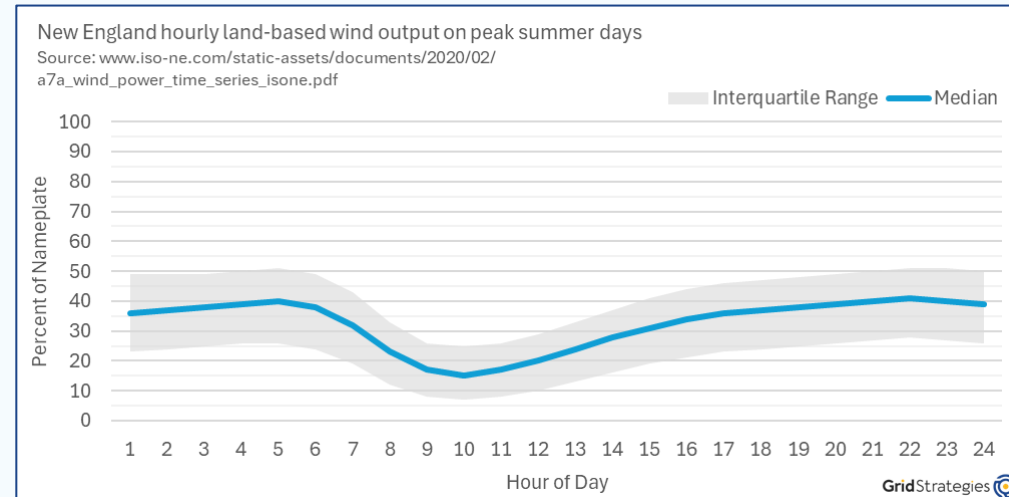
Analysis using LBNL data: New England wind and solar production

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.



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.

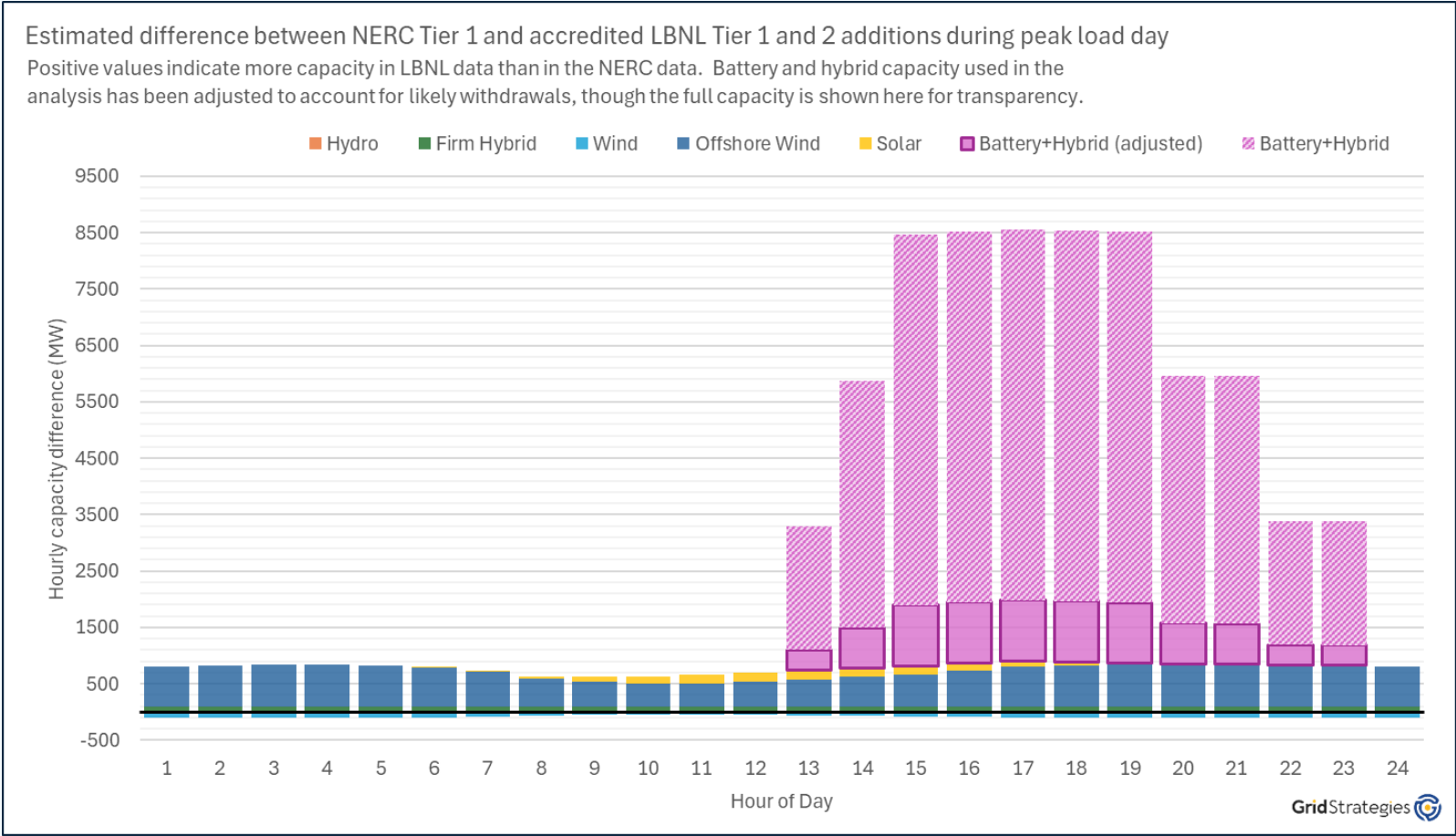


EXHIBIT 131-7

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.

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



Elaine Hart, Sylvan Energy Analytics
Washington UTC and Department of Commerce
Resource Adequacy Meeting
June 22nd, 2026

This work was sponsored by



Who we are



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 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

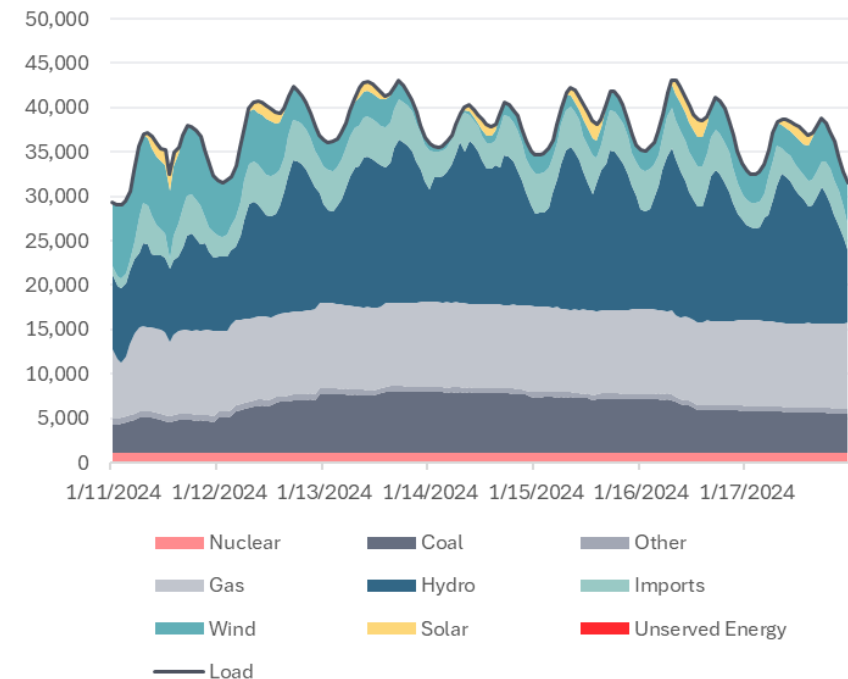
Independent evaluation approach

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

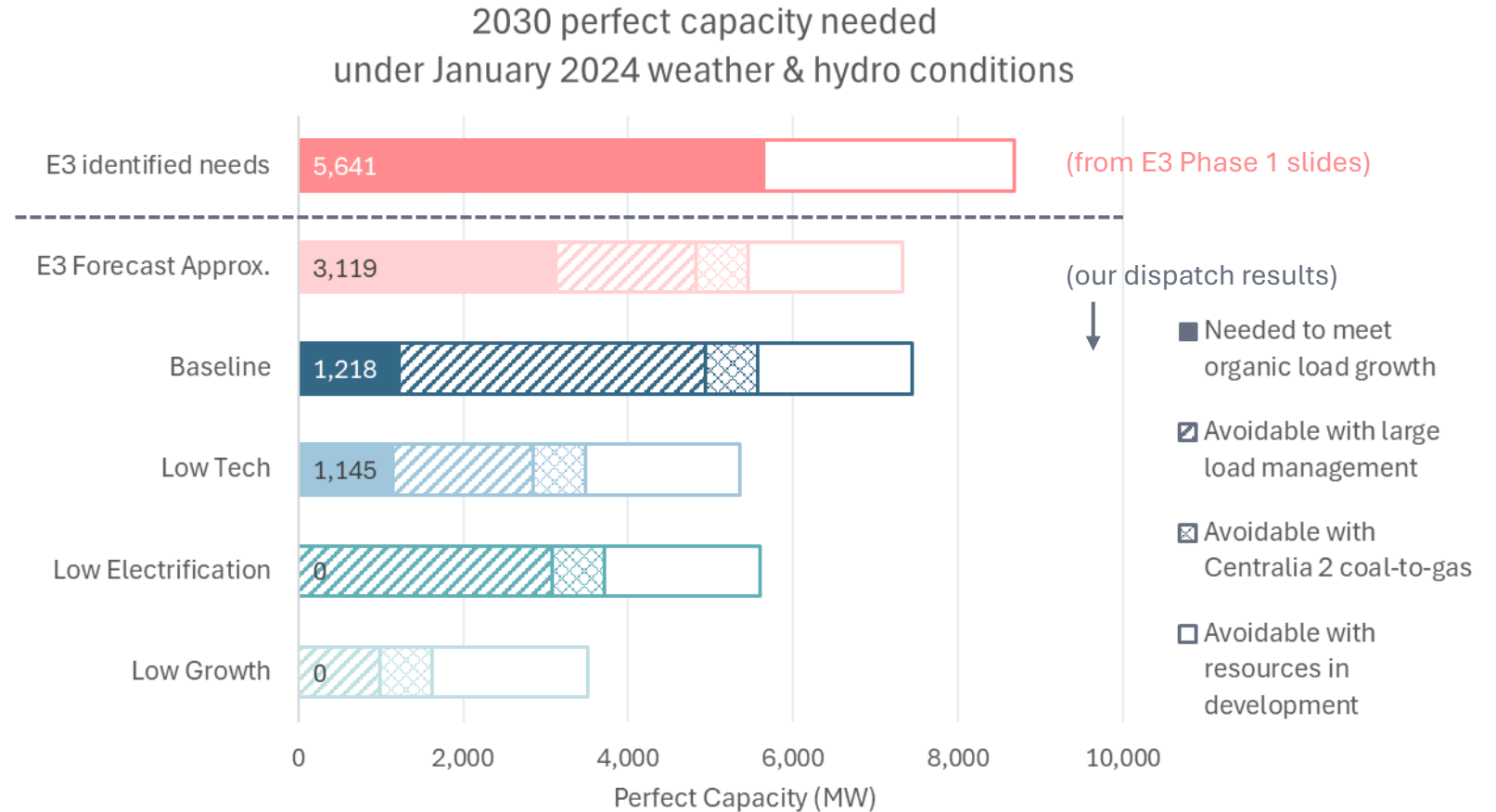
We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

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%
<i>Historical growth in electricity sales (2019-2024, excluding 2020)</i>			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

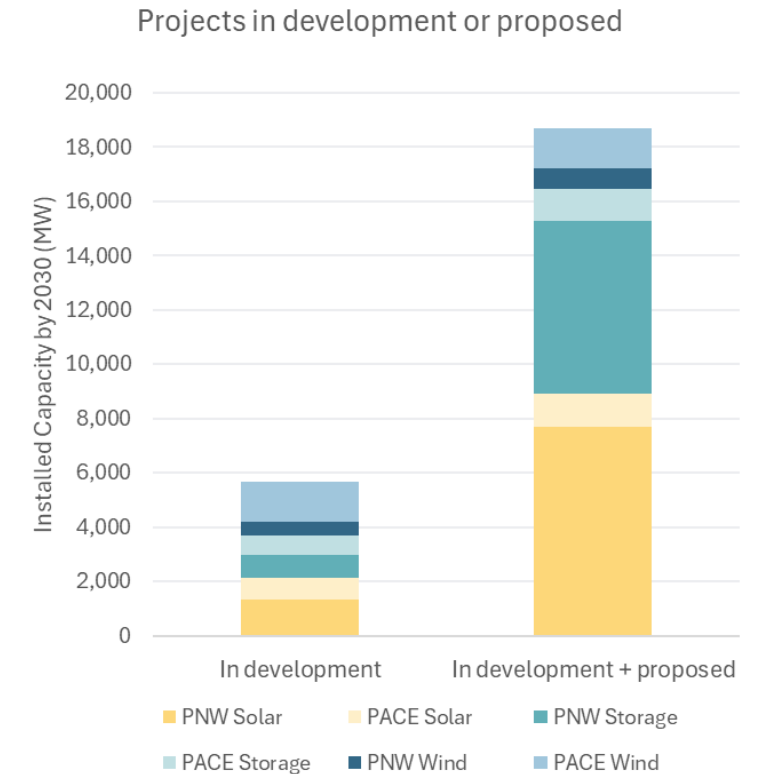


Winter portfolio ELCCs of new clean resources

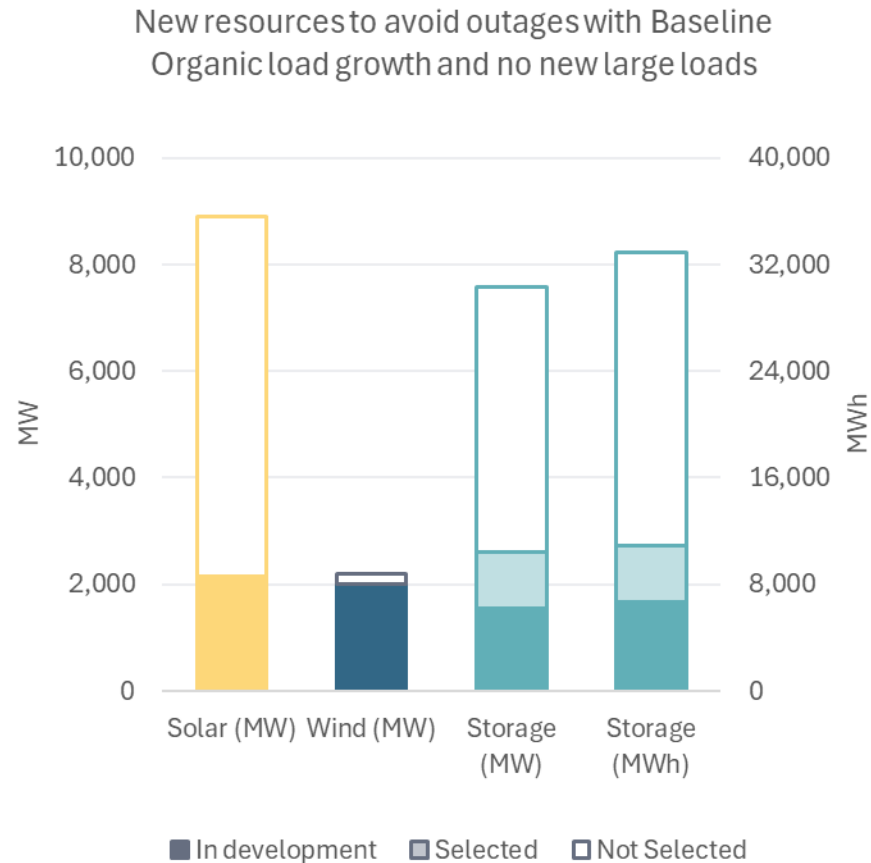
Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

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%

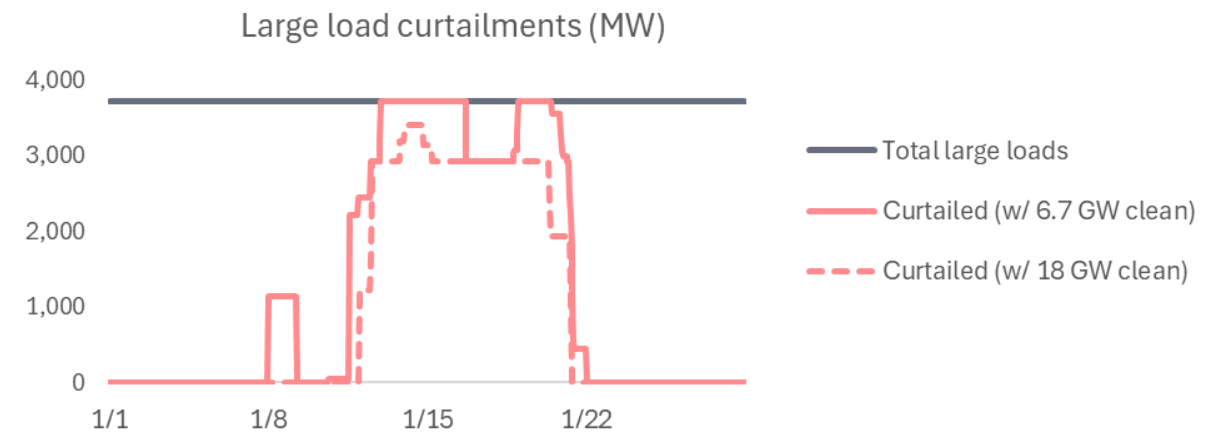
(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)



Clean resource additions and large load management in the Baseline scenario

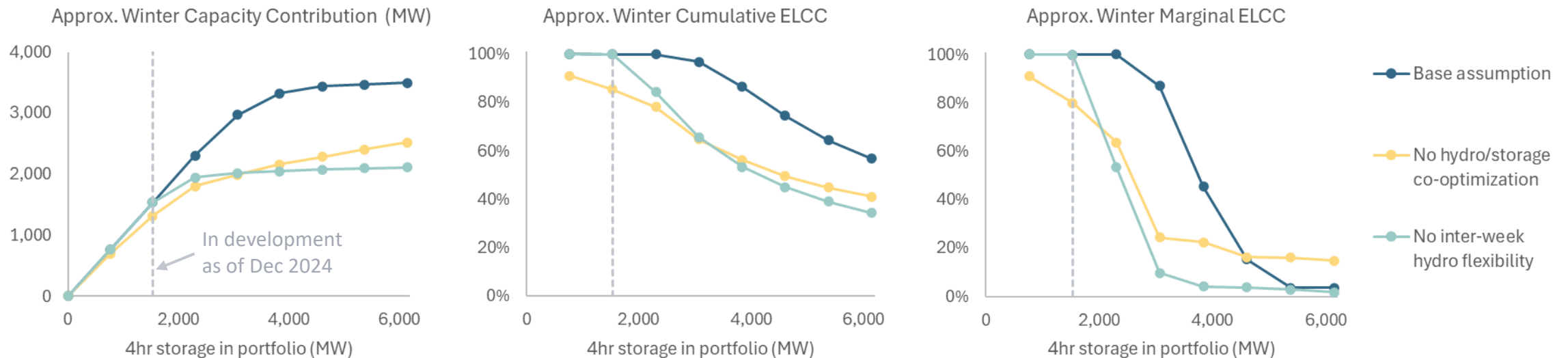


- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- Developing additional clean resources, even in very large quantities, only marginally reduces data center curtailments due to energy constraints



Winter ELCCs of 4hr storage

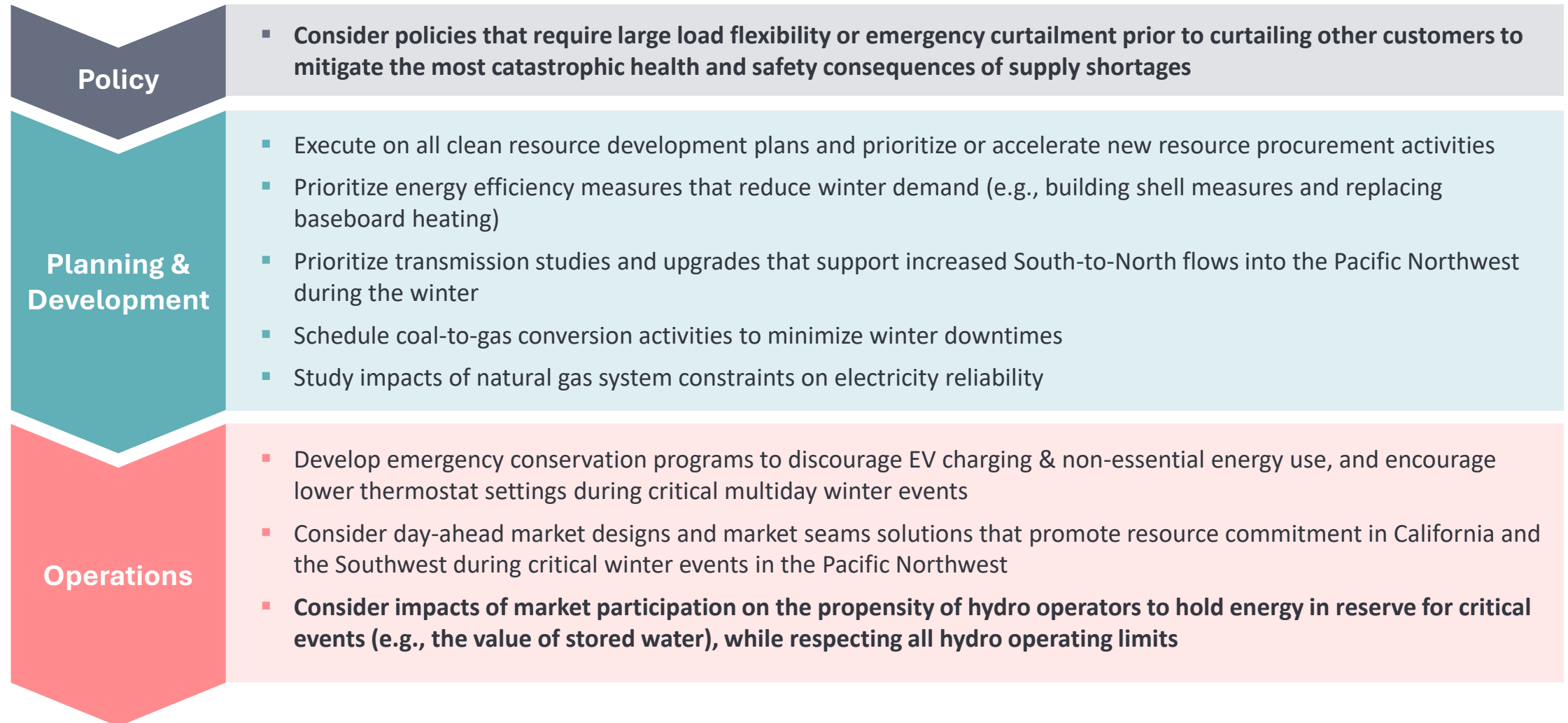
- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
 - Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
 - 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





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

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.

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.

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).

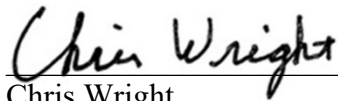
To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

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