BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-41:
Inst. Pol'y Integrity Report

Enough Energy

A Review of DOE's Resource Adequacy Methodology

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1: Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

[1] Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

[2] U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.
- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.
- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.*, N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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118 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

119 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

120 *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

121 Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

183 *See id.* at 9, 17.
184 *Id.* at 18, 12, A-1 (emphasis added).
185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.
186 *Id.* at 17–24.
187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).
188 *Id.* at 15522.
189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.

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Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-42:
GridLab Report

GridLab Analysis: Department of Energy Resource Adequacy Report

Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026** the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S.

Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

Previous post
London Calling: How UK Grid Innovation ...

Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-43:
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

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Citation

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https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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Nicholas Institute for Energy, Environment & Sustainability

The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

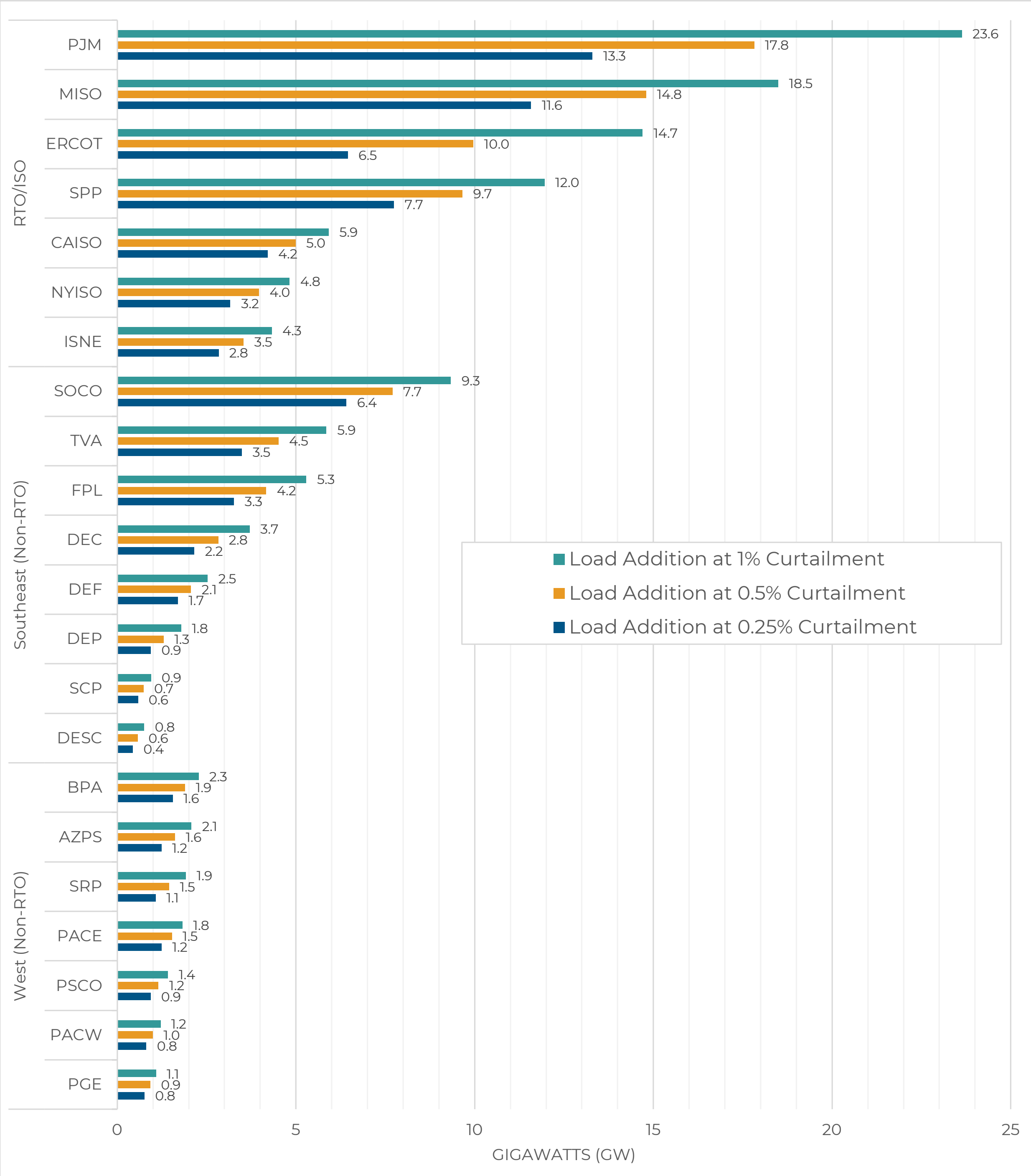
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

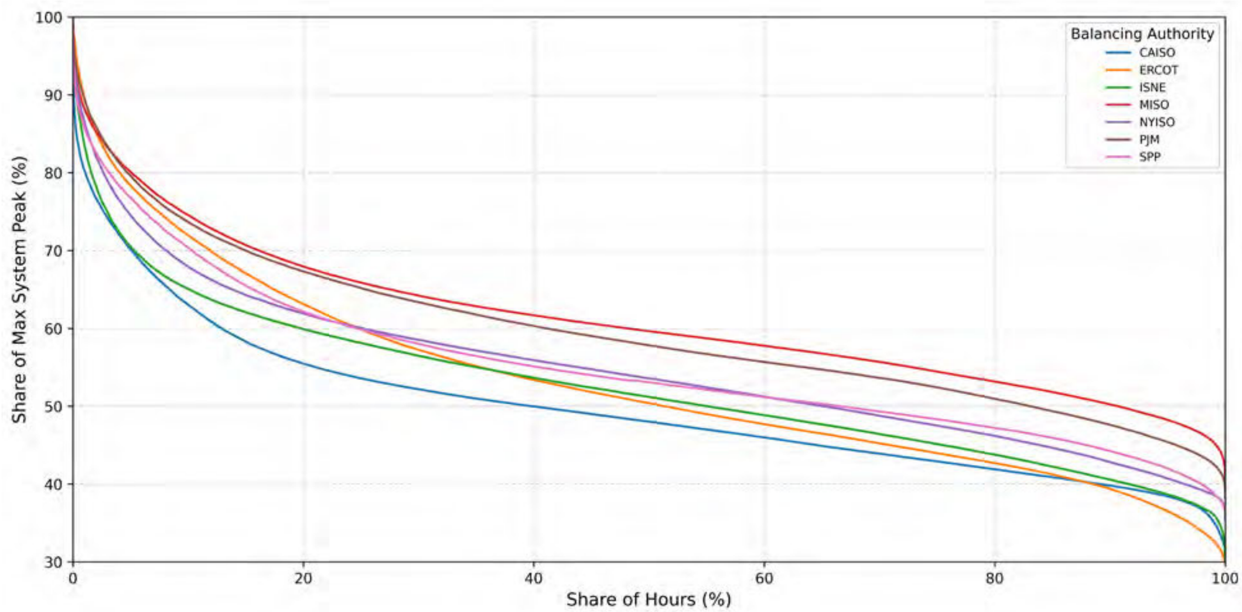
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

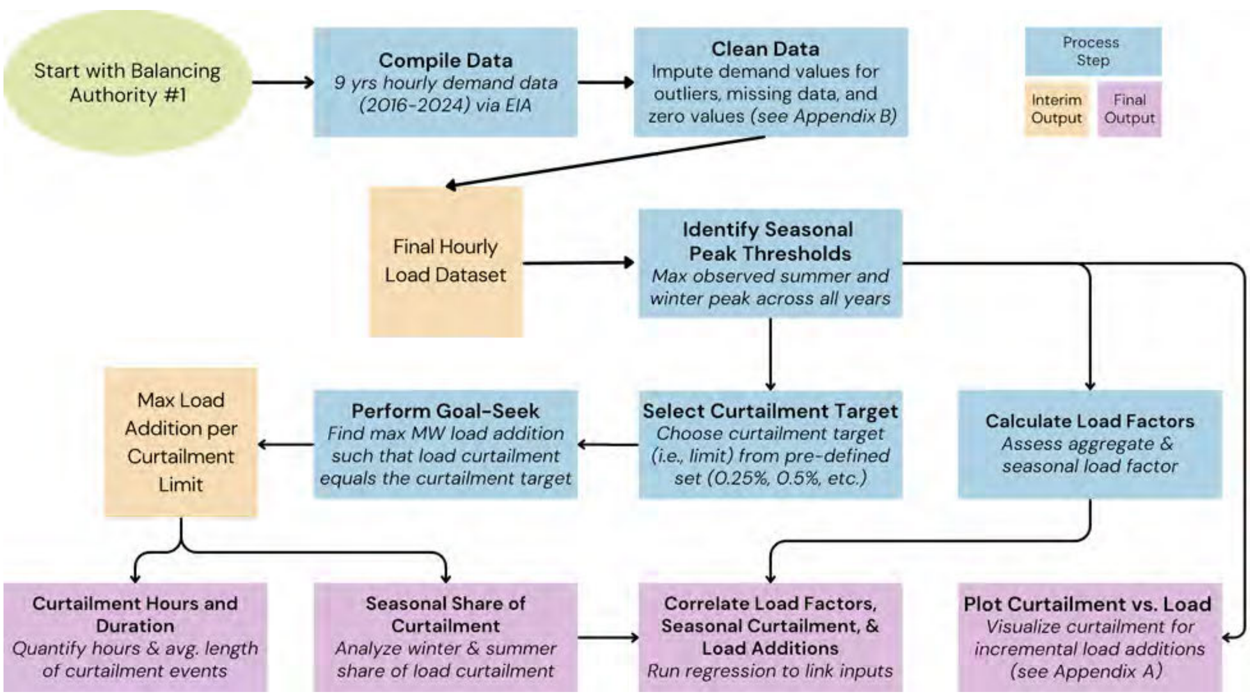
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

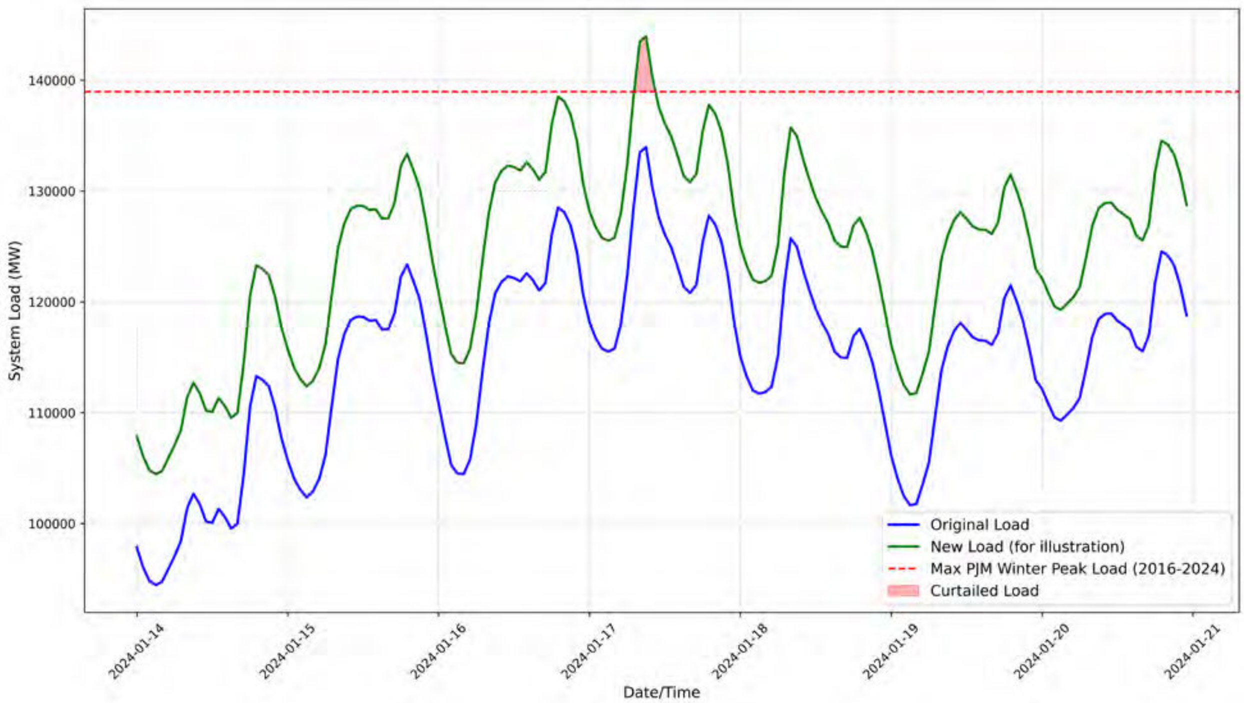
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

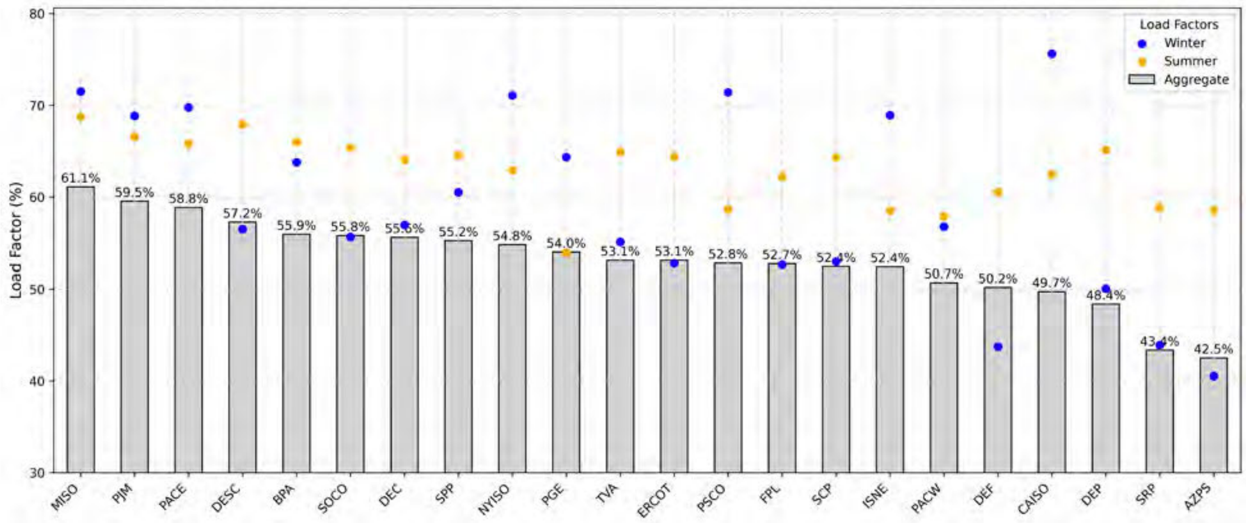
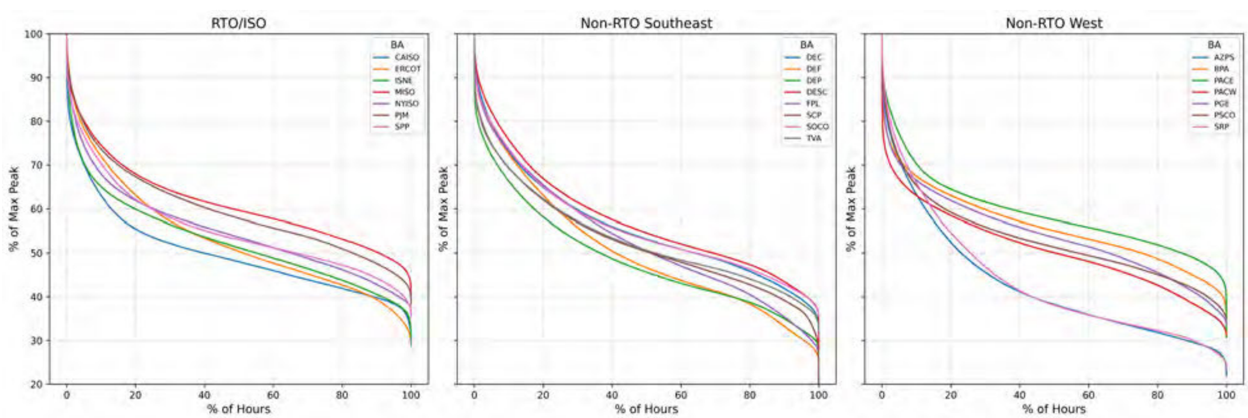


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

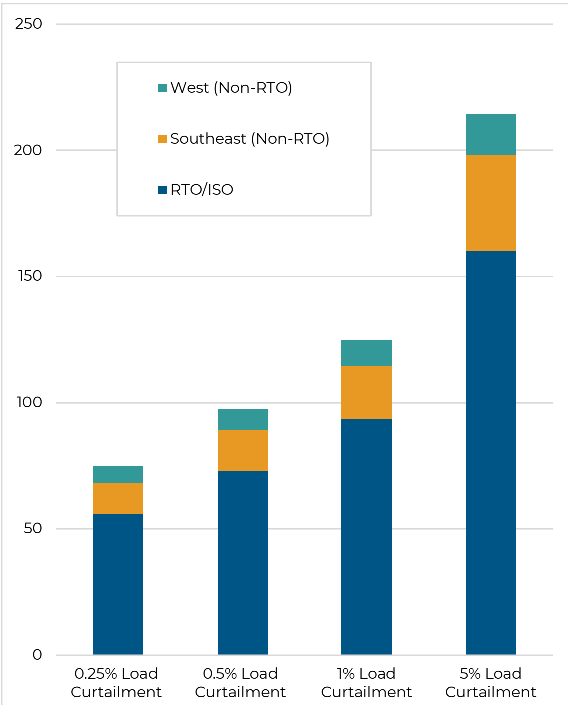


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

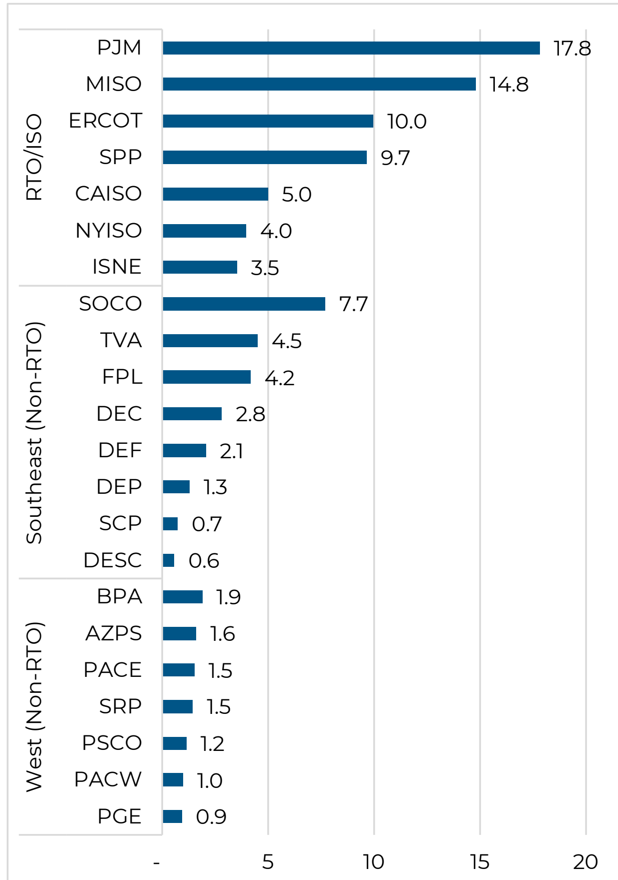
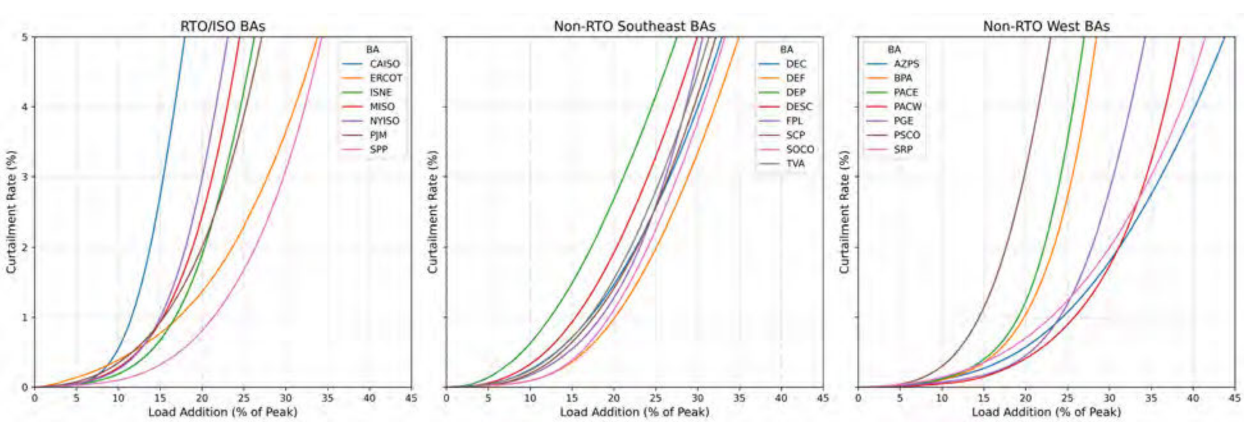


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

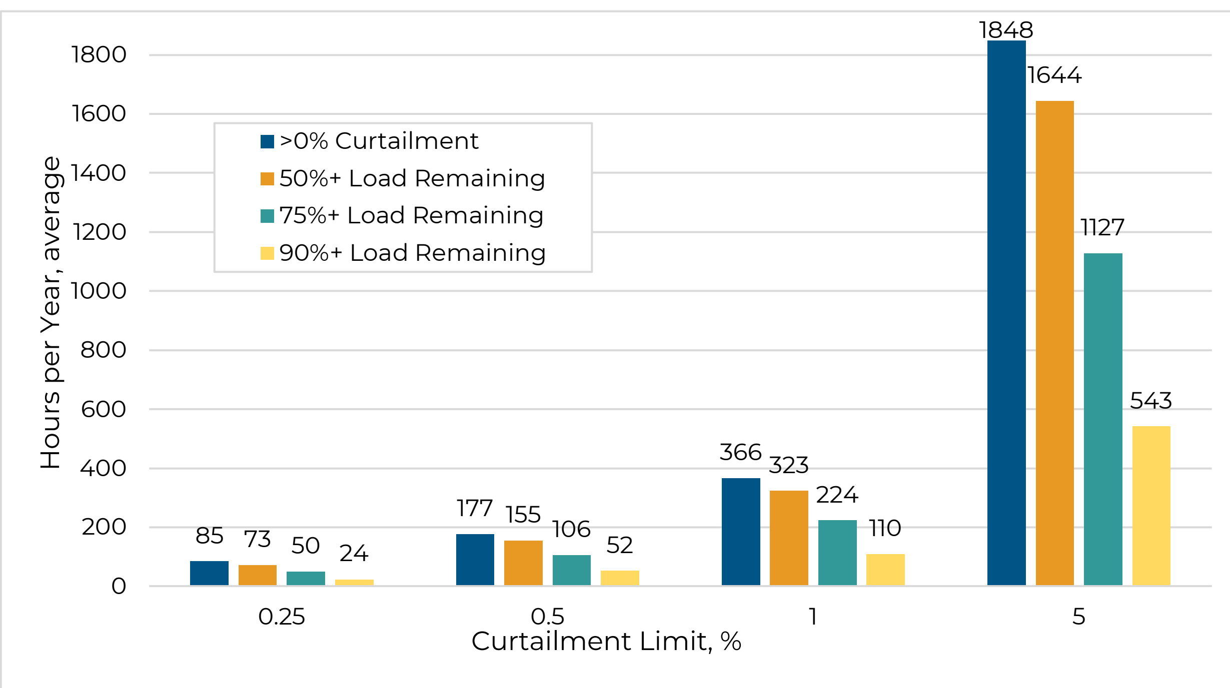
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

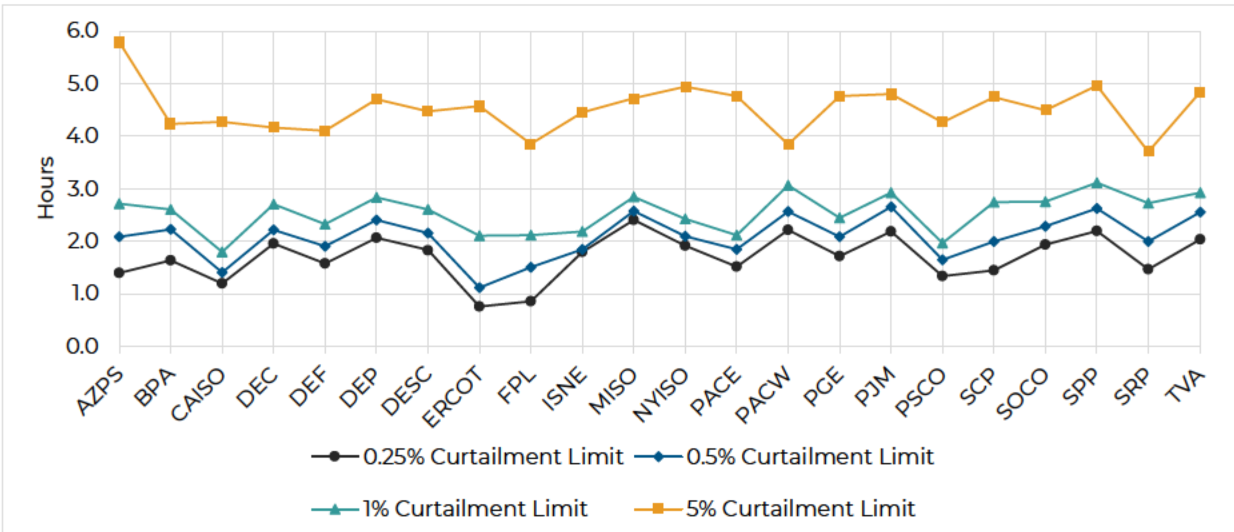
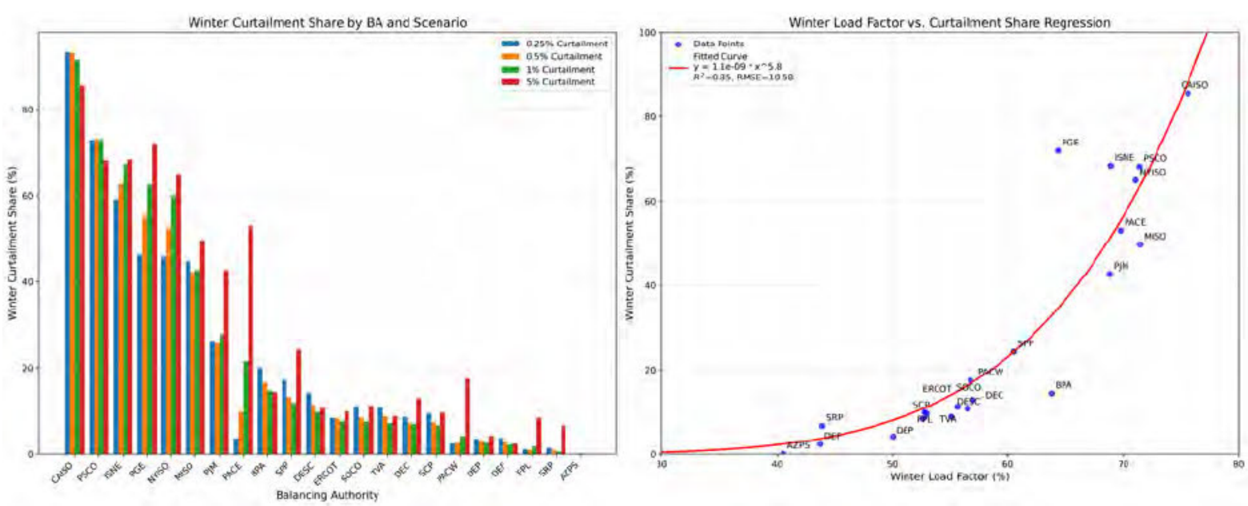


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

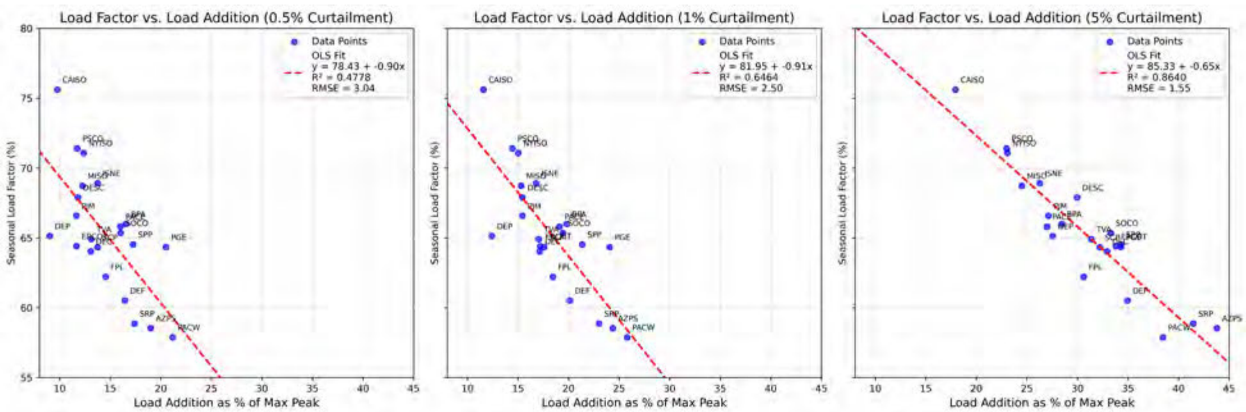
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably, this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

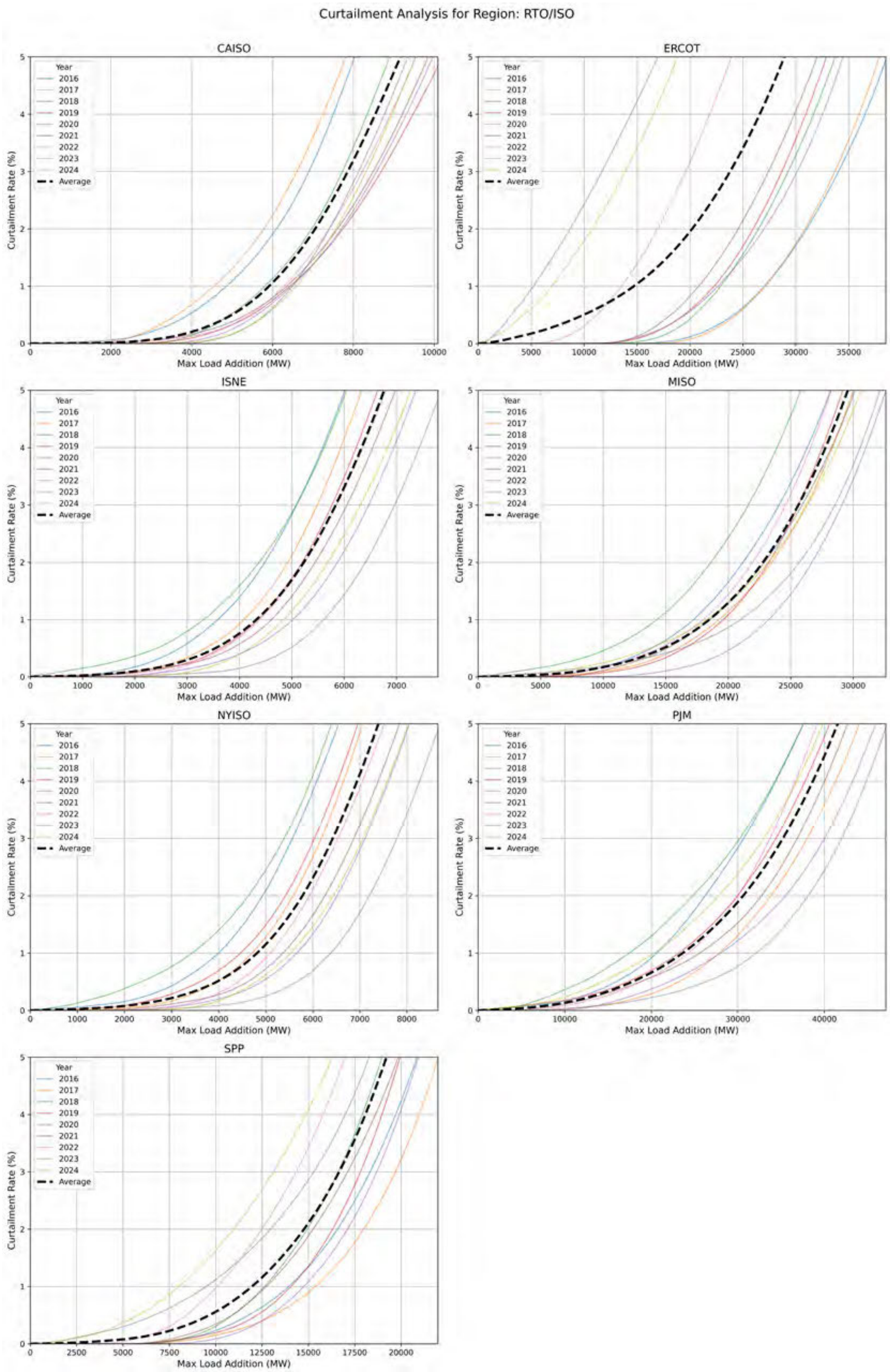


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

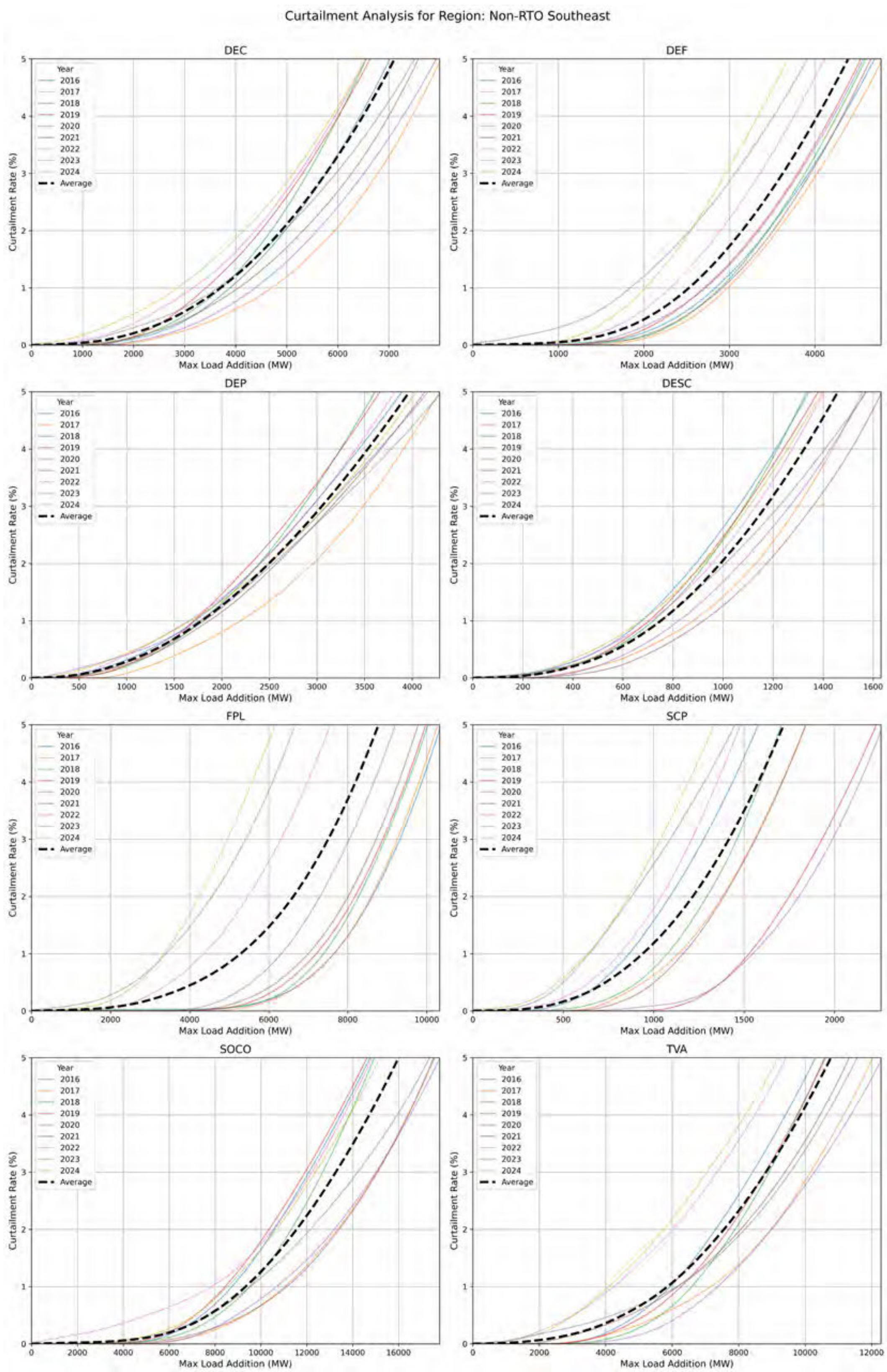
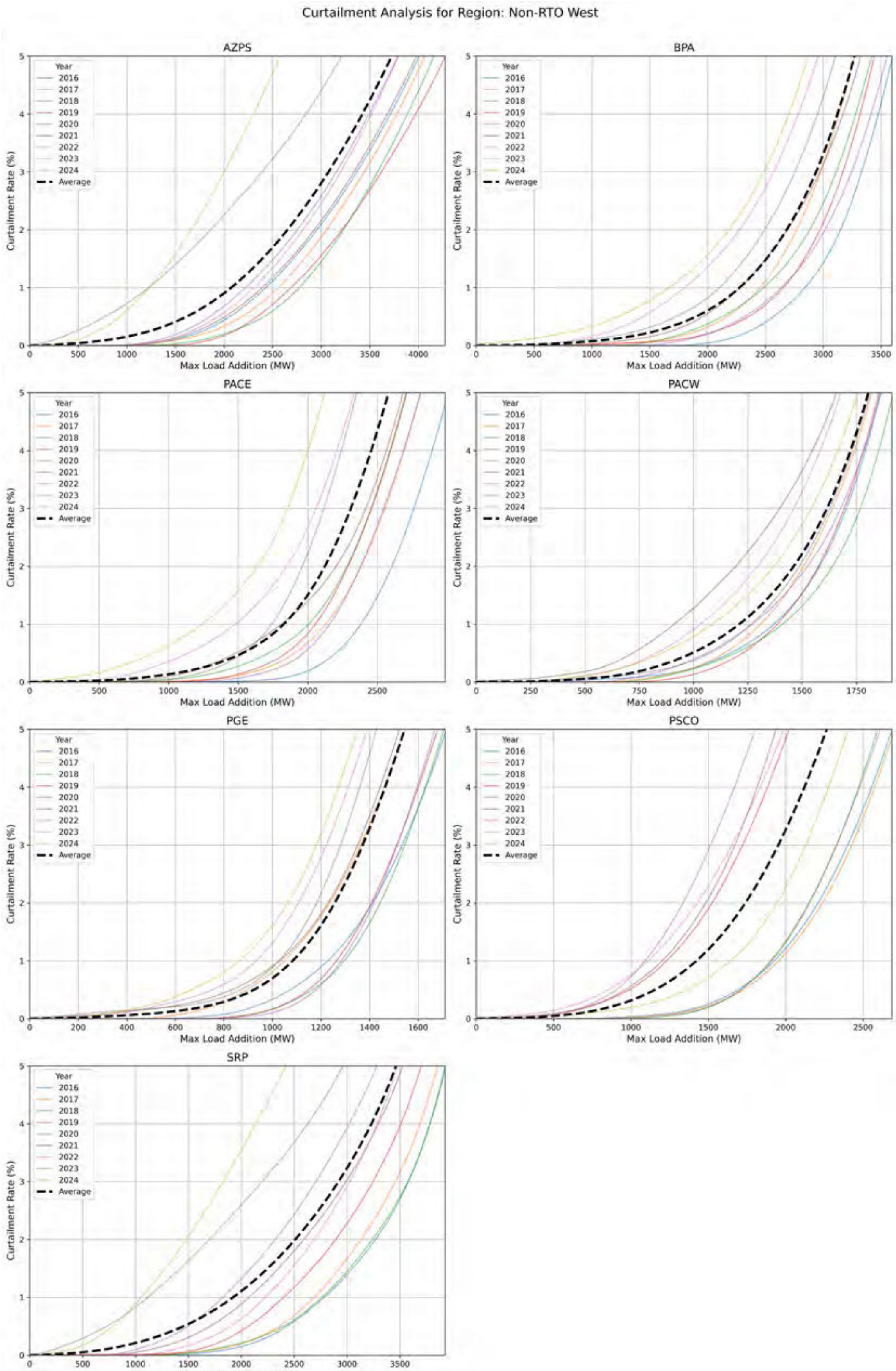


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization

   - **Dates:** Date-time formats were verified to be uniform.
   - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
   - **BA labels:** Labels were mapped to align with widely used acronyms, including:
     - CPLE → DEP
     - DUK → DEC
     - SC → SCP
     - SWPP → SPP
     - SCEG → DESC
     - FPC → DEF
     - CISO → CAISO
     - BPAT → BPA
     - NYIS → NYISO
     - ERCO → ERCOT

2. Identifying and handling outliers

   - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
   - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
   - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
   - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.

3. **Data validation**:

   - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
   - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L\,\cdot\,8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t\,\in\,T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t\,\in\,T_y}\max(0, Demand_t + L - Threshold_t)}{L\,\cdot\,8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-44:
RMI Analysis of Coal Plants' Threats to Reliability

Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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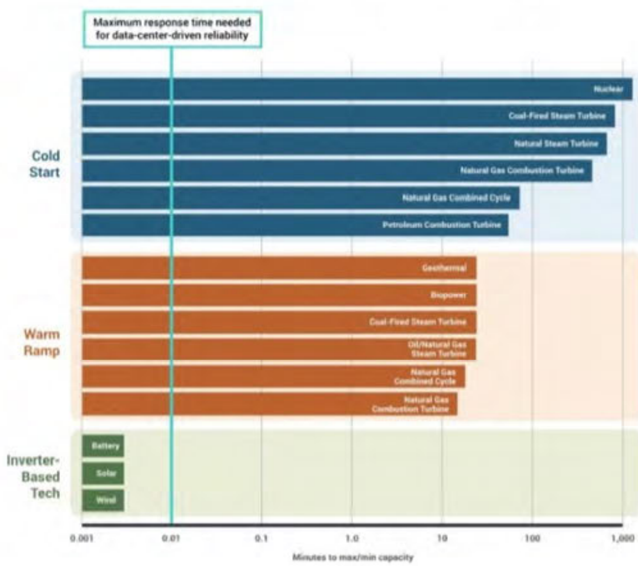
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

RECOMMENDED READING

Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

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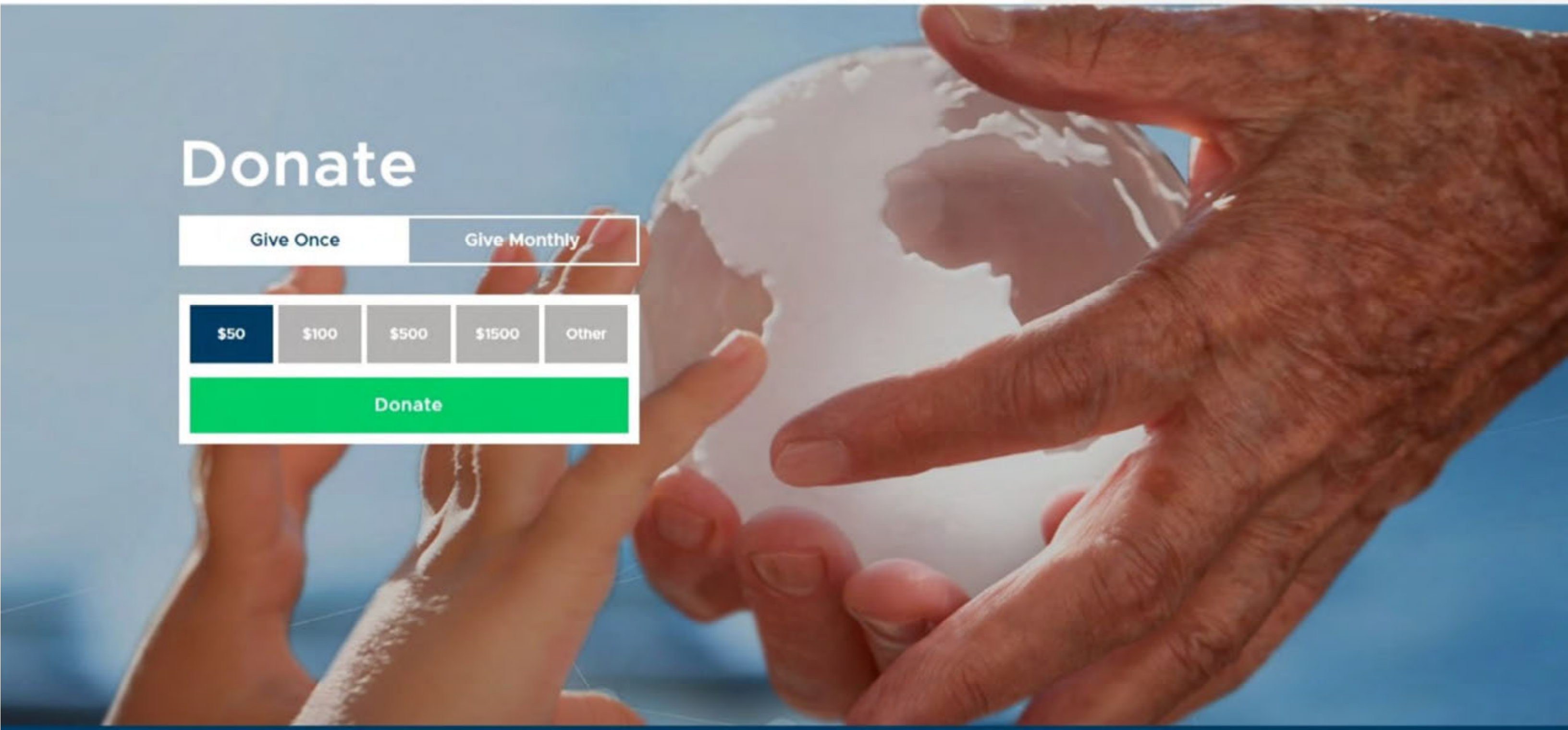

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-45:
Energy Innovation Report

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

ACKNOWLEDGEMENTS:

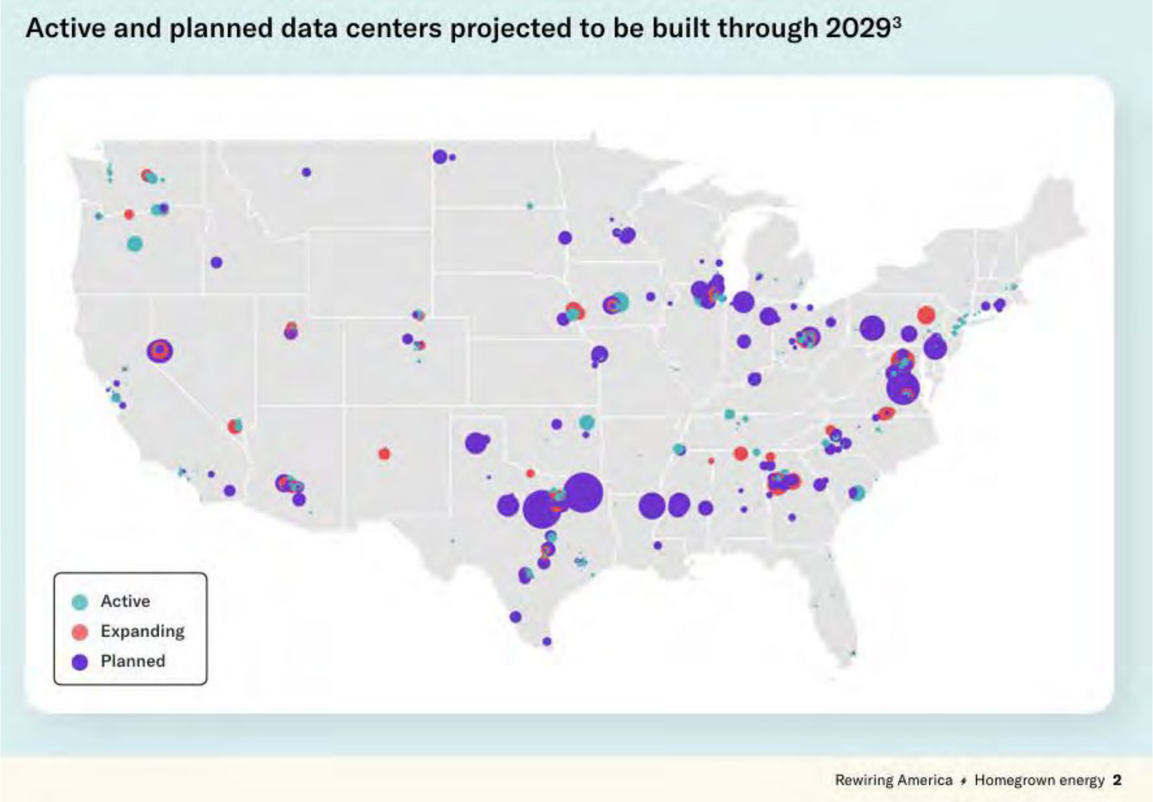
I would like to thank my Energy Innovation colleagues for their patient review and feedback on various drafts of this report. I would also like to acknowledge the Energy Systems Integration Group for their conferences, taskforce meetings, and webinars which helped me get started on my research.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

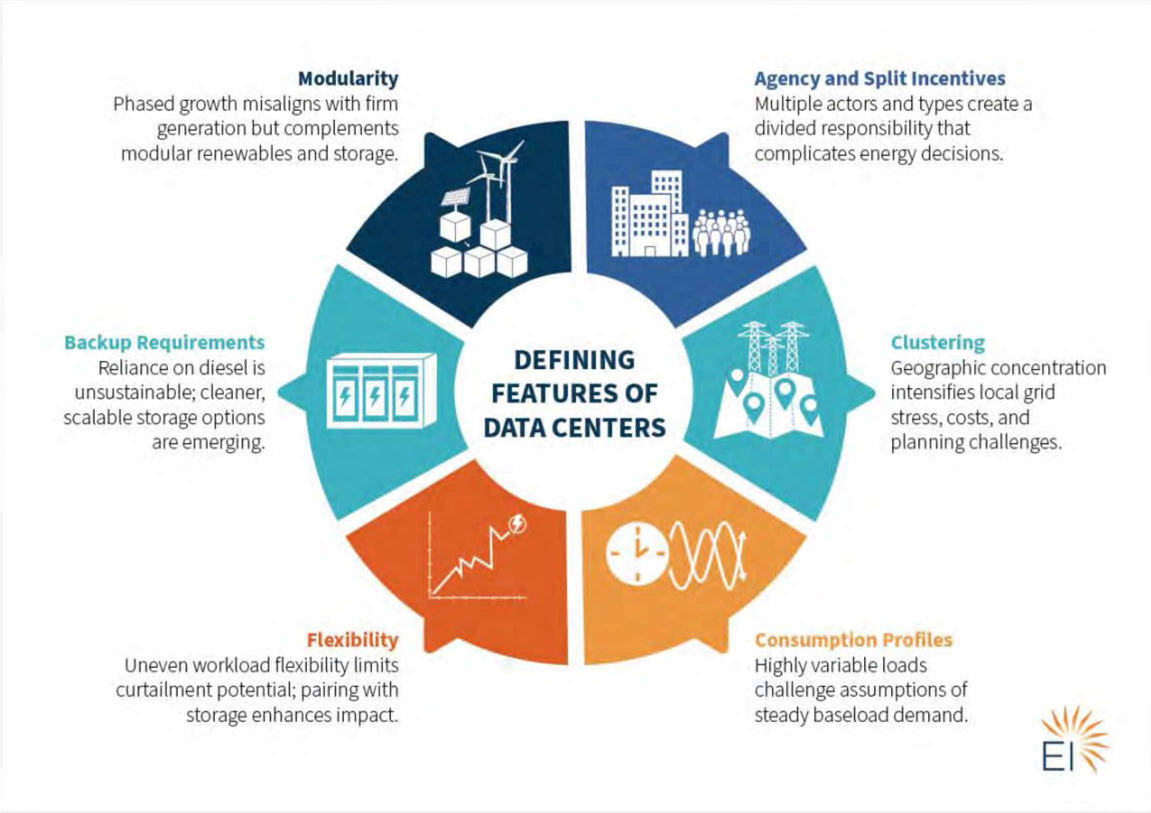
What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

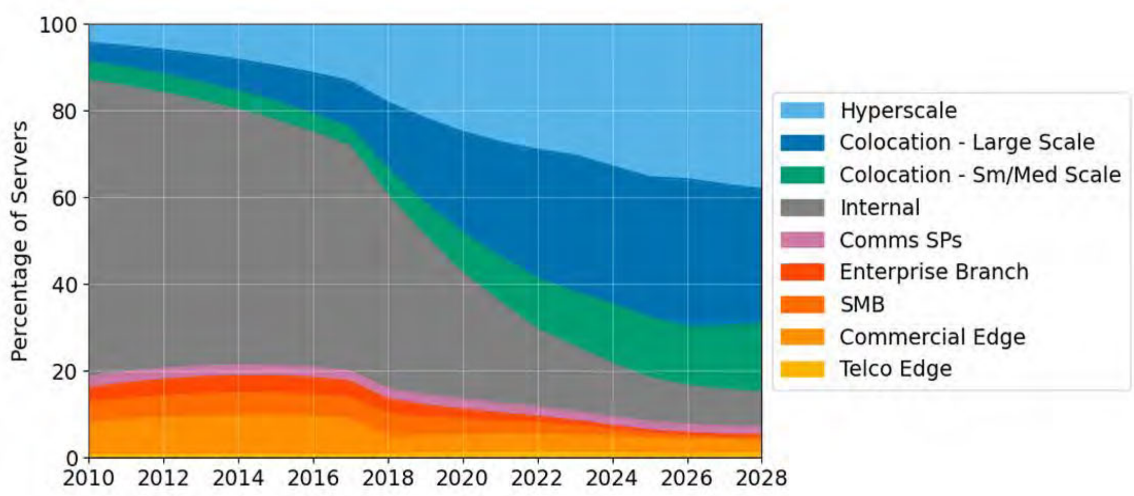


Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

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[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

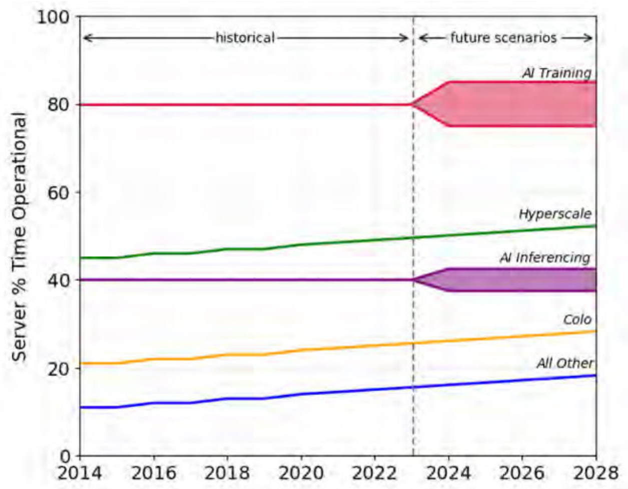
[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up *close*, *it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality*.

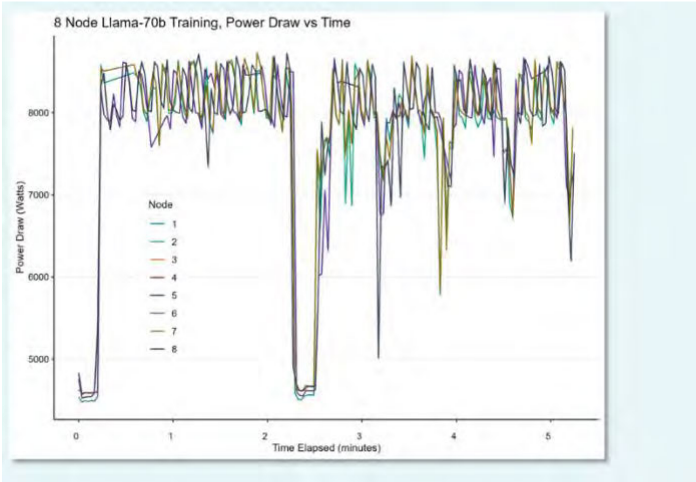
Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.

[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery[25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report [32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

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[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

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[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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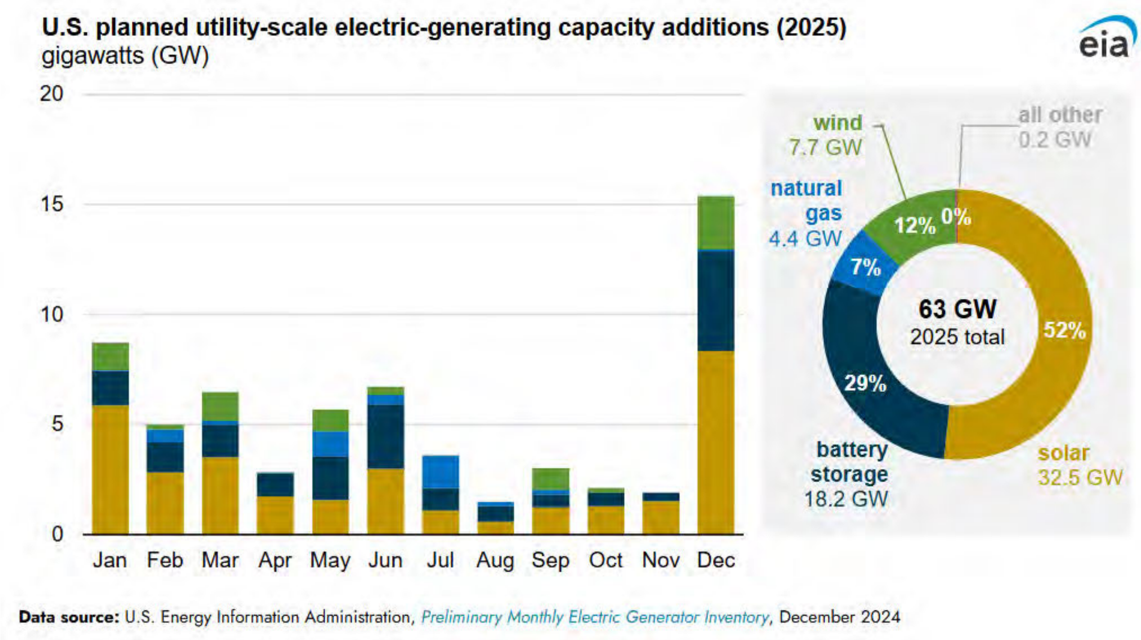
In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called “bridge power”[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[59][60]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

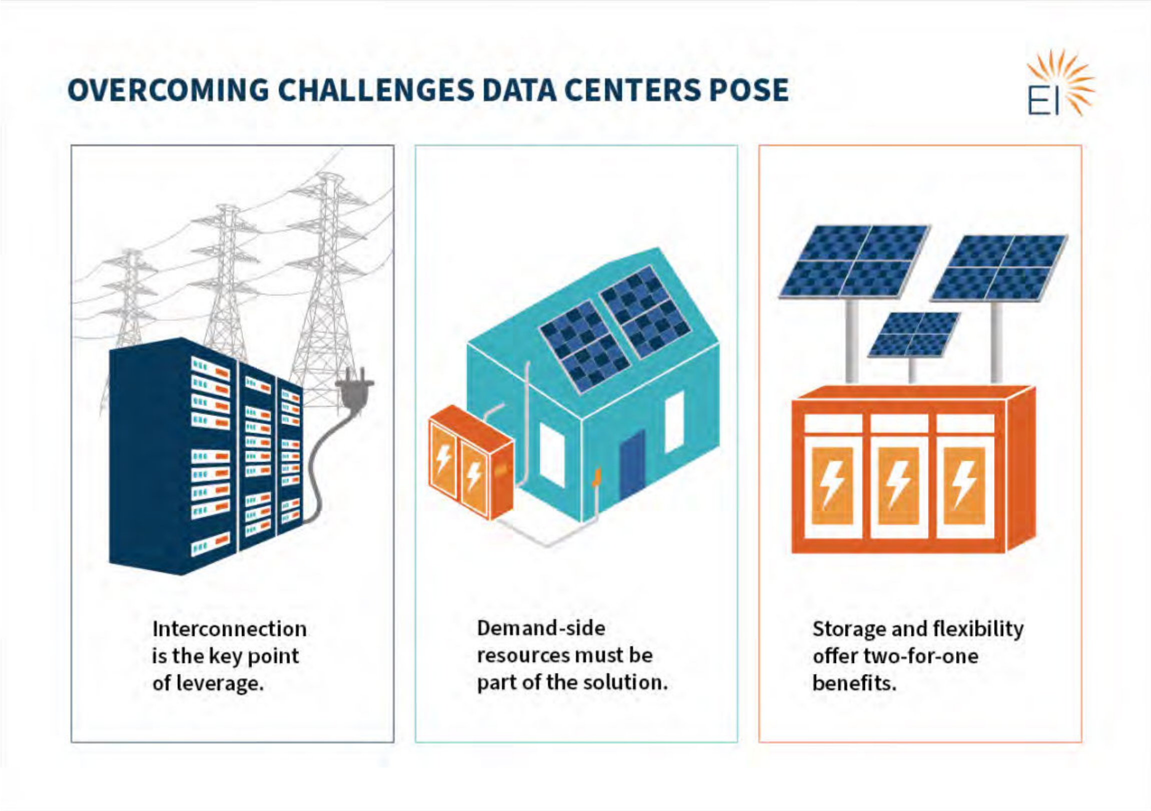
Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-46:
R Street Institute Commentary: *DOE "Zombies" Are Eating Competitive Power Mark*

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

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Exhibit 1-47:
Palgrave Handbook

The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

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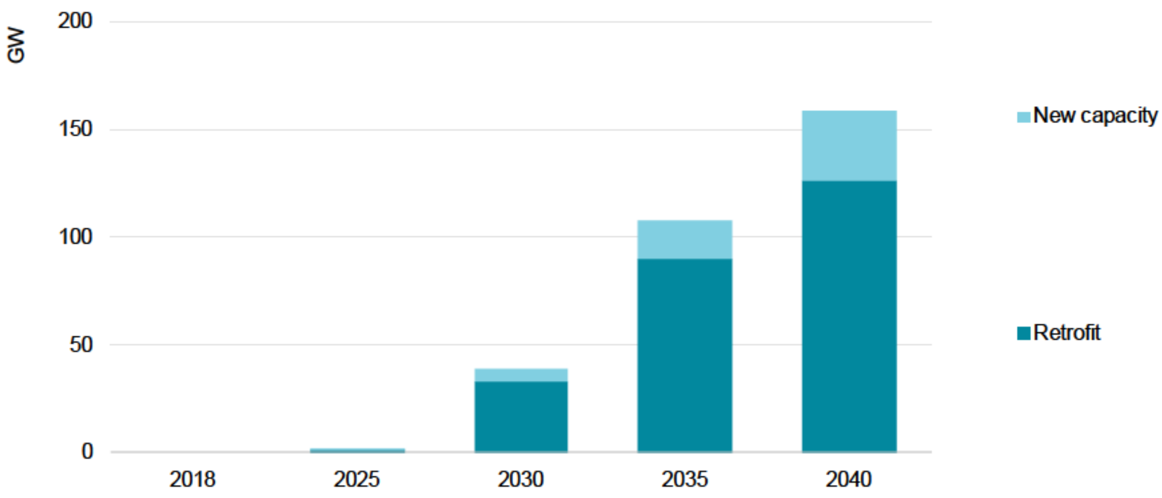
Exhibit 1-48:
IEA Report

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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Exhibit 1-49:
2011 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: TransAlta Centralia Generation LLC	]]]]]	 FIRST REVISION: ORDER NO. 6426

TO: Mr. Bob Nelson,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of 2 identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Use of selective noncatalytic reduction (SNCR) for nitrogen oxides control.
   b. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).
   c. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025. The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the units.
b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction for Nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides Emissions

1.1. Starting no later than the dates in Condition 1.1.1 and 1.1.2, emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited to a maximum of:

1.1.1. From the date of issuance of this Order, until 30 operating days after December 31, 2012, the nitrogen oxides emission limitation is 0.24 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.2. Beginning on the 31st operating day after December 31, 2012, the nitrogen oxides emission limitation is 0.21 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.3. The 30 day rolling average will be determined per Condition 7.

1.2. Beginning January 1, 2013, injection of ammonia or urea to control nitrogen oxides from a specific boiler must:

1.2.1. Commence when the flue gas at the point(s) of injection in the boiler has reached the minimum SNCR operating temperature as identified by the system vendor in the system specific operation manual.

1.2.2. End no sooner than the time coal is no longer introduced to the furnace of the boiler or the flue gas temperature at the injection point(s) is below the minimum SNCR operating temperature.

1.3. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

1.4. Coal used is required to be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

1.5. Nitrogen oxides emission reduction through the use of SNCR will be optimized as required in Condition 5. At the conclusion of the SNCR optimization study, the nitrogen oxides emission limitation contained in Condition 1.1.2 may be revised based on the results of the SNCR optimization study.

2. Ammonia emissions

2.1. Starting no later than the date in Condition 2.2, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. Starting on January 1, 2013, the ammonia emission limitation is 10 parts per million, dry volume (ppmdv) 30 operating day rolling average, both units averaged together.
EXCEPTION: During the portion of the optimization study directed by Condition 5.2.3.1, the ammonia emission limitation is 20 ppmdv daily average, both units averaged together.

2.1.2. In the event that during a given day, only one unit operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. Determination of compliance with the 30 operating day rolling average for ammonia will commence at midnight on the end of the 30th operating day after January 1, 2013.

2.3. Ammonia emission resulting from the use of SNCR will be optimized as required in Condition 5. The ammonia emission limitation contained in Condition 2.1.1 may be revised based on the results of the SNCR optimization study.

Schedule for Compliance

3. Compliance with the 30 operating day rolling average nitrogen oxides limitations begin on the dates given in Condition 1.1.1 and 1.1.2. Compliance with the 30 operating day rolling average ammonia emission limitations begins on the date given in Condition 2.1.

4. Coal units BW21 and BW22 will permanently cease burning coal and be decommissioned as follows:

4.1. One coal fired unit must permanently cease burning coal no later than December 31, 2020.

4.2. The second coal fired unit must permanently cease burning coal no later than December 31, 2025.

4.3. Conditions 4.1 and 4.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

Nitrogen Oxides and Ammonia Reduction Optimization

5. The operation of the selective noncatalytic reduction (SNCR) system for control of nitrogen oxides will be optimized to produce both the lowest nitrogen oxides emission rate and the lowest ammonia emission concentration possible at the same time.

5.1. The nitrogen oxides control system will be optimized to achieve both the lowest 30 operating day average pound nitrogen oxides/MMBtu emission rate and the lowest 30 day average concentration of ammonia in the flue gas that is reasonably achievable without significant adverse effect on mercury capture, boiler cleaning processes (aka soot blowing) or byproduct salability .

5.2. To achieve the goal of Condition 5.1, The owner of the Centralia Power Plant will:

5.2.1. Develop an SNCR optimization plan and submit it by April 30, 2013 to Ecology and the SWCAA for their joint review and acceptance.

5.2.1.1. A draft optimization plan will be submitted to Ecology and SWCAA by January 30, 2013 for their review and comment. Ecology and/or SWACAA will respond with written comments within 45 days of receipt of the draft optimization plan. If a request for a copy of this draft optimization plan is received, the agency receiving the request will provide the requester a copy of the draft optimization plan.

5.2.1.2. TransAlta will submit a final optimization plan reflecting all comments provided by Ecology and SWCAA. The plan must be submitted no later than April 30, 2013. The plan will be deemed to be accepted and the owner will immediately implement the plan if Ecology and/or SWCAA do not respond by May 30, 2013. If TransAlta, Ecology, or SWCAA receive a request for a copy of the final optimization plan, the entity receiving the request will provide a copy of the optimization plan to the requestor.

5.2.2. The optimization plan will:

5.2.2.1. Provide for all optimization testing to be complete and a report on the findings submitted to Ecology and SWCAA not later than December 31, 2014.

5.2.2.2. Identify the start and end dates of the optimization study.

5.2.2.3. Describe the optimization process to be followed, including:

5.2.2.3.1. The overall schedule.

5.2.2.3.2. The specific dates for each stage of the optimization program, especially the start and end dates of the testing to determine how low of a nitrogen oxides emission rate can be achieved per condition 5.2.3.1.

5.2.2.3.3. Whether testing will be done on only one boiler at a time or both together.

5.2.2.4. Identify acceptable maximum ammonia content of fly ash used for cement and gypsum used to produce wallboard, including the basis for those maximums.

5.2.2.5. Identify all additional flue gas monitoring that will be used to determine optimum urea or ammonia injection rates for maximum nitrogen oxides reduction.

5.2.2.6. Evaluate the effect of ammonia injection on mercury capture effectiveness, fly ash ammonia content, and gypsum product ammonia content. This includes a description of the sampling and analysis processes.

5.2.3. The focus of the optimization plan, is to determine :

5.2.3.1. The maximum nitrogen oxides reduction possible with an ammonia emission rate of up to 20 ppmdv, daily average, each unit individually;

5.2.3.2. The maximum nitrogen oxides reduction with which compliance can be reasonably achieved within an ammonia emission rate of 5 ppm; and

5.2.3.3. Determine the lowest nitrogen oxides emission rate reasonably achievable that coincides with the minimum ammonia emission rate.

5.2.3.4. The ability to achieve a nitrogen oxides emission rate of less than 0.19 lb/MMbtu, 30 operating day rolling average, each unit individually.

5.3. Ecology and SWCAA will review the optimization study report for 60 days. At the end of the 60 days the two agencies will either request TransAlta make changes to the report or accept the report in writing.

5.4. Within 90 days of receiving written acceptance of the optimization study report by Ecology and SWCAA, the plant operations and maintenance manual(s) will be amended to include the operating parameters reflecting the optimized ammonia or urea injection rates developed.

5.5. Revisions to this BART Order

5.5.1. Within 30 days of acceptance of the optimization study report by Ecology and SWCAA, TransAlta will submit a request to Ecology to revise the emission limits in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization.

5.5.2. Upon receipt of the request to revise the emission limits, or within 60 days of acceptance of the optimization report by Ecology and SWCAA, Ecology will proceed to revise the emission limitations in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization study. Other approval conditions, including this condition, may be revised based on the final emission limitations.

5.5.3. The nitrogen oxides limitation will not be raised above the level in Condition 1.1.2 as it existed on the date of issuance of this Revised Order.

5.5.4. The ammonia limitation will not be raised above the level in Condition 2.1.1 as it existed on the date of issuance of this Revised Order.

Monitoring and Recordkeeping Requirements

6. Ammonia:

6.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

6.1.1. Testing shall occur once each calendar quarter, with no consecutive tests less than 80 or more than 110 calendar days apart.

6.1.2. If 3 consecutive tests are each less than the ammonia limitation, then the testing frequency reduces to once every 6 calendar months, provided the nitrogen oxides emission limit is complied with during the test.

6.1.3. If, after there are 3 consecutive tests less than the ammonia limitation, the next 2 consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

6.1.4. If at any time there is a test showing emissions above the emission limitation, then the testing frequency reverts to quarterly until the requirements in Conditions 6.1.2 and 6.1.3 are met.

6.1.5. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

6.1.6. During the ammonia testing using BAAQMD Method ST1B (or CTM-027), the 30 rolling ammonia emission limit is to be treated as an hourly average for the purpose of Conditions 6.1. and 6.2.

6.2. For use as a routine indicator of compliance between the tests required in Condition 6.1, ammonia emissions will be estimated. The estimate will be based on a calculation which uses as inputs the reagent concentration and flow rate, a calculation or measurement of the uncontrolled nitrogen oxides rate, the continuous nitrogen oxides monitoring results measured in the stack, and other parameters as necessary.

6.3. At TransAlta's option, an ammonia continuous monitoring system may be used instead of periodic emissions tests. A continuous ammonia monitoring system used for compliance must meet the monitor location requirements contained in 40 CFR Part 60 Appendix B, Performance Specification 1 or 2, and the quality assurance and quality control requirements of 40 CFR Part 60 Appendix F as applicable.

7. Nitrogen oxides monitoring and averaging

7.1. For any hour in which coal is combusted in a unit, the owner/operator of each unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) from all operating units and dividing that by the sum of the hourly heat inputs in million Btu for all operating units. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler operating day and the previous 29 successive boiler operating days.

7.2.). An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

7.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

7.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

8. Ammonia emission limitation compliance based on periodic stack sampling and parameter monitoring.

8.1. Compliance with the ammonia emission limitation is demonstrated by meeting the limitation during the stack testing period. The average of the 3 discrete sampling runs will be used to determine compliance with the ammonia emission limitation until the next periodic stack testing occurs.

8.2. During each periodic stack test on each boiler, the ammonia or urea reagent injection rate and the ammonia to nitrogen oxides ratio for each sampling run shall be determined, recorded and reported as part of the testing report.

8.3. During plant operation between periodic stack testing, compliance with the ammonia emission limitation will be indicated by:

8.3.1. Injecting ammonia or urea reagent at the injection rate for ammonia or urea reagent used during the most recent stack sampling at the appropriate operating rate; and

8.3.2. Meeting the nitrogen oxides emission limit.

9. Coal Quality Monitoring

9.1. Coal nitrogen and sulfur content will be determined by taking a sample of the coal from the transfer belts between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

9.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample must be taken following ASTM Method D2234/D2234M-07.

9.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

9.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

10. A letter reporting of achievement of each compliance date in the schedule in Conditions 3 and 4 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

11. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 12. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

12. Emission monitoring data will be reported to Ecology and to the SWCAA.

12.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

12.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported in units of lb/MMBtu, utilizing at least 2 significant figures;

12.1.2. The cumulative short tons of nitrogen oxides per unit and combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

12.1.3. Periodic stack testing for ammonia emissions shall be submitted within 45 days of completion of the test.

If TransAlta elects to use continuous emission monitoring of ammonia instead of periodic stack testing, the quarterly report shall contain the 30 operating day rolling average ammonia concentration for both units averaged together for each operating day in the reporting period. Average ammonia concentrations shall be reported in units of ppmdv to 2 significant figures.

12.1.4 For each hour of boiler operation, the ammonia or urea injection rate in units of pounds of ammonia or urea/hour, , the boiler temperature at the point of injection, injection level in use, and the estimated ammonia emission concentration.

12.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end January 1, 2018.

13. Coal nitrogen and sulfur content information must be submitted to SWCAA and Ecology within 30 days of the end of each calendar quarter.

13.1. Coal nitrogen and sulfur reporting must include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the average sulfur and nitrogen concentrations for the calendar quarter, and the maximum and minimum concentrations found during the calendar quarter.

13.2. After June 30, 2011, the report will include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

13.2.1. The weekly coal sample test results will be retained for at least 5 years and available for review by Ecology or SWCAA upon request.

13.2.2. Coal quality reporting to Ecology will end the earlier of:

13.2.2.1. January 1, 2018, or
13.2.2.2. The decommissioning of either unit BW21 or BW22, or
13.2.2.3. The date monitoring of the quality of coal fired in units BW21 and BW22 is required by a regulation issued by EPA under the authority of Section 112 of the federal Clean Air Act.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board PO Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 4224–6th Avenue SE Rowe Six, Bldg 2 Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:		Deliver your appeal in person to:
Department of Ecology Appeals Coordinator PO Box 47608 Olympia, WA 98504-7608	OR	Department of Ecology Appeals Coordinator 300 Desmond Drive SE Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 13 day of Dec., 2011 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-50:
2020 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN	]	
ADMINISTRATIVE ORDER AGAINST:	]	
	]	SECOND REVISION:
TransAlta Centralia Generation LLC	]	ORDER NO. 6426
	]	

TO: Mr. Mickey Dreher TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of two identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Utilization of the selective non-catalytic reduction (SNCR) for nitrogen oxides control as appropriate.
   b. Low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

c. Utilization of the Combustion Optimization System with Neural Network on BW22 as appropriate.
d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025.

b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction (SCR) for nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides emissions

1.1. Emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited, from the date of issuance of this Order, to:

1.1.1. 0.21 lb/MMBtu on the unit that does not have the Combustion Optimization System with Neural Network installed. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.

1.1.2. 0.18 lb/MMBtu on the unit that does have the Combustion Optimization System with Neural Network. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.

1.1.3. 0.18 lb/MMBtu on the unit that continues coal fired power generation starting January 1, 2021.

1.2. The 30 day rolling average will be determined per Condition 5.

1.3. TransAlta may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NOx limit for BW21 and BW22 including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

2. Ammonia emissions

2.1. Starting no later than the effective date of this order, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. 10 parts per million, dry volume (ppmdv). This is a 30 operating day rolling average of both units averaged together.

2.1.2. In the event that during a given day, only one unit is operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. The injection rate of urea (as the source of ammonia) to meet the nitrogen oxides emission in Section 1.1.1 and 1.1.2 is solely determined by TransAlta.

Schedule for Compliance

3. Coal units BW21 and BW22 will permanently cease coal-fired power generation operations as follows:

3.1. One of the units must cease no later than December 31, 2020.

3.2. The other unit must cease no later than December 31, 2025.

3.3. The unit that continues coal-fired power generation operations starting January 1, 2021, must comply with section 1.1.3.

3.4. Conditions 3.1 and 3.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

[First amendment of the December 23, 2011, Memorandum of Agreement between the State of Washington and TransAlta Centralia Generation LLC, dated July 13, 2017.]

Monitoring and Recordkeeping Requirements

4. Ammonia

TransAlta is required to meet the nitrogen oxides emission limits of 1.1.1 and 1.1.2. Ammonia monitoring is only required when urea injection is used to meet those limits. The entirety of Section 4 applies in any calendar year (CY) in which urea injection is used by TransAlta to meet the emission limits of 1.1.1 or 1.1.2. TransAlta is not required to perform any of the monitoring and recordkeeping requirements in Section 4 if urea is not injected in the CY.

4.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

4.1.1. Testing shall occur once each calendar year if the ammonia feed-rate exceeds 1.5 gpm during that calendar year. Testing will be performed while the SNCR is in operation and the feed-rate is above 1.5 gpm during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

4.1.2. If two consecutive tests are each more than the ammonia limitation (in 2.1.1), then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

4.1.3. If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

4.1.4. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

5. Nitrogen oxides monitoring and averaging

5.1. For any hour in which coal is combusted in a unit, the owner/operator of that unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu multiplied by unit heat input) from that operating unit and dividing that by the sum of the hourly heat inputs in million Btu for that operating unit. At the end of that boiler's operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and the previous 29 successive boiler operating days.

5.2. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

5.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

5.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

Reporting Requirements

6. A letter reporting achievement of each compliance date in the schedule in Condition 3 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

7. A letter reporting TransAlta used urea injection must be sent to Ecology and SWCAA within 30 days of the first urea injection occurring during each calendar year. The letter must contain, at a minimum, the dates of urea injection, urea concentration, and the urea injection rate. No letter is required for any calendar year in which no urea injection occurred.

8. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with 30 days after the end of each calendar quarter. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

9. Emission monitoring data will be reported to Ecology and to the SWCAA.

9.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

9.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported as lb/MMBtu, with at least two significant figures;

9.1.2. The cumulative short tons of nitrogen oxides per unit and for both units combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

9.1.3. The results of Section 4 testing for ammonia emissions, if they are required, shall be submitted within 45 days of completion of the test.

9.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to SWCAA.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board PO Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 1111 Israel Rd. SW, STE 301 Tumwater, WA 98501

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
PO Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Philip Gent
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at https://www.eluho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this _29th__ day of _July_, 2020 at Olympia, Washington.

Martha Hankins
Manager, Policy and Planning Section
Department of Ecology
Air Quality Program

502785583 v2

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-51:
2020 BART Order Technical Support

DEPARTMENT OF ECOLOGY
State of Washington

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

July 2020

Publication and Contact Information

For more information, contact:

Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600
360-407-6800

Washington State Department of Ecology — www.ecology.wa.gov

- Headquarters, Olympia 360-407-6000
- Northwest Regional Office, Bellevue 425-649-7000
- Southwest Regional Office, Olympia 360-407-6300
- Central Regional Office, Union Gap 509-575-2490
- Eastern Regional Office, Spokane 509-329-3400

ADA Accessibility

To request ADA accommodation, email phil.gent@ecy.wa.gov or call 360-407-6810, 711 (relay service), or 877-833-6341 (TTY).

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

Air Quality Program

Washington State Department of Ecology

Olympia, Washington

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Table of Contents

Executive Summary

TransAlta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. In 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. The proposed mitigation is for TransAlta to install and operate a Combustion Optimization System with Neural Network (Neural Net) and have a lower nitrogen oxides (NOx) emission limit on the unit that is operational beyond 2020.

TransAlta was previously required to install Selective Non-Catalytic Reduction (SNCR) for control of nitrogen oxides emitted from their Centralia Power Plant. As a condition of the BART order issued to the facility, an optimization study was required to be performed and the results of that study implemented by the facility. After conducting the optimization study, TransAlta discovered that the ESPs were fouled from ammonia use required in the current BART order (Revision 1).

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

TransAlta, Southwest Clean Air Agency, and Ecology agreed on the conditions for Revision 2 for the BART order to include lower nitrogen oxides limits, changes to the use and monitoring of ammonia, and removal of the requirement to analyze the coal sulfur and nitrogen content.

Reason for this Revision

Trans Alta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. The proposed mitigation is for TransAlta to install in one boiler unit a Combustion Optimization System with Neural Network (Neural Net) in order to reduce the urea injection rate (the source of the ammonia). The other boiler unit is currently slated to cease coal-fired power generation on December 31, 2020 and is not scheduled to have the Neural Net installed. Ecology and Southwest Clean Air Agency are willing to accept a lower urea injection rate if TransAlta is willing to accept a lower nitrogen oxides emission limit. Ecology has determined that the nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission limit on one unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.
- Changing the language to "Permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives" to match the new language in the MOA.
- Removing the requirement to sample the coal for nitrogen and sulfur content.
- Removing the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement of a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Changing the requirement for ammonia emission monitoring only to require monitoring when using a urea injection rate of greater than 1.5 gallons per minute

Ecology is also modifying the compliance schedule to eliminate the requirement to demolish the coal units to align the BART order's language with language in the Memorandum of Understanding (MOA) between the State of Washington and TransAlta.

SNCR and Other Related Changes

The requirement to install SNCR along with the requirement to meet Washington's greenhouse gas emission performance standard was enacted by the legislature in 2010. The legislative requirement resulted in the first BART order revision. This first revision was finalized in December 2011 and approved by EPA December 16, 2012.

Originally, Revision 2 was intended to incorporate the results of the SNCR Optimization Study required by Condition 5 of the First Revision of the amended 2012 BART order. The study was to demonstrate the proper use of ammonia in controlling emissions of nitrogen oxides generated by the combustion of coal in the TransAlta boilers. Goals of the study were to determine how low nitrogen oxides emissions could be attained while meeting an ammonia slip limit of 10 ppm.

TransAlta completed the required ammonia injection optimization testing in two phases. The first phase was completed and the required report submitted in September 2014. Ecology and Southwest Clean Air Agency requested additional testing. This additional testing was performed and updated test results were submitted in August 2016. The updated test results were accepted by Ecology and Southwest Clean Air Agency on November 7, 2016. Ecology's letter accepting the final report included a requirement for urea injection in Unit 1 at 1.2 gallons per minute and 2.0 gallons/minute in unit 2. The prescribed urea injection level was constant for all power generation levels.

Condition 5 of the First Revision of the BART order required TransAlta to submit a request to revise the BART order to reflect the results of the study. In a letter dated November 28, 2016, TransAlta requested specific revisions to the BART order to reflect the findings of the study.

Before Ecology was able to take action on TransAlta's request, TransAlta started a third optimization study in response to a compliance order with Southwest Clean Air Agency. The intent of the third optimization study was to fine-tune certain plant operating parameters and verify the result of the second optimization study. The results of the third study would augment or replace the results of the previous studies. An initial SNCR optimization test plan was submitted to Ecology by email on February 6, 2019.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shut-down of the facility, the electrostatic precipitators (ESPs) were examined. The ESPs had a visual fouling of all interior components, which dramatically reduced their efficiency. Samples of the material in the ESPs were analyzed and identified as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

To decrease the ammonia slip in the SNCR, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net). The Neural Net is able to monitor and adjust more system variables at the same time than the manual control system. TransAlta notified Ecology and Southwest Clean Air Agency by email on July 8, 2019 of the installation of the Neural Net and the start of tuning the system.

TransAlta submitted a request on January 30, 2020 to modify Revision 1 of the BART order. The modification proposes the installation of the Neural Net and eliminates the mandatory urea injection requirements.

Revision 2 incorporates those changes and removes outdated requirements.

Compliance schedule related change

On July 13, 2017, the Memorandum of Agreement (MOA) between the State of Washington and TransAlta was amended. Subsection D(5) of the Recitals was modified. The 2011 MOA stated, "permanently cease power generation…" The 2017 MOA amendment reads:

> (5) permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA.

The change in the MOA does not require decommissioning of the units as envisioned (but not explicitly required) in 2011 with the passage of Chapter 180 (see Laws of 2011 - ESSB 5769 in 2011, codified in several locations). The change in the order reflects the pertinent portions of this law as codified in Chapters 80.80 and 80.82 RCW.

Ecology used the 2011 expectation that the plant would close to comply with the greenhouse gas emissions performance standard in RCW 80.08.040(3). Ecology also used the planned closure of the plant in the 2011 Regional Haze State Implementation Plan to project visibility benefits from the plant meeting the standard according to the schedule in the law. If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.

If TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU). This is similar to what we would require of a new power plant to determine if it meets the requirements of WAC 173-400-117, special protection requirements for federal Class I areas.

Basis for Decision

SNCR related changes and optimization study

As directed by BART order revision 1 and RCW 80.80.040, TransAlta installed an SNCR system to reduce nitrogen oxides emissions from the boilers. The installation was based on a design study by the system vendor, NALCO-NOx Mobotec.

NALCO/Mobotec took system measurements adequate to model the combustion process and optimize the locations of ammonia injection into the boilers. Modeling indicated that due to the configuration of the boilers, the lowest nitrogen oxides emission rate anticipated would be approximately 0.195 lb/MMBtu, assuming that modifications to optimize combustion in the fireboxes for Powder River Basin (PRB) sub-bituminous coal were completed.

Only Unit 2 (aka BW22) was modified for optimizing the combustion of PRB coals. These modifications, proposed in 2007, are known as the Flex Fuels Project. Unit 1 (aka BW21) is not modified and the company indicates that it is unlikely that the modifications will be installed on this unit.

The installed SNCR system includes three levels of injection lances in each boiler. The actual lances used depends on the firing rate. In general, to avoid making nitrogen oxides by oxidizing ammonia, the higher lances are used at high firing rates and the lower lances are used at low firing rates.

Ammonia is supplied by using urea. Urea is received as a 40 percent by weight urea solution. The urea is supplied to the lances via a variable speed pump that can supply up to 6 gallons per minute of the 40 percent urea solution to an eductor system. The water provides some cooling to the hot flue gas and carries the urea well beyond the lance ports allowing the nitrogen oxides reduction to occur over more volume of the boiler. At maximum injection rates, the system is capable of injecting ammonia at approximately the stoichiometric rate for the SNCR reaction at maximum heat input.

The modeling by NALCO/Mobotec on maximum reduction of nitrogen oxides has proven to be accurate in practice. Boiler/SNCR system modeling indicated that the maximum expected nitrogen oxides reduction would give an emission rate of 0.195 lb/MMBtu. Testing indicates that on Unit 2, the maximum reduction is to 0.19 lb/MMBtu and for Unit 1, 0.20 lb/MMBtu.

The initial reduction testing (reported in the September 2014 Optimization Study report) indicated that at low injection rates, the installed SNCR systems did not reduce nitrogen oxides beyond the levels being achieved by the use of the installed combustion controls. There was no significant nitrogen oxides reduction when the SNCR and combustion controls were both operated concurrently. The 2014 Optimization Study report indicated that the combination of SNCR and combustion control could achieve 0.21 lb nitrogen oxides/MMBtu. The current nitrogen oxides emission limit has been set to the achievable emission level of 0.21 lb nitrogen oxides/MMBtu.

Ecology and Southwest Clean Air Agency required TransAlta to complete additional urea injection studies to determine the effects of injection rates of up to 6 gpm of 40 percent urea solution on nitrogen oxides reduction. Two test series on each boiler were done at 2 boiler operating rates:

- A series of 15-minute tests at an operating rate of 686 MW, gross, and
- A series of 15-minute and 4 hours tests were done at an operating rate of 600 MW, gross.

Conclusions of TransAlta's optimization study

In conclusion, the 2014 and 2016 test results indicate that the injection rates developed by NALCO/Mobotec as their optimum injection rates are very close to what has been demonstrated in the most current study. TransAlta presented rationale for why the emission limits in the BART order should not be adjusted downward.

TransAlta's rationale included a conclusion that the effectiveness of the SNCR system is affected by numerous operational parameters. The plant operators have control over some, while others are out of their control. Operating parameters include market driven operating rates, fuel blend, physical condition of the boiler and auxiliary equipment, fuel staging at burners, air flow distribution, burner tilt, soot blowing intervals, tube fouling, water wall slagging, and temperature in the convective pass of the boiler. TransAlta argued that because the uncertainties listed above, the BART order should not be adjusted.

Ecology's evaluation of the optimization data

Test results indicate that a small reduction in average nitrogen oxides emissions may be achievable. The actual reduction depends on several operating parameters. Ecology has evaluated the possibility of reducing the 30-day average limitation from 0.21 to 0.20 lb/MMBtu. We note that if both units operated at full rate for every hour of the year (i.e., the potential to emit), a 0.01 lb/MMBtu reduction equates to about 590 tons per year out of a potential to emit rate of 12,900 tons.

TransAlta's current permits require the operation of the SNCR system with urea injection and emission limits of 0.21 lb/MMBtu. The urea injection rate is creating ammonia slip. The ammonia generation is reacting with sulfur to create ammonia sulfate that is plating the surfaces in the ESPs. This creates conditions where the facility has to run at a reduced rate to continuing meeting emission requirements.

Neural Net

TransAlta initial proposal was to substitute the Neural Net to reduce the urea injection rate for each unit. Ecology and Southwest Clean Air Agency were willing to accept a lower urea injection rate, but wanted TransAlta to meet the short-term emission values of 0.18 lb/MMBtu for the unit with the Neural Net installed on it. In July 2019, TransAlta did not know the effectiveness of the Neural Net system. TransAlta requested a delay in agreement until more testing was done.

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

The main elements of the request are to:

- Install the Neural Net on Unit 2.
- Change the emission standard on Unit 2 to 0.18 lb/MMBtu from 0.21 lb/MMBtu.
- Allow TransAlta to use all methods and options they have available in any combination to meet the 0.18 lb/MMBtu standard.
- Change the ammonia monitoring requirements to reflect both historical readings and the change in urea injection rates.
- Remove the testing of coal for nitrogen and sulfur content as the facility would have to meet emission standards regardless of the coal used.
- Remove the reporting requirements for the coal nitrogen and sulfur content, as the test would no longer be performed.
- Change the permit language to reflect the new MOA language.

Compliance schedule related changes

The requirements of Chapter 80.80 RCW that sets the compliance schedule simply requires that to continue operation as a baseload power plant after the schedule in RCW 80.80.040(3)(c) and the BART order, each boiler must meet the greenhouse gas emission performance standard in effect on the day after the compliance dates. The standard is set by Washington Department of Commerce based on the emissions of combined cycle combustion turbines offered for sale and installed in the United States. This standard is currently 970 pounds of greenhouse gases/MWh. The standard is currently under review by Commerce for potential revision downward.

To continue operation after 2020 and 2025 with emissions above the greenhouse gas emission performance standard would require the plant owners to take an enforceable limit that keeps operations annually below a 60 percent capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW.

Ecology Analysis

The change in MOA language does not exclude the possibility that TransAlta could retrofit the facility to natural gas and continue operation. As the current BART order revision request does not address the future operation of the plant after 2025, any changes of this nature will require a separate action on the part of TransAlta. Until such time, it is assumed that TransAlta will cease all power generation activities by 2025.

Chapter 80.82 RCW was enacted in the same legislation that enacted special requirements for the Centralia Power Plant in Chapter 80.80 RCW. This law was drafted with the explicit understanding that the coal units would be decommissioned and demolished rather than repowered.

Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan.

Proposed revision to emission limit in BART order

Ecology has determined that the small nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology has determined that a change in ammonia monitor is applicable with the change from a mandatory urea injection rate to a rate dependent on meeting a specific nitrogen oxides emission standard. TransAlta historic ammonia emission sampling at their current urea injection rate has never indicated excessive ammonia emissions. A large part in this finding is that the SNCR is upstream in the emission pathway from the wet scrubber. Free ammonia in the exhaust stream would be absorbed by the slurry stream in the wet scrubber, as ammonia is hydrophilic. These two factors allow for modification of the ammonia monitoring.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission standard on the second unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.

- Change the language to “permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives.” This to match the new language in the MOA.
- Remove the requirement to sample the coal for nitrogen and sulfur content.
- Remove the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Change the requirement for ammonia emission monitoring to reflect monitoring when using a urea injection rate of greater than 1.5 gallons per minute.

Proposed revision to compliance schedule in BART order

Ecology is proposing to modify the compliance schedule for coal units BW21 and BW22 to permanently cease coal-fired power generation operations by 2020 and 2025. This much more closely matches the requirement in the underlying state law.

Any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled. The modeling would have to meet both the requirements of BART modeling and satisfy the requirement of WAC 173-400-117. Since TransAlta has not requested repowering at this time, this issue will not be addressed in this BART order revision.

References

TransAlta’s SNCR Optimization Study Report, September 20, 2014

TransAlta’s SNCR Optimization Study Report, August 15, 2016

Ecology’s SNCR Optimization Study Report acceptance letter dated November 7, 2016

Letter to Nancy Pritchett and Uri Papish, dated November 28, 2016

Southwest Clean Air Agency Regulatory Order #16-3202, issued December 13, 2016

TVW recording of March 15, 2011 House Environment Committee

Emission calculation

Appendix:

Response to Comment

From:	Gent, Philip (ECY)
To:	emissol@emissol.co
Subject:	Response to submitted comment on TransAlta"s proposed BART Revision
Date:	Monday, July 27, 2020 4:39:00 PM

To whom it may concern,

You submitted a comment in regards to a proposed revision to the TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant's Best Available Retrofit Technology (BART) Order on 5/19/2020 at 1420. Below you will find your submitted comment and Ecology's response to your comment.

Submitted Comment

"Neural Network (NN) is a complex method and requires substantial testing, development and validation in order to make it work for any given environment. We trust the applicant has gone thru its due process for this development and demonstration. It is imperative that sufficient evidence is provided, showing a certain NN algorithm has been developed and specifically shown to work for the said environment in the powerplant."

Response to comment

Thank you for your comment. TransAlta along with Neuendorfer and Griffin Open Systems installed a temporary neural network interfacing with the plant distributed control system starting July 8, 2019. The system had no control elements and was only learning and modeling the systems. Griffin engineers built a model to perform predictive modeling and started to collect tuning data.

The neural network interface continued to collect tuning data and in October, 2019, TransAlta Corporate approved and issued an authorization for expenditure for the entire neural network installation. The installation plan was to have the neural network operational the first week of November. The actual transition time took longer than planned and the commission date was extended to December 19, 2019.

The months of installation and modification of the neural network in order to reduce and optimize NOx emissions gave TransAlta the confidence to request a change to their existing BART Order. From the time of control system commissioning (December 19, 2019 being the day Griffin and Neuendorfer left the site) until the unit came offline for the spring outage on February 11, 2020, average NOX emissions have been below 0.18 lb/MMBtu. As the request to lower the NOx emission limit came from the Permittee (TransAlta), it is incumbent on TransAlta to meet the limits.

No change was made to the BART Order as a result of this comment.

Philip Gent, PE
Senior Engineer
Policy & Planning Section
Washington Department of Ecology
(360) 407-6810
Philip.Gent@ecy.wa.gov

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-52:
Centralia Hazardous Substances Releases: Preliminary Determination (Sept. 2025)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Southwest Region Office
PO Box 47775 • Olympia, WA 98504-7775 • 360-407-6300

September 4, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Preliminary Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

Based on credible evidence, the Department of Ecology (Ecology) is proposing to find TransAlta Centralia Generation LLC liable under the Model Toxics Control Act (MTCA), Chapter 70A.305 RCW, for the release of hazardous substances at the Centralia Steam Plant (Site). Any person whom Ecology finds, based on credible evidence, to be liable is known under MTCA as a "potentially liable person" or "PLP."

This letter identifies the basis for Ecology's proposed finding and your opportunity to respond to that finding. This letter also describes the scope of your potential liability and next steps in the cleanup process at the Site.

Proposed Finding of Liability

Ecology is proposing to find TransAlta Centralia Generation LLC liable under RCW 70A.305.040 for the release of hazardous substances at the Site. This proposed finding is based on the following evidence:

1. TransAlta Centralia Generation LLC is the current owner and operator of the TransAlta Steam Plant (Site) located at 913 Big Hanaford Rd, Centralia Washington 98531 including Lewis County Parcels **23340001000,23340002002,23340003000,23340004000,23340005001,233400**

05002,
23340005003,23340005004,23436000000,23345000000,23355001006,23355001007,
23355001008,23355002002.

2. The property is and has been historically operated as a coal-fired electric plant with associated energy production activities.

3. The owner has provided a draft remedial investigation (TRC Environmental Corporation, Remedial Investigation Report, TransAlta Centralia Generation LLC, 913 Big Hanaford Road, Centralia WA, May 13, 2025) that identifies releases including metals, volatile organic compounds, semi-volatile organic compounds (SVOCs), and total petroleum hydrocarbons, to soil, groundwater, and sediment above MTCA cleanup levels. The facility's operation as a coal burning power generation plant likely released particulate containing dioxins and furans, SVOCs, and select metals including mercury from its smokestacks into the environment surrounding the facility.

Opportunity to Respond to Proposed Finding of Liability

In response to Ecology's proposed finding of liability, you may either:

1. Accept your status as a PLP without admitting liability and expedite the process through a voluntary waiver of your right to comment. This may be accomplished by signing and returning the enclosed form or by sending a letter containing similar information to Ecology; or

2. Challenge your status as a PLP by submitting written comments to Ecology within thirty (30) calendar days of the date you receive this letter; or

3. Choose not to comment on your status as a PLP.

Please submit your waiver or written comments to the following address:

Thomas Middleton
Southwest Regional Office
Toxics Cleanup Program
PO Box 47775
Olympia, WA 98504-7775

After reviewing any comments submitted, or after 30 days if no response has been received, Ecology will make a final determination regarding your status as a PLP and provide you with written notice of that determination.

Identification of Other Potentially Liable Persons

If you are aware of any other persons who may be liable for the release of hazardous substances at the Site, Ecology encourages you to provide us with their identities and the reason you believe they are liable. Ecology also suggests you contact these other persons to discuss how you can jointly work together to most efficiently clean up the Site.

Responsibility and Scope of Potential Liability

Ecology may either conduct or require PLPs to conduct remedial actions to investigate and clean up the release of hazardous substances at a site. PLPs are encouraged to initiate discussions and negotiations with Ecology and the Office of the Attorney General that may lead to an agreement on the remedial action to be conducted.

Each liable person is strictly liable, jointly and severally, for all remedial action costs and for all natural resource damages resulting from the release of hazardous substances at a site. If Ecology incurs remedial action costs in connection with the investigation or cleanup of real property and those costs are not reimbursed, then Ecology has the authority under RCW 70A.305.060 to file a lien against that real property to recover those costs.

Next Steps in Cleanup Process

In response to the release of hazardous substances at the Site, Ecology intends to conduct the following actions under MTCA:

1. Ecology has completed the Initial Investigation/Site Hazard Assessment (II/SHA) and prepared an Early Notice Letter (ENL). Ecology will engage with TransAlta Generation Centralia LLC to develop an Agreed Order at the Site.

2. Ecology will continue to work with TransAlta Generation Centralia LLC to complete its closure requirements and obligations under RCW Chapter 80.82 and the Memorandum of Agreement between TransAlta and the State of Washington dated December 23, 2011.

For a description of the process for cleaning up a contaminated site under MTCA, please refer to the enclosed fact sheet.

Ecology’s policy is to work cooperatively with PLPs to accomplish the prompt and effective cleanup of contaminated sites. Please note that your cooperation in planning or conducting remedial actions at the Site is not an admission of guilt or liability.

Contact Information

If you have any questions regarding this letter or if you would like additional information regarding the cleanup of contaminated sites, please contact me at 360-999-9594 or thomas.middleton@ecy.wa.gov. Thank you for your cooperation.

Sincerely,

Thomas Middleton
Cleanup Project Manager
Toxics Cleanup Program, SWRO

Enclosures (2)

1. FOCUS: MODEL TOXICS CONTROL ACT CLEANUP REGULATION: PROCESS FOR CLEANUP OF HAZARDOUS WASTE SITES (#94-129)
2. PLP WAIVER FORM TEMPLATE

By certified mail: 9489 0090 0027 6341 0492 85

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General:dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Marian Abbett, SWRO TCP Section Manager: marian.abbett@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

Focus

Model Toxics Control Act Cleanup Regulation: Process for Cleanup of Hazardous Waste Sites

In March of 1989, an innovative, citizen-mandated toxic waste cleanup law went into effect in Washington, changing the way hazardous waste sites in this state are cleaned up. Passed by voters as Initiative 97, this law is known as the Model Toxics Control Act, chapter 70.105D RCW. This fact sheet provides a brief overview of the process for the cleanup of contaminated sites under the rules Ecology adopted to implement that Act (chapter 173-340 WAC).

How the Law Works

The cleanup of hazardous waste sites is complex and expensive. In an effort to avoid the confusion and delays associated with the federal Superfund program, the Model Toxics Control Act is designed to be as streamlined as possible. It sets strict cleanup standards to ensure that the quality of cleanup and protection of human health and the environment are not compromised. At the same time, the rules that guide cleanup under the Act have built-in flexibility to allow cleanups to be addressed on a site-specific basis.

The Model Toxics Control Act funds hazardous waste cleanup through a tax on the wholesale value of hazardous substances. The tax is imposed on the first in-state possessor of hazardous substances at the rate of 0.7 percent, or $7 per $1,000. Since its passage in 1988, the Act has guided the cleanup of thousands of hazardous waste sites that dot the Washington landscape. The Washington State Department of Ecology's Toxic Cleanup Program ensures that these sites are investigated and cleaned up.

What Constitutes a Hazardous Waste Site?

Any owner or operator who has information that a hazardous substance has been released to the environment at the owner or operator's facility and may be a threat to human health or the environment must report this information to the Department of Ecology (Ecology). If an "initial investigation" by Ecology confirms further action (such as testing or cleanup) may be necessary, the facility is entered onto either Ecology's "Integrated Site Information System" database or "Leaking Underground Storage Tank" database. These are computerized databases used to track progress on all confirmed or suspected contaminated sites in Washington State. All confirmed sites that have not been already voluntarily cleaned up are ranked and placed on the state "Hazardous Sites List." Owners, operators, and other persons known to be potentially liable for the cleanup of the site will receive an "Early Notice Letter" from Ecology notifying them that their site is suspected of needing cleanup, and that it is Ecology's policy to work cooperatively with them to accomplish prompt and effective cleanup.

Who is Responsible for Cleanup?

Any past or present relationship with a contaminated site may result in liability. Under the Model Toxics Control Act a potentially liable person can be:

- A current or past facility owner or operator.
- Anyone who arranged for disposal or treatment of hazardous substances at the site.
- Anyone who transported hazardous substances for disposal or treatment at a contaminated site, unless the facility could legally receive the hazardous materials at the time of transport.
- Anyone who sells a hazardous substance with written instructions for its use, and abiding by the instructions results in contamination.

In situations where there is more than one potentially liable person, each person is jointly and severally liable for cleanup at the site. That means each person can be held liable for the entire cost of cleanup. In cases where there is more than one potentially liable person at a site, Ecology encourages these persons to get together to negotiate how the cost of cleanup will be shared among all potentially liable persons.

Ecology must notify anyone it knows may be a "potentially liable person" and allow an opportunity for comment before making any further determination on that person's liability. The comment period may be waived at the potentially liable person's request or if Ecology has to conduct emergency cleanup at the site.

Achieving Cleanups through Cooperation

Although Ecology has the legal authority to order a liable party to clean up, the department prefers to achieve cleanups cooperatively. Ecology believes that a non-adversarial relationship with potentially liable persons improves the prospect for prompt and efficient cleanup. The rules implementing the Model Toxics Control Act, which were developed by Ecology in consultation with the Science Advisory Board (created by the Act), and representatives from citizen, environmental and business groups, and government agencies, are designed to:

- Encourage independent cleanups initiated by potentially liable persons, thus providing for quicker cleanups with less legal complexity.
- Encourage an open process for the public, local government and liable parties to discuss cleanup options and community concerns.
- Facilitate cooperative cleanup agreements rather than Ecology-initiated orders. *Ecology can, and does, however use enforcement tools in emergencies or with recalcitrant potentially liable persons*.

What is the Potentially Liable Person's Role in Cleanup?

The Model Toxics Control Act requires potentially liable persons to assume responsibility for cleaning up contaminated sites. For this reason, Ecology does not usually conduct the actual cleanup when a potentially liable person can be identified. Rather, Ecology oversees the cleanup of sites to ensure that investigations, public involvement and actual cleanup and monitoring are done appropriately. Ecology's costs of this oversight are required to be paid by the liable party.

When contamination is confirmed at the site, the owner or operator may decide to proceed with cleanup without Ecology assistance or approval. Such "independent cleanups" are allowed under the Model Toxics Control Act under most circumstances, but must be reported to Ecology, and are done at the owner's or operator's own risk. Ecology may require additional cleanup work at these sites to bring them into compliance with the state cleanup standards. Most cleanups in Washington are done independently.

Other than local governments, potentially liable persons conducting independent cleanups do not have access to financial assistance from Ecology. Those who plan to seek contributions from other persons to help pay for cleanup costs need to be sure their cleanup is "the substantial equivalent of a department-conducted or department-supervised remedial action." Ecology has provided guidance on how to meet this requirement in WAC 173-340-545. Persons interested in pursuing a private contribution action on an independent cleanup should carefully review this guidance prior to conducting site work.

Working with Ecology to Achieve Cleanup

Ecology and potentially liable persons often work cooperatively to reach cleanup solutions. Options for working with Ecology include formal agreements such as consent decrees and agreed orders, and seeking technical assistance through the Voluntary Cleanup Program. These mechanisms allow Ecology to take an active role in cleanup, providing help to potentially liable persons and minimizing costs by ensuring the job meets state standards the first time. This also minimizes the possibility that additional cleanup will be required in the future – providing significant assurances to investors and lenders.

Here is a summary of the most common mechanisms used by Ecology:

- **Voluntary Cleanup Program**: Many property owners choose to cleanup their sites independent of Ecology oversight. This allows many smaller or less complex sites to be cleaned up quickly without having to go through a formal process. A disadvantage to property owners is that Ecology does not approve the cleanup. This can present a problem to property owners who need state approval of the cleanup to satisfy a buyer or lender.

  One option to the property owner wanting to conduct an independent cleanup yet still receive some feedback from Ecology is to request a technical consultation through Ecology's Voluntary Cleanup Program. Under this voluntary program, the property owner submits a cleanup report with a fee to cover Ecology's review costs. Based on the review, Ecology either issues a letter stating that the site needs "No Further Action" or identifies what additional work is needed. Since Ecology is not directly involved in the site cleanup work, the level of certainty in Ecology's response is less than in a consent decree or agreed order. However, many persons have found a "No Further Action" letter to be sufficient for their needs, making the Voluntary Cleanup Program a popular option.

- **Consent Decrees:** A consent decree is a formal legal agreement filed in court. The work requirements in the decree and the terms under which it must be done are negotiated and agreed to by the potentially liable person, Ecology and the state Attorney General's office. Before consent decrees can become final, they must undergo a public review and comment period that typically includes a public hearing. Consent decrees protect the potentially liable person from being sued for "contribution" by other persons that incur cleanup expenses at the site while facilitating any contribution claims against the other persons when they are responsible for part of the cleanup costs. Sites cleaned up under a consent decree are also exempt from having to obtain certain state and local permits that could delay the cleanup.

- ***De Minimus* Consent Decree:** Landowners whose contribution to site contamination is "insignificant in amount and toxicity" may be eligible for a de minimus consent decree. In these decrees, landowner typically settle their liability by paying for some of the cleanup instead of actually conducting the cleanup work. Ecology usually accepts a de minimus settlement proposal only if the landowner is affiliated with a larger site cleanup that Ecology is currently working on.
- **Prospective Purchaser Consent Decree:** A consent decree may also be available for a "prospective purchaser" of contaminated property. In this situation, a person who is not already liable for cleanup and wishes to purchase a cleanup site for redevelopment or reuse may apply to negotiate a prospective purchaser consent decree. The applicant must show, among other things, that they will contribute substantial new resources towards the cleanup. Cleanups that also have a substantial public benefit will receive a higher priority for prospective purchaser agreements. If the application is accepted, the requirements for cleanup are negotiated and specified in a consent decree so that the purchaser can better estimate the cost of cleanup before buying the land.
- **Agreed Orders:** Unlike a consent decree, an agreed order is not filed in court and is not a settlement. Rather, it is a legally binding administrative order issued by Ecology and agreed to by the potentially liable person. Agreed orders are available for remedial investigations, feasibility studies, and final cleanups. An agreed order describes the site activities that must occur for Ecology to agree not to take enforcement action for that phase of work. As with consent decrees, agreed orders are subject to public review and offer the advantage of facilitating contribution claims against other persons and exempting cleanup work from obtaining certain state and local permits.

Ecology-Initiated Cleanup Orders

Administrative orders requiring cleanup activities without an agreement with a potentially liable person are known as **enforcement orders**. These orders are usually issued to a potentially liable person when Ecology believes a cleanup solution cannot be achieved expeditiously through negotiation or if an emergency exists. If the responsible party fails to comply with an enforcement order, Ecology can clean up the site and later recover costs from the responsible person(s) at up to three times the amount spent. The state Attorney General's Office may also seek a fine of up to $25,000 a day for violating an order. Enforcement orders are subject to public notification.

Financial Assistance

Each year, Ecology provides millions of dollars in grants to local governments to help pay for the cost of site cleanup. In general, such grants are available only for sites where the cleanup work is being done under an order or decree. Ecology can also provide grants to local governments to help defray the cost of replacing a public water supply well contaminated by a hazardous waste site. Grants are also available for local citizen groups and neighborhoods affected by contaminated sites to facilitate public review of the cleanup. See Chapter 173-322 WAC for additional information on grants to local governments and Chapter 173-321 WAC for additional information on public participation grants.

Public Involvement

Public notices are required on all agreed orders, consent decrees, and enforcement orders. Public notification is also required for all Ecology-conducted remedial actions.

Ecology's Site Register is a widely used means of providing information about cleanup efforts to the public and is one way of assisting community involvement. The Site Register is published every two weeks to inform citizens of public meetings and comment periods, discussions or negotiations of legal agreements, and other cleanup activities. The Site Register can be accessed on the Internet at: www.ecy.wa.gov/programs/tcp/pub_inv/pub_inv2.html.

How Sites are Cleaned Up

The rules describing the cleanup process at a hazardous waste site are in chapter 173-340 WAC. The following is a general description of the steps taken during the cleanup of an average hazardous waste site. Consult the rules for the specific requirements for each step in the cleanup process.

1. Site Discovery: Sites where contamination is found must be reported to Ecology's Toxics Cleanup Program within 90 days of discovery, unless it involves a release of hazardous materials from an underground storage tank system. In that case, the site discovery must be reported to Ecology within 24 hours. At this point, potentially liable persons may choose to conduct independent cleanup without assistance from the department, but cleanup results must be reported to Ecology.

2. Initial Investigation: Ecology is required to conduct an initial investigation of the site within 90 days of receiving a site discovery report. Based on information obtained about the site, a decision must be made within 30 days to determine if the site requires additional investigation, emergency cleanup, or no further action. If further action is required under the Model Toxics Control Act, Ecology sends early notice letters to owners, operators and other potentially liable persons inviting them to work cooperatively with the department.

3. Site Hazard Assessment: A site hazard assessment is conducted to confirm the presence of hazardous substances and to determine the relative risk the site poses to human health and the environment.

4. Hazard Ranking: The Model Toxics Control Act requires that sites be ranked according to the relative health and environmental risk each site poses. Working with the Science Advisory Board, Ecology created the Washington Ranking Method to categorize sites using data from site hazard assessments. Sites are ranked on a scale of 1 to 5. A score of 1 represents the highest level of risk and 5 the lowest. Ranked sites are placed on the state Hazardous Sites List.

5. Remedial Investigation/Feasibility Study: A remedial investigation and feasibility study is conducted to define the extent and magnitude of contamination at the site. Potential impacts on human health and the environment and alternative cleanup technologies are also evaluated in this study. Sites being cleaned up by Ecology or by potentially liable persons under a consent decree, agreed order or enforcement order are required to provide for a 30 day public review before finalizing the report.

6. Selection of Cleanup Action: Using information gathered during the study, a cleanup action plan is developed. The plan identifies preferred cleanup methods and specifies cleanup standards and other requirements at the site. A draft of the plan is subject to public review and comment before it is finalized.

7. Site Cleanup: Actual cleanup begins when the cleanup action plan is implemented. This includes design, construction, operation and monitoring of cleanup actions. A site may be taken off the Hazardous Sites List after cleanup is completed and Ecology determines cleanup standards have been met.

PLP Waiver Form Template

[PLP SIGNATORY]
[PLP COMPANY]
[STREET ADDRESS]
[CITY, STATE] [POSTAL CODE]

Pursuant to WAC 173-340-500 and WAC 173-340-520(1)(b)(i), I [NAME], a duly authorized representative of [COMPANY NAME], do hereby waive the right to the thirty (30) day notice and comment period described in WAC 173-340-500(3) and accept status of [COMPANY NAME] as a Potentially Liable Person at the following contaminated site:

- Site Name: [CLEANUP SITE NAME]
- Site Address: [CLEANUP SITE ADDRESS]
- Cleanup Site ID: [CLEANUP SITE NUMBER]
- Facility/Site ID: [FACILITY/SITE NUMBER]
- [OPTIONAL: County Assessor's Parcel Number(s): [NUMBERS]]

By waiving this right, [COMPANY NAME] makes no admission of liability.

________________________________ ________________________________

Signature Date

Relation to the Site: [for example, owner or operator]

For More Information / Special Accommodation Needs

If you would like more information about the state Model Toxics Control Act, please call us toll-free at **1-800-826-7716**, or contact your regional Washington State Department of Ecology office listed below. Information about site cleanup, including a listing of ranked hazardous waste sites, is also accessible through our Internet address: http://www.ecy.wa.gov/programs/tcp/cleanup.html

- **Northwest Regional Office** **425/649-7000**
  (Island, King, Kitsap, San Juan, Skagit, Snohomish, Whatcom Counties)
- **Southwest Regional Office** **360/407-6300**
  (Southwestern Washington, Olympic Peninsula, Pierce, Thurston and Mason Counties)
- **Central Regional Office** **509/575-2490**
  (Benton, Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima Counties)
- **Eastern Regional Office** **509/329-3400**
  (Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman Counties)

If you need this publication in an alternative format, please contact the Toxics Cleanup Program at (360) 407-7170. Persons with a hearing loss can call 711 for the Washington Relay Service. Persons with a speech disability can call 877-833-6341.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC)	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-53:
Centralia Pollution Inspection (June 2025)

DEPARTMENT OF ECOLOGY
State of Washington

☐ Check this box if you have attached any documents to this form (using the paperclip icon on the left).

ERTS #(s):	**None**
Parcel # (s):	**See additional info box**
County:	Lewis
FSID #:	**94772166**
CSID #:	**17302**
UST #:	**8710**

SITE INFORMATION

Site Name (Name over door): **TransAlta Centralia**	Site Address (including City, State, and Zip): 913 Big Hanaford Rd, Centralia, WA 98531	Phone Click to enter text. Email **Click to enter text.**
Site Contact, Title, Business: **Conrad Wieclaw**	Site Contact Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-807-8093** Email **Conrad_Wieclaw@transalta.com** **Click to enter text.**
Site Owner, Title Business: **TransAlta Centralia Generation LLC**	Site Owner Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-736-9901** Email **Centralia@transalta.com**
Site Owner Contact, Title, Business: **Trans Alta Corporation**	Site Owner Contact Address (Including City, State, and Zip **TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta Canada T2G 1B1**	Phone **403-267-7110** Email **Click to enter text.**
Previous Site Owner(s): Alternate Site Name(s): **Click to enter text.**	Additional Info (for any Site Information Item): **23340001000,23340002002,23340003000,23340004000,23340005001,23340005002, 23340005003,23340005004,23436000000,23345000000,23355001006,23355001007, 23355001008,23355002002.**	

Latitude (Decimal Degrees):	**46.75487**
Longitude (Decimal Degrees):	**-122.8636**

☒ Please check this box if there is relevant inspection information, such as data or photos, in an existing site report for this site.

INSPECTION INFORMATION

Inspection Conducted? Yes ☐ No ☒	Date/Time: Click to enter text.	Entry Notice:	Announced ☐	Unannounced ☐
Photographs taken?	Yes ☐	No ☒	Note: Attach photographs or upload to PIMS	
Samples Collected?	Yes ☐	No ☒	Note: Attach record with media, location, depth, etc.	

RECOMMENDATION

No Further Action (Check appropriate box below):		**LIST on Contaminated Sites List:** ☒
Release or threatened release does not pose a threat	☐	
No release or threatened release	☐	**LIST on NFA Sites List:** ☐
Refer to program/agency (Name: **Click to enter text.**)	☐	
Independent Cleanup Action Completed (contamination removed)	☐	

COMPLAINT (Brief Summary of ERTS Complaint):

Property representatives reported contamination above MTCA cleanup standards during Site investigations

CURRENT SITE STATUS (Brief Summary of why Site is recommended for Listing or NFA):

I recommend this Site for a listing on the Contaminated Sites List. The submitted report indicates contamination above MTCA cleanup standards.

Investigator: **Thomas Middleton, L.HG**	Date Submitted: 6/2/2025

OBSERVATIONS ☐ **Please check this box if you included information on the Supplemental Page at end of report.**

Description (If site visit made, please be sure to include the following: site observations, site features and cover, chronology of events, sources/past practices likely responsible for contamination, presence of water supply wells and other potential exposure pathways, etc):

There are six COCs for soil at the Site. These COCs are further divided into nine Remedial Areas (RAs) for discussion of vertical and horizontal distribution of COCs in soil. The RAs are summarized below:

- **Arsenic:** Remedial Areas 1, 2, and 8. The distribution of arsenic impacts is displayed on Figures 12 and 13.
- **Barium:** Remedial Areas 1, 5, 6, 8, and 9. The distribution of barium impacts is displayed on Figures 14 and 15.
- **Cadmium:** Remedial Areas 3, 5, 6, and 8. The distribution of cadmium impacts is displayed on Figures 16 and 17.
- **Copper:** Remedial Areas 1, 4, and 7. The distribution of copper impacts is displayed on Figures 18 and 19.
- **Selenium**: Remedial Area 8. The distribution of selenium impacts is displayed on Figure 20.
- **Zinc**: Remedial Area 2. The distribution of zinc impacts is displayed on Figure 21.

As identified above, there are nine Remedial Areas (RAs) with COCs at concentrations exceeding CULs.

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There are nine COCs for groundwater at the Site. These COCs are summarized below and are based on groundwater samples collected from February 2023 to December 2024:

- **Arsenic (dissolved and total):** The distribution of arsenic impacts is displayed on Figures 23 through 27 in both the shallow and deep aquifers. The area of impacts in the shallow aquifer is predominantly near the Surge Pond, North Effluent Pond, and South Effluent Pond, with isolated pockets near the bottom ash pile and north of the North Coal Pile Runoff Ditch.

  The highest arsenic concentration in the deeper aquifer was from the off-property monitoring well CMWD-2 in both May and December 2024. Groundwater flow in the deeper aquifer is consistently toward the southeast. Based on the redox potential analysis of groundwater at the Site, these higher concentrations may be the result of anoxic groundwater conditions. Anoxic groundwater conditions significantly influence the mobility and concentration of naturally occurring arsenic and manganese at depth, especially where organic matter or other reducing agents are present.

- **Chromium (total):** The distribution of chromium impacts is displayed on Figures 28 through 30 in the shallow aquifer. No samples exceeded the chromium CUL from the deeper aquifer. Chromium impacts in the shallow aquifer exceeded CULs in monitoring wells CMW-16 (February 2023 and May 2024), CMW-32 (February 2023), and CMW-43 (December 2024). Corresponding chromium impacts to soil were not observed at levels exceeding CULs in these areas.

- **Copper (total):** While copper was retained as a COC for groundwater, only one sample exceeded the CUL in the shallow aquifer. Monitoring well CMW-16 exceeded the CUL in May 2024 at a concentration of 19 µg/L. The CUL for protection of surface water aquatic life is 11 µg/L. No samples exceeded the respective CUL from the deeper aquifer.

- **Manganese (dissolved and total):** The distribution of manganese impacts is displayed on Figures 31 through 35 in both the shallow and deep aquifers. Impacts to the shallow and deep aquifers were not fully delineated in May and December 2024 but the highest concentrations were observed upgradient of the facility, north of the CPRO Ponds and north of Hanaford Creek. This is most likely due to the naturally occurring metals at depth and the anoxic and hydric soil conditions to the north of the facility. As described in the 2019 Environmental Science & Technology, *Elevated Manganese Concentrations in United States Groundwater, Role of Land Surface- Soil- Aquifer Connections* (McMahon et al. 2018), the concentration of manganese is significantly higher in wells where hydric soils are present within a 500-meter buffer around the well.

- **Selenium (dissolved and total):** The distribution of selenium impacts is displayed on Figures 36 through 38 in the shallow aquifer. Selenium impacts exceeding the CUL of 5 µg/L were observed in the area surrounding the coal pile and the CPRO Ponds in February 2023 and December 2024. In May 2024, the selenium exceedances in the shallow aquifer were restricted to only monitoring well CMW-43, near Cooling Tower 1B.

  Selenium was not detected at a concentration exceeding the CUL of 80 µg/L in the deeper aquifer. The highest concentration in the deeper aquifer was 1.9 µg/L in December 2024 from monitoring well CMWD-1.

- **Zinc (dissolved and total):** The distribution of zinc impacts is displayed on Figures 39 through 41 in the shallow aquifer.

- **1-Methylnaphthalene:** 1-methlnaphthalene was detected in one monitoring well, CMW-16, exceeding the CUL of 0.86 µg/L. No other samples exceeded the MDL in both the shallow and deep aquifers.

- **TPH – Diesel-Range Organics:** The distribution of TPH-DRO impacts is displayed on Figures 42 through 44 in the shallow aquifer. Samples collected from monitoring well CMW-16, exceeded the CUL of 500 µg/L during all three sampling events. Based on the silica gel cleanup results collected in December 2024, there are other sources of polar organic compounds contributing to the weathered petroleum mixture, most likely from naturally occurring organic matter. Use of silica gel cleanup is recommended going forward to distinguish the non-petroleum polar organics in the samples. No TPH-DRO was detected exceeding the MDL in the deeper aquifer.

Vinyl Chloride: Vinyl chloride was only detected in two monitoring wells at a concentration exceeding the CUL of 0.02 µg/L for protection of surface water: temporary monitoring well CTMW-2 located south of the South Effluent Pond, and monitoring well CMW-27. The exceedance in temporary well CTMW-2 in February 2023 has not been encountered in surrounding groundwater monitoring wells CMW-6, CMW-8, and CMW-17.

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There are six COCs for sediment at the Site. The spatial distribution of these COCs exceeding the SCO is restricted to the CPRO Ponds, the North Effluent Pond, the South Effluent Pond, and the Coal Pile Runoff Ditches.

The sediment samples collected from Hanaford Creek were either less than the MDL or less than the sediment cleanup objective for all constituents analyzed and are not discussed further in this section.

Chemical concentrations that are less than or equal to the CSL but greater than the sediment cleanup objective correspond to sediment quality that results in minor adverse effects to the benthic community. The only constituents that exceeded the sediment screening level for protection of the benthic community were chromium and mercury. The distribution of COCs in sediment exceeding the SCO is as follows:

- **Arsenic:** The distribution of arsenic impacts is displayed on Figure 45. Sediment sample result\s exceeding the SCO were observed in the CPRO Ponds 2 through 8, the North Effluent Pond, and the East Coal Pile Runoff Ditch.
- **Cadmium:** The distribution of cadmium impacts is displayed on Figure 46. Sediment sample results exceeding the SCO were observed in the CPRO Ponds 3 through 8 and the North Effluent Pond. The sediment samples collected in the Coal Pile Runoff Ditches were all less than the MDL.
- **Chromium:** The distribution of chromium impacts is displayed on Figure 47. Sediment samples that exceeded the SCO were observed in CPRO Ponds 3, 4, 6, 7, and 8 and the North Effluent Pond. Six of the eight samples that exceeded the SCO also exceeded the SCL for chromium.
- **Mercury:** The distribution of mercury impacts is displayed on Figure 48. Sediment samples that exceeded the SCO were observed in the CPRO Pond 5, the North Effluent Pond, the South Effluent Pond, and the East Coal Pile Runoff Ditch. All samples that exceeded the SCO also exceeded the SCL for mercury.
- **Nickel:** The distribution of nickel impacts is displayed on Figure 49. Sediment samples that exceeded the SCO were observed in the CPRO Pond 3, the North Effluent Pond, the South Effluent Pond, and the West Coal Pile Runoff Ditch.
- **Selenium:** The distribution of selenium impacts is displayed on Figure 50. Sediment samples that exceeded the SCO were observed in the CPRO Ponds 3 through 7 and the North Effluent Pond.

Suspected off-property contaminants:

Investigation of potential impacts from smoke stack deposition has not occurred and suspected contaminants of concern off-property include, dioxins and furans (D/F), semi-volatile organic compounds (SVOCs) and select metals.

Documents reviewed:

2025-05-13 ECY Draft RI Report_TransAlta_Centralia.pdf

CONTAMINANT GROUP	CONTAMINANT	*SOIL*	*GROUNDWATER*	*SURFACE WATER*	*AIR*	*SEDIMENT*	DESCRIPTION
Non-Halogenated Organics	Phenolic Compounds	Select	Select	Select		Select	Compounds containing phenols (Examples: phenol; 4-methylphenol; 2-methylphenol)
	Non-Halogenated Solvents	Select	Select	Select	Select	Select	Organic solvents, typically volatile or semi-volatile, not containing any halogens. To determine if a product has halogens, search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is not a Cl, I, Br, F in the formula, it's not halogenated. (Examples: acetone, benzene, toluene, xylenes, methyl ethyl ketone, ethyl acetate, methanol, ethanol, isoproprano l, formic acid, acetic acid, stoddard solvent, Naptha). *Use this when TEX contaminants are present independently of gasoline.*
	Polynuclear Aromatic Hydrocarbons (PAH)	Select	**C**	Select	Select	Select	Hydrocarbons composed of two or more benzene rings.
	Tributyltin	Select	Select	Select		Select	The main active ingredients in biocides used to control a broad spectrum of organisms. Found in antifouling marine paint, antifungal action in textiles and industrial water systems. (Examples: Tributyltin; monobutyltin; dibutyltin)
	Methyl tertiary-butyl ether	Select	Select	Select	Select	Select	MTBE is a volatile oxygen-containing organic compound that was formerly used as a gasoline additive to promote complete combustion and help reduce air pollution.
	Benzene	Select	Select	Select	Select	Select	Benzene
	Other Non-Halogenated Organics	Select	Select	Select	Select	Select	TEX
	Petroleum Diesel	Select	**C**	Select		Select	Petroleum Diesel
	Petroleum Gasoline	Select	Select	Select	Select	Select	Petroleum Gasoline
	Petroleum Other	Select	**B**	Select		Select	Oil-range organics
Halogenated Organics (see notes at bottom)	PBDE	Select	Select	Select	Select	Select	Polybrominated di-phenyl ether
	Other Halogenated Organics	Select	Select	Select	Select	Select	Other organic compounds with halogens (chlorine, fluorine, bromine, iodine). search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is a Cl, I, Br, F in the formula, it is halogenated. (Examples: Hexachlorobutadiene; hexachlorobenzene; pentachlorophenol)
	Halogenated solvents	Select	**C**	Select	Select	Select	PCE, chloroform, EDB, EDC, MTBE
	Polychlorinated Biphenyls (PCB)	Select	Select	Select	Select	Select	Any of a family of industrial compounds produced by chlorination of biphenyl, noted primarily as an environmental pollutant that accumulates in animal tissue with resultant pathogenic and teratogenic effects
	Dioxin/dibenzofuran compounds (see notes at bottom)	**B**	Select	Select	Select	Select	A family of more than 70 compounds of chlorinated dioxins or furans. (Examples: Dioxin; Furan; Dioxin TEQ; PCDD; PCDF; TCDD; TCDF; OCDD; OCDF). *Do not use for 'dibenzofuran', which is a non-chlorinated compound that is detected using the semivolatile organics analysis 8270*
Metals	Metals – Other	**C**	**C**	Select		**C**	Cr, Se, Ag, Ba, Cd
	Lead	Select	Select	Select		Select	Lead
	Mercury	Select	Select	Select	Select	**C**	Mercury
	Arsenic	**C**	**C**	Select		Select	Arsenic
Pesticides	Non-halogenated pesticides	Select	Select	Select	Select	Select	Pesticides without halogens (Examples: parathion, malathion, diazinon, phosmet, carbaryl (sevin), fenoxycarb, aldicarb)
	Halogenated pesticides	Select	Select	Select	Select	Select	Pesticides with halogens (Examples: DDT; DDE; Chlordane; Heptachlor; alpha-beta and delta BHC; Aldrin; Endosulfan, dieldrin, endrin)

CONTAMINANT GROUP	CONTAMINANT	*SOIL*	*GROUNDWATER*	*SURFACE WATER*	*AIR*	*SEDIMENT*	DESCRIPTION
Other Contaminants	Radioactive Wastes	Select	Select	Select	Select	Select	Wastes that emit more than background levels of radiation.
	Conventional Contaminants, Organic	Select	Select	Select		Select	Unspecified organic matter that imposes an oxygen demand during its decomposition (Example: Total Organic Carbon)
	Conventional Contaminants, Inorganic	Select	Select	Select	Select	Select	Non-metallic inorganic substances or indicator parameters that may indicate the existence of contamination if present at unusual levels (Examples: Sulfides, ammonia)
	Asbestos	Select	Select	Select	Select	Select	All forms of Asbestos. Asbestos fibers have been used in products such as building materials, friction products and heat-resistant materials.
	Other Deleterious Substances	Select	Select	Select		Select	Other contaminants or substances that cause subtle or unexpected harm to sediments (Examples: Wood debris; garbage (e.g., dumped in sediments))
	Benthic Failures	Select	Select	Select		Select	Failures of the benthic analysis standards from the Sediment Management Standards.
	Bioassay Failures	Select	Select	Select		Select	For sediments, a failure to meet bioassay criteria from the Sediment Management Standards. For soils, a failure to meet TEE bioassay criteria for plant, animal or soil biota toxicity.
Reactive Wastes	Unexploded Ordinance	Select	Select	Select	Select	Select	Weapons that failed to detonate or discarded shells containing volatile material.
	Other Reactive Wastes	Select	Select	Select	Select	Select	Other Reactive Wastes (Examples: phosphorous, lithium metal, sodium metal)
	Corrosive Wastes	Select	Select	Select	Select	Select	Corrosive wastes are acidic or alkaline (basic) wastes that can readily corrode or dissolve materials they come into contact with. Wastes that are highly corrosive as defined by the Dangerous Waste Regulation (WAC 173-303-090(6)). (Examples: Hydrochloric acid; sulfuric acid; caustic soda)

(fill in contaminant matrix above with appropriate status choice from the key below the table)

Status choices for contaminants	
Contaminant Status	**Definition**
B— Below Cleanup Levels (Confirmed)	The contaminant was tested and found to be below cleanup levels. (Generally, we would not enter each and every contaminant that was tested; for example if an SVOC analysis was done we would not enter each SVOC with a status of "below". We would use this for contaminants that were believed likely to be present but were found to be below standards when tested
S— Suspected	The contaminant is suspected to be present; based on some knowledge about the history of the site, knowledge of regional contaminants, or based on other contaminants known to be present
C— Confirmed Above Cleanup Levels	The contaminant is confirmed to be present above any cleanup level. For example—above MTCA method A, B, or C; above Sediment Quality Standards; or above a presumed site-specific cleanup level (such as human health criteria for a sediment contaminant).
RA— Remediated - Above	The contaminant was remediated, but remains on site above the cleanup standards (for example—capped area).
RB— Remediated - Below	The contaminant was remediated, and no area of the site contains this contaminant above cleanup standards (for example—complete removal of contaminated soils).

Halogenated chemicals and solvents: Any chemical compound with chloro, bromo, iodo or fluoro is halogenated; those with eight or fewer carbons are generally solvents (e.g. halogenated methane, ethane, propane, butane, pentane, hexane, heptane or octane) and may also be used for or registered as pesticides or fumigants. Most are dangerous wastes, either listed or categorical. Organic compounds with more carbons are almost always halogenated pesticides or a contaminant or derivative. Referral to the HSDB is recommended if you are unfamiliar with a chemical name or compound, as it contains useful information about synonyms, uses, trade names, waste codes, and other regulatory information about most toxic or potentially toxic chemicals.

Dibenzodioxins and dibenzofurans are normalized to a combined equivalent toxicity based on 2,3,7,8-tetrachloro-p-dibenzodioxin as set out in WAC 173-340-708(8)(d) and in the Evaluating the Toxicity and Assessing the Carcinogenic Risk of Environmental Mixtures using Toxicity Equivalency Factors Focus Sheet (https://fortress.wa.gov/ecy/clarc/FocusSheets/tef.pdf). Results may be reported as individual compounds and isomers (usually lab results), or as a toxic equivalency value (reports).

FOR ECOLOGY II REVIEWER USE ONLY (For Listing Sites):

How did the Site come to be known ☒ **Site Discovery (received a report)** **5/14/2025** (Date Report Received)
☐ **ERTS Complaint**
☐ **Other (please explain):** Click to enter text.

Does an Early Notice Letter need to be sent: ☒ Yes ☐ No
If *No*, please explain why: Click to enter text.

NAICS Code (if known): **221112**
Otherwise, briefly explain how property is/was used (i.e., gas station, dry cleaner, paint shop, vacant land, etc.):
Power Generation Facility – Coal burning

Site Unit(s) to be created (Unit Type): ☒ Upland (includes VCP & LUST) ☒ Sediment
If multiple Unites needed, please explain why: Click to enter text.

Cleanup Process Type (for the Unit):
☐ No Process
☐ Voluntary Cleanup Program
☐ Federal-supervised or conducted
☐ Independent Action
☒ Ecology-supervised or conducted

Site Status:
☒ Awaiting Cleanup
☐ Cleanup Started
☐ No Further Action Required
☐ Construction Complete – Performance Monitoring
☐ Cleanup Complete – Active O&M/Monitoring

Model Remedy Used? ☐
If yes, was this a transformer spill? ☐

Site Manager (Default Tom Middleton) Click to enter text.

Specific confirmed contaminants include:
Metals in Soil
Metals, DRO, VOCs in Groundwater
Metals, in Other (specify matrix: Sediment

Facility/Site ID No. (if known):
94772166
Cleanup Site ID No. (if known):
Click to enter text.

COUNTY ASSESSOR INFO: Please attach to this report a copy of the tax parcel/ownership information for each parcel associated with the site, as well as a parcel map illustrating the parcel boundary and location.

Additional or Supplemental Information for Observations Page

Please use this box for any text that requires special formatting

Click to enter text.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-54:
Centralia Hazardous Substances Liability Determination (Oct. 2025)

COPY

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Southwest Region Office
PO Box 47775 • Olympia, WA 98504-7775 • 360-407-6300

Tuesday, October 14, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Final Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

On September 4, 2025, the Department of Ecology (Ecology) sent you written notice of our preliminary determination that TransAlta Centralia Generation LLC is a potentially liable person (PLP) for a release of hazardous substances at the Centralia Steam Plant facility (Site). On October 8, 2025, Ecology received your written notice accepting your status as a PLP for the Site and waiving your opportunity to comment.

Based on available information, Ecology finds that credible evidence exists that TransAlta Generation LLC is liable for a release of hazardous substances at the Site. On the basis of this finding, Ecology has determined that TranAlta Generation LLC is a PLP with regard to the Site.

The purpose of the Model Toxics Control Act (MTCA) is to identify, investigate, and cleanup facilities where hazardous substances have been released. Liability for environmental contamination under MTCA is strict, joint and several (RCW 70.105D.040(2)). Ecology ensures that contaminated sites are investigated and cleaned up to the standards set forth in the MTCA statue and regulations. Ecology has determined that it is in the public interest for remedial actions to take place at this Site. Ecology will contact you regarding the actions necessary for the TransAlta Generation LLC to bring about the prompt and thorough cleanup of hazardous substances at this Site. Failure to cooperate with Ecology or comply with MTCA in this matter will result in Ecology employing enforcement tools as it deems necessary and appropriate. This includes, but is not limited to, the issuance of an administrative order. Failure to comply with such an order may result in a fine of up to $25,000 per day and liability for up to three times the costs incurred by the state (RCW 70.105D.050(1)).

Your rights and responsibilities as a PLP are outlined in Chapter 70.105D RCW, and Chapters 173-340 and 173-204 WAC. Ecology's cleanup project manager for the Site, Thomas Middleton, will contact you with information about how Ecology intends to proceed with the cleanup.

If you have any questions regarding this notice, please contact Thomas Middleton at (360) 999-9594 or Thomas.middleton@ecy.wa.gov.

Sincerely,

Marian L. Abbett

Marian Abbett
Section Manager
Toxics Cleanup Program, SWRO

By certified mail:9489 0090 0027 6341 0494 07

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General: dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Tom Middleton, SWRO TCP Cleanup Project Manager: thomas.middleton@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-55:
Emissions Performance Standard

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Emissions Performance Standard (EPS)

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Energy Policy, Standards and Reports

Energy Policy, Standards and Report: Electricity Policy and Standard:

Emissions Performance Standard (EPS)

The emissions performance standard (EPS) is a set of state-imposed rules to a limit the amount of CO2 that each power station may emit to atmosphere.

The emissions performance standard (EPS) is a set of state-impose rules to limit the amount of greenhouse gas emissions each baseload power plant can release into the air.

Every five years, our office adopts rules on the average available greenhouse gas emissions output by surveying new combined-cycle natural gas thermal electric generation turbines. The turbines need to be commercially available, offered for sale by manufacturers and purchased in the United States. Then we determine the average rate of emissions of greenhouse gases for them.

Baseload generation limits and utility investment restrictions

Baseload generation, which refers to the minimum amount of continuous electricity supply that is needed to meet the basic demand of the power grid over a 24-hour period, is considered to be a generating unit operating at a capacity factor of 60 or greater percent. This means a facility that produces energy each year equaling at least 60 percent of the energy it could produce at continuous full power operation for the same period.

Utilities may not enter into long-term contracts (five or more years) with a baseload generating facility, nor can utilities invest in a facility, when the greenhouse gas emissions of the facility exceed the standard.

The standard applies to all investor and consumer-owned utilities in the state. Renewable and nuclear-powered electricity are exempt, as are long-term commitments with the Bonneville Power Administration.

The performance standard was last updated in January 2025. The new rule lowers the average estimated greenhouse gas emissions rate of combined-cycle natural gas power plants from 925 to 876 pounds per megawatt-hour. This updated emissions rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to

Feedback

apply Washington's emissions standard as required by state law (**Chapter 80.80 RCW**).

Power plants must meet the greenhouse gas emission standards or capture and store their carbon pollution under this rule. The Department of Ecology and local clean air agencies regulate small plants that generate megawatts of electricity (MWe), but less than 350 MWe. The Energy Facility Site Evaluation Council (EFSEC) regulates larger plants that generate more than 350 MWe.

Rulemaking

Commerce began its most recent rulemaking process in February 2024, and since then, the agency held three public workshops and three technical advisory group meetings. Commerce received and responded to comments, incorporating changes based on them into the rulemaking process. The public workshops and advisory team meetings were well-attended. Commerce received two public comments.

The latest rule lowers the average available greenhouse gas emissions output estimate of combined-cycle natural gas facilities from 925 lb/MWh to 876 lb/MWh. The updated average rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to implement Washington's baseload electric generation emissions performance standard as provided for under **Chapter 80.80 RCW**.

- **Final rules for WAC 194-26-020**

For questions related to the rulemaking process, please contact Aaron Tam, Energy Utility Data Specialist, at **energydata@commerce.wa.gov** or by calling 206-454-2251.

Resources

- **Final rules for WAC 194-26-020**
- **RCW 80.80.040**
- **WAC 194.26.010 – Authority**
- **WAC 194.26.020 – Average available greenhouse gas emissions output**
- **Department of Ecology's power plant greenhouse gas standards webpage**

Feedback

Page last updated:May 21, 2025

Contact

Austin Scharff, Senior Energy Policy Specialist
Austin.Scharff@commerce.wa.gov

Aaron Tam, Data Specialist
Aaron.Tam@commerce.wa.gov

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Washington State Department of Commerce

Feedback

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-56:
Puget 2024 Annual EEI Report

PUGET SOUND ENERGY

Annual Energy and Emissions Intensity ("EEI") Metrics Report

Pursuant to WAC 480-109-300

May 31, 2025

Table of Contents

PSE's Annual Energy and Emissions Intensity (EEI) Metrics Report for operating year 2024

Section 1: Executive Summary

Compared to the 2023 operating year, Puget Sound Energy's (PSE's) 2024 carbon dioxide equivalent (CO_2e) emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh to 830.3 lb/MWh.[1] This report provides the metrics, analyses, and descriptions behind that change. Further, it demonstrates that PSE delivers electricity to customers from a combination of sources that the Company owns and purchases from other providers via firm contracts or the spot market.

Per the requirements of WAC 480-109-300, PSE submits the following report outlining its energy and emissions intensity metrics for the previous ten years (reporting period). This report includes the following metrics for all PSE generating resources serving customers:

- Average megawatt-hours (aMWh) per residential customer
- Average megawatt-hours (aMWh) per commercial customer
- Megawatt-hours (MWh) per capita
- Annual carbon dioxide equivalent (CO_2e) emissions measured in metric tons
- Comparison of annual CO_2e emissions to CO_2 emissions in 1990

PSE and the other utilities purchase a percentage of their energy to serve native load from the spot market. The generation sources from purchases made on the spot market are unknown. Therefore, this report also includes a subset of metrics for spot market purchases based on the unspecified emission rate factor provided by the Washington State Department of Ecology ("Ecology"). Those metrics include:

- Annual CO_2e emissions (metric tons) from unknown generation sources
- Annual megawatt-hours (MWh) delivered to retail customers from unknown generation sources
- Percentage of load served by unknown generation sources

In addition to the raw data included in Attachment A to this report, the tables and sections below provide trend analysis, narrative descriptions, and graphics to help contextualize PSE's data and trends for the reporting period. Table 1 below summarizes PSE's greenhouse gas

[1] Beginning in 2022, adjusted to apply Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors for BPA specified purchases. See Sections 3 and 4 for more information.

(GHG) emissions intensity and energy metrics for the calendar year 2024. Summaries of the previous nine years in the reporting period are included in Attachment A to this report. Section 2 below provides a 10-year "lookback" analysis of the reporting period (to the operating year 2015) of the metrics mentioned above and benchmarks those metrics to a 1990 emissions baseline. Section 3 provides a discussion of the trends observed in the metrics and the broader regional market. Section 4 includes appendices that provide more detail on the methodologies used in this report.

Summarized in Table 1 and narrative below are PSE's 2024 energy and emissions intensity metrics. The energy intensity metrics represent the metered sale of energy to customers (by class) as reported under the Federal Energy Regulatory Commission (FERC) Form-1 protocols, i.e., Total Load Served. Busbar energy tallies represent the total load PSE served (to Washington) generated and purchased, net of bilateral sales, as reported in PSE's Energy Accounting (EA) database, i.e., Busbar MWh.

Table 1. 2024 Energy and Intensity Metrics

Utility :	Puget Sound Energy	
Reporting for year :	2024	**MWh per Capita**
Population Served :	2,712,488	**7.80**

Energy Intensity Metrics

	MWh at Meter	MWh Proportion	Customer Count	**MWh per Customer**
Residential Customers	11,462,977	54.2%	1,091,599	**10.5**
Commercial Customers	8,570,573	40.5%	134,993	**63.5**
Industrial Customers	1,057,368	5.0%		
Other Customers	77,822	0.4%		
Total Load Served	21,168,740	100.0%		

Emissions Intensity Metrics

	Busbar MWh	Percent of Total Load	**Metric Tons CO_2e**	
Known Resources Serving WA				
EPA Methodology	25,508,769	114.9%	9,623,768	
EIA Methodology	0	0.0%	0	
Unknown Resources Serving WA	(3,299,563)	**-14.9%**	(1,259,530)	**% of 1990 CO_2**
Total Busbar MWh	**22,209,206**	Total Metric Tons:	**8,364,238**	**132.7%**

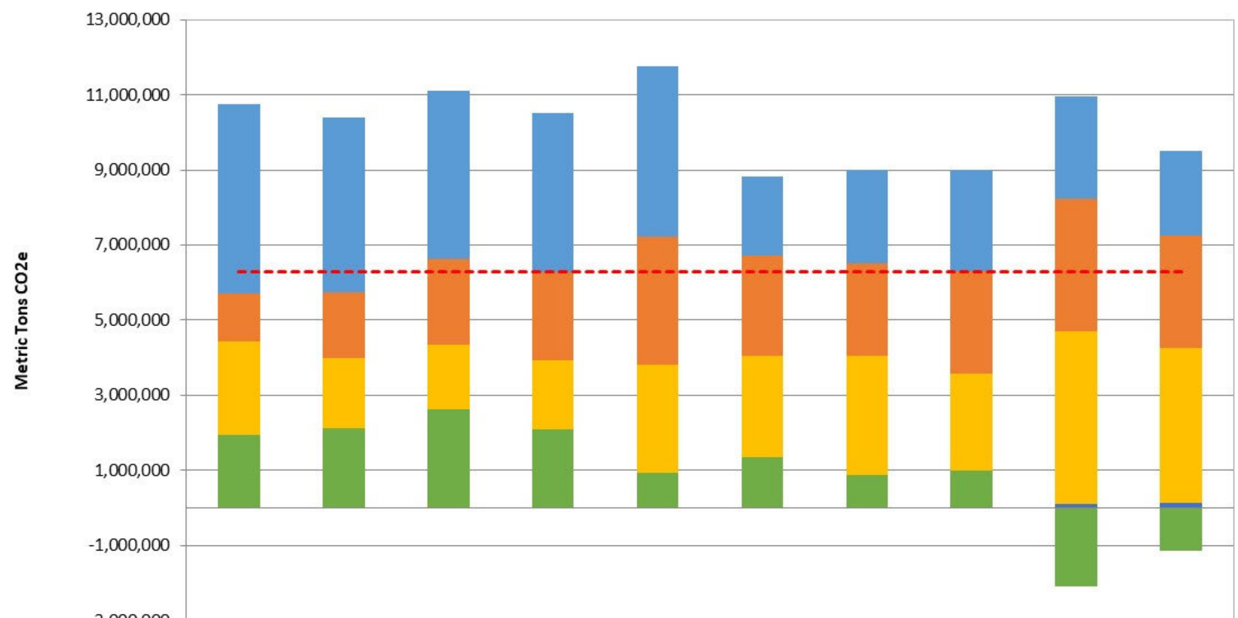
1990 Metric Tons CO_2	6,301,363

Section 2: Prior 10-year annual metrics for all generating resources serving Washington customers

Figure 1 provides a comparison of annual PSE CO_2e emissions measured in metric tons from generation sources for the previous 10 years. Figure 1 also includes a 1990 emissions baseline.

Until 2020, WAC 480-109-300 specified that the EEI report only include CO_2 output. In 2020, as a result of rulemaking conducted to implement the Clean Energy Transformation Act (CETA), revised WAC 480-109-300 now requires all greenhouse gas emissions in the EEI report be based on CO_2e. This change means the inclusion of methane (CH4) and nitrous oxide (N2O) as CO_2e[2] for all resources and years presented in this report.

Figure 1. Total Emissions by Resource Type

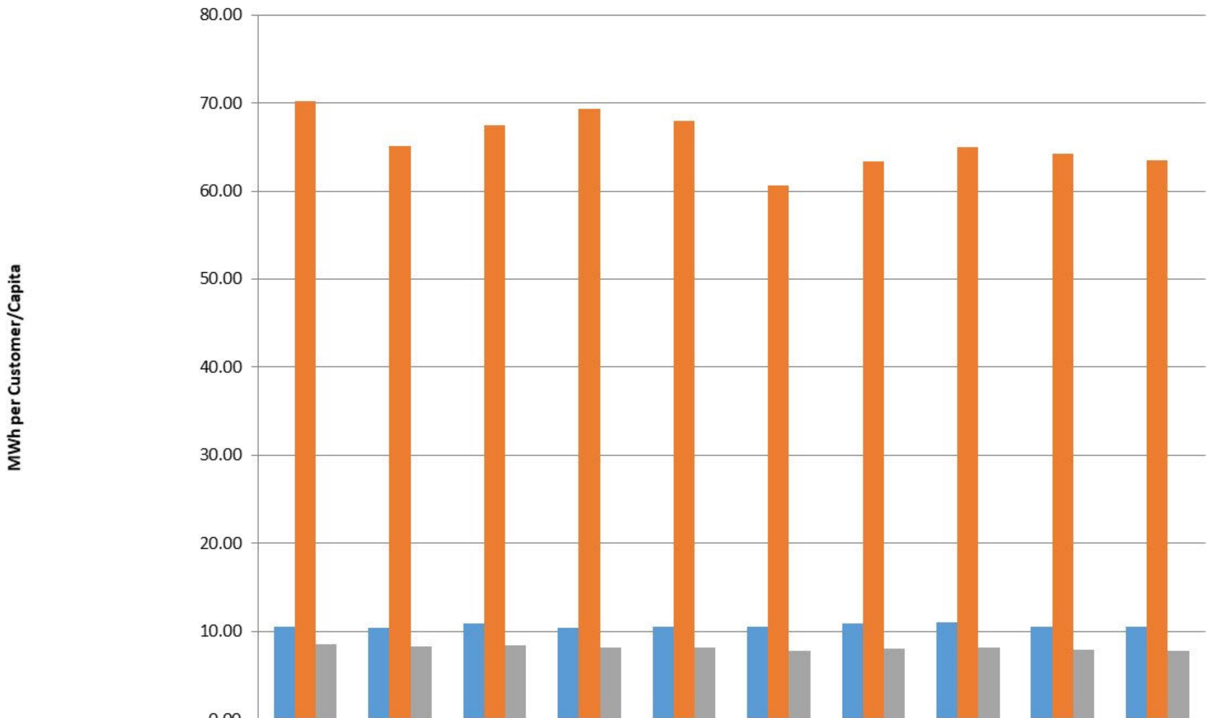


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Owned Coal	5,034,544	4,642,921	4,486,832	4,255,201	4,531,772	2,089,805	2,508,424	2,684,409	2,741,750	2,230,496
Firm Coal	1,280,440	1,746,188	2,271,968	2,348,792	3,395,867	2,671,660	2,459,358	2,750,063	3,536,340	3,015,251
Owned Diesel	253	155	335	62	155	514	439	747	34	305
Owned Gas	2,487,336	1,872,826	1,730,673	1,825,412	2,874,183	2,703,673	3,170,392	2,566,071	4,578,453	4,118,746
Firm Gas	167	86							113,329	131,152
Unspecified	1,935,514	2,119,604	2,625,679	2,097,895	950,430	1,348,716	873,099	999,377	-2,100,695	-1,131,712
1990 Baseline	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363

[2] Principle combustible constituents in natural gas and coal are carbon, hydrogen, and their compounds, and in the combustion process, these compounds and elements oxidize to CO_2 and water vapor. However, small amounts of methane (CH_4) result from incomplete fuel combustion, and nitrous oxide (N_2O) formation results from post-combustion thermal reactions.

Figure 2 provides a comparison of the average MWh per residential customer, average MWh per commercial customer, and MWh per capita delivered in each of the years during the reporting period in PSE's service territory.

Figure 2. Energy Intensity Metrics



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MWh / Residential Customer	10.47	10.40	10.89	10.39	10.49	10.56	10.90	11.03	10.57	10.50
MWh / Commercial Customer	70.25	65.07	67.49	69.33	68.01	60.66	63.37	64.99	64.28	63.49
MWh per capita	8.48	8.29	8.41	8.18	8.15	7.75	8.04	8.17	7.91	7.80

Figure 3 provides a comparison of the ratios of PSE's annual CO_2e emissions from known sources for the reporting period compared to CO_2 emission in 1990.

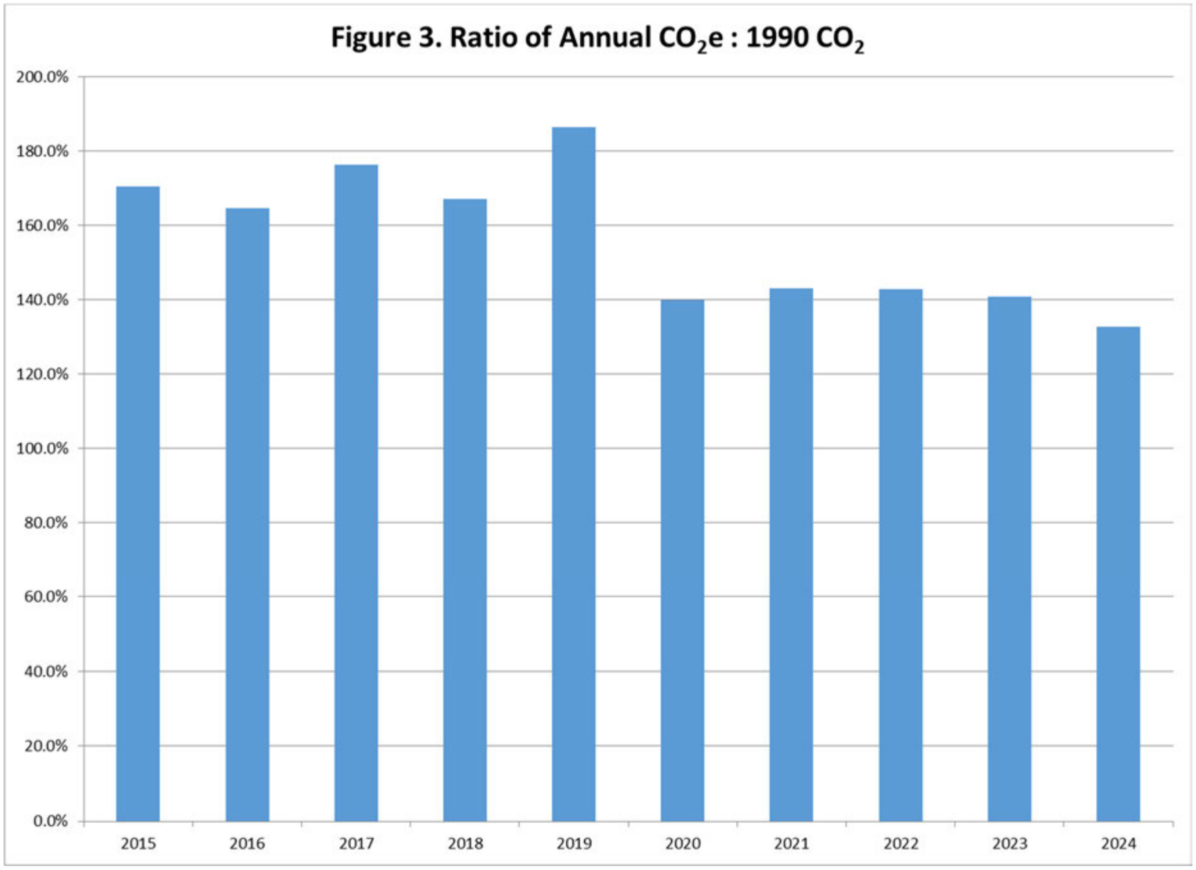
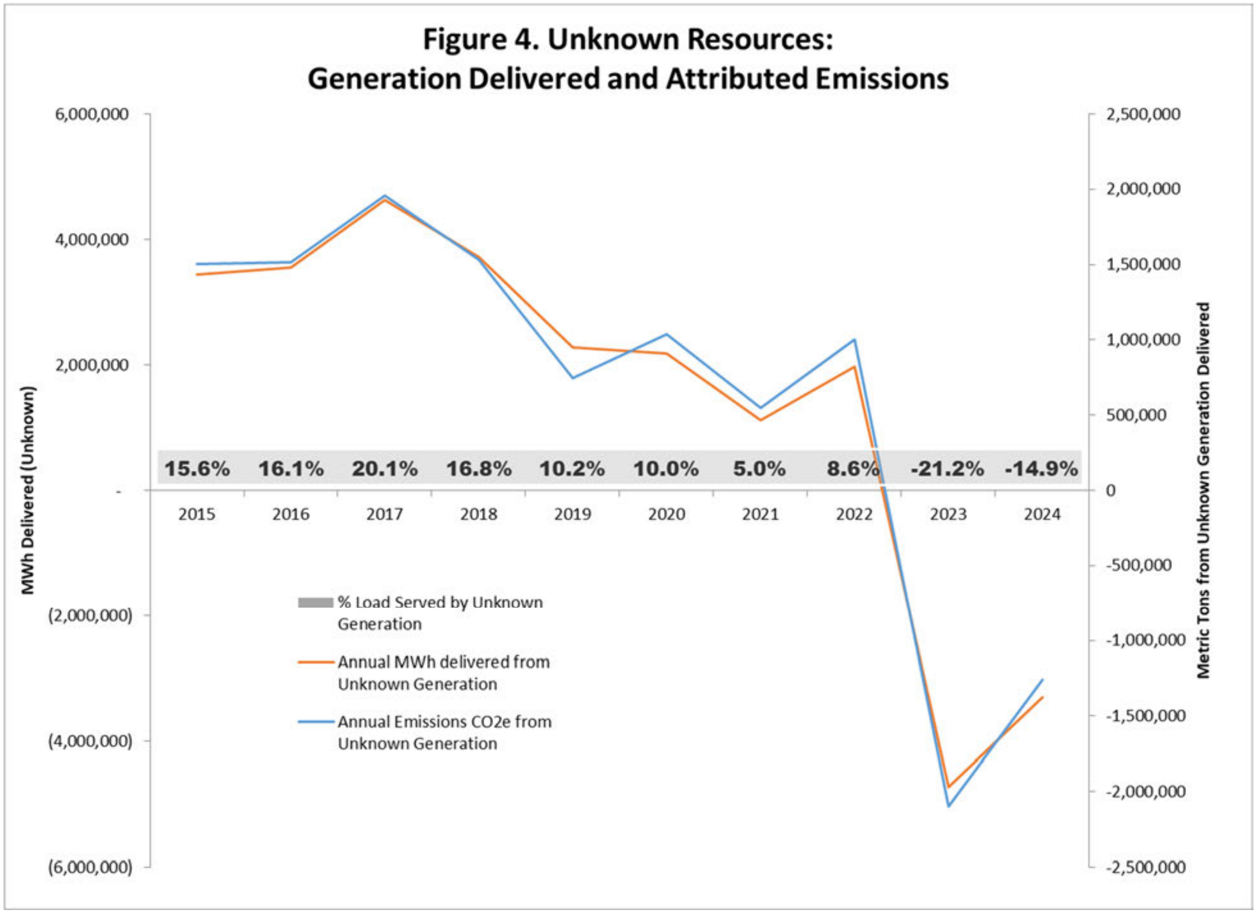


Figure 4 provides a 10-year comparison of generation delivered to PSE from unknown sources and the attributed emissions. Those metrics include annual CO_2e emissions (metric tons), annual MWh delivered to retail customers, and the percentage of load served. As discussed in the executive summary, the generation sources and attributed emissions for spot market purchases are unknown. Therefore, emissions factors for each of the previous ten years in the reporting period were applied according to methodology provided by the Department of Ecology.



Section 3: Trend Analysis

This section addresses the requirement in WAC 480-109-300(5) to include narrative text describing trends and an analysis of the likely causes of changes, or lack of changes, in the metrics.

Electric Supply

In 2024, PSE's electric power resources, which include company-owned or controlled resources and those under long-term contract, had a total capacity of approximately 6,524 megawatts (MW). PSE purchases electric energy under long-term firm-purchased power contracts with other utilities and marketers in the Western Interconnection. PSE is generally not obligated to make payments under these contracts unless power is delivered.

Energy supply and demand balance across the Western Interconnection is maintained on a second-to-second basis, and PSE dispatches its resources based on market prices and other system constraints in the Interconnection. Generally speaking, when the dispatch cost of a specific PSE-owned unit is lower than the market price, it is economic for the unit to run. Net revenue resulting from sales of electricity from PSE-dispatched resources result in net revenue that is credited back to customers to reduce rates. When the cost to run the PSE-owned unit is greater than the market price, the units are not dispatched. PSE may also dispatch resources in real-time based on dispatch operating instructions issued by the California Independent System Operator (CAISO) in its Energy Imbalance Market (EIM). Dispatch decisions are independent of the demand by PSE's customers. If PSE's customers need power when its units are uneconomic to run, PSE purchases the energy from wholesale markets – other utilities or registered power marketers with energy to sell. If PSE's generation is dispatched and there is a surplus above PSE's customers' needs, that surplus will be sold in the wholesale market (net revenue from such sales is credited back to customers through rates), meaning whatever is happening to PSE's load is unrelated. The primary driver of generation dispatch is whether a generator's variable cost of dispatch is lower than the market price.

PSE tracks its firm and non-firm power transactions in its Energy Accounting (EA) database on a calendar year basis. Table 2 shows all firm energy transactions made in 2024, including the total dispatch of all of PSE-owned units. Emissions from PSE's units and from each firm purchase are calculated using the methodologies described in Appendix 2.1 and 2.2, respectively. For unspecified electricity purchases, PSE uses the emissions intensity metrics according to WAC

480-109-300(4)[3]. PSE employed Commission Staff's net-by-counterparty approach to calculate emissions from its non-firm (unspecified) power transactions. Details of these transactions are presented in Table 3, and the calculation methodology is described in Appendix 2.3. Staff requested in its compliance letter to PSE's 2017 EEI report that the Company explain how PSE determines whether a source is known or unknown. Staff correctly assumes that PSE classifies non-unit specific purchases as unknown sources. PSE-owned resources and unit-specific firm deliveries are classified as known sources because their fuel source is known and reported in the U.S. Energy Information Administration (EIA) databases, described in Appendix 2.1 and 2.2.

Table 2. Known Resources Serving WA Customers

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Lower Baker	326,698		0	Own	Hydro
Snoqualmie Falls #1	65,857		0	Own	Hydro
Snoqualmie Falls #2	158,872		0	Own	Hydro
Upper Baker	317,830		0	Own	Hydro
Colstrip 3 & 4	2,195,159		2,230,496	Own	Coal
Crystal Mountain	366.2		305	Own	Diesel
Encogen	763,946		364,444	Own	Gas
Ferndale	1,684,142		804,020	Own	Gas
Freddie #1	856,249		333,786	Own	Gas
Fredonia	555,781		367,670	Own	Gas
Frederickson	88,924		63,613	Own	Gas
Goldendale	2,099,550		780,985	Own	Gas
Mint Farm	2,695,425		924,443	Own	Gas
Sumas	674,253		316,436	Own	Gas
Whitehorn	230,887		163,349	Own	Gas
Hopkins Ridge (W184)	411,010		0	Own	Wind
Lower Snake River	873,275		0	Own	Wind
Wild Horse (W183)	636,124		0	Own	Wind
Sierra Pacific Industries	128,427		0	Bundled PPA	Biomass
Bio Energy Washington (BEW)	77		0	Qualifying Facility	Biogas

[3] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Edaleen Dairy LLC	3,508		0	Qualifying Facility	Biogas
Emerald City Renewables	32,053		0	Qualifying Facility	Biogas
Farm Power Rexville LLC	3,099		0	Qualifying Facility	Biogas
Rainier Bio Gas	832		0	Qualifying Facility	Biogas
VanderHaak Dairy Digester	2,451		0	Qualifying Facility	Biogas
Transalta Centralia Generation LLC	2,700,452		3,015,251	Unbundled PPA	Coal
Transalta Centralia Generation LLC	292,490		127,818	Unbundled PPA	Market
Chelan County PUD #1	123,200		0	Bundled PPA	Hydro
Chelan PUD - RI & RR	1,632,424		0	Bundled PPA	Hydro
Chelan PUD - Slice 35	323,790		0	Bundled PPA	Hydro
Chelan PUD - Slice 38	334,072		0	Bundled PPA	Hydro
Black Creek Hydro Inc	11,311		0	Qualifying Facility	Hydro
Koma Kulshan Associates	24,725		0	Qualifying Facility	Hydro
Nooksack	20,084		0	Qualifying Facility	Hydro
Skookumchuck Hydro	2,157		0	Qualifying Facility	Hydro
Sygitowicz Creek	594		0	Qualifying Facility	Hydro
Twin Falls Hydro	62,947		0	Qualifying Facility	Hydro
Weeks Falls	11,521		0	Qualifying Facility	Hydro
Douglas PUD - Wells Project	535,293		0	Unbundled PPA	Hydro
Grant PUD - Priest Rapids Project	336,069		0	Unbundled PPA	Hydro
KERR DAM-ENERGY KEEPER	351,282		0	Unbundled PPA	Hydro
Powerex Seasonal Capacity	1,216,000		0	Unbundled PPA	Hydro
HF Sinclair (Mar Pt)	656,794		223,636	Qualifying Facility	Gas
CAMAS SOLAR	9,844		0	Community Solar	Solar
Penstemon Solar	10,843		0	Community Solar	Solar
URTICA SOLAR	10,646		0	Community Solar	Solar
Bonney Lake CS	514		0	CS Generation	Solar
Olympia High School CS	245		0	CS Generation	Solar
Pine Lake Middle School CS	145		0	CS Generation	Solar
Lund Hill Solar, LLC	361,485		0	Green Direct	Solar
CC Solar 1 and CC Solar 2	28		0	Qualifying Facility	Solar

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Ikea Solar	13		0	Qualifying Facility	Solar
Lake Washington -- Finn Hill	287		0	Qualifying Facility	Solar
Port of Coupeville	49		0	Qualifying Facility	Solar
Schedule 667 Solar Energy Credit	168		0	Qualifying Facility	Solar
TACOMA GLASS	174		0	Qualifying Facility	Solar
Avangrid Renewable (Golden Hills)	685,096		0	Bundled PPA	Wind
Clearwater Wind	1,304,894		0	Bundled PPA	Wind
Klondike Wind Power III	123,482		0	Bundled PPA	Wind
Skookumchuck Wind PPA	416,933		0	Green Direct	Wind
Swauk Wind	2,363		0	Green Power Program	Wind
California ISO		-374,270	0	EIM Sales and Purchases	Hydro
California ISO		-212,412	-92,484	EIM Sales and Purchases	Gas
California ISO		-271,754	0	EIM Sales and Purchases	Wind

Table 3. Unknown Resources Serving WA Customers

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
BPA Purchases	Market	792,762	0	792,762	--	208,238.7
BPA Sales	Market	0	-358,111	-358,111	--[4]	-156,495
Avista Corp. WWP Division	Market	14,754	-76,585	-61,831	0.377	-23,327
Avista Nichols Pump	Interchange In	13,837	0	13,837	0.437	6,046.8
BASIN ELECTRIC POWER	Market	0	-4,022	-4,022	0.377	-1,517
BC Hydro (Point Roberts)	Unbundled PPA	20,596	0	20,596	0.437	9,000.4
BHE Power Watch, LLC	Market	0	-3	-3	0.377	-1
BP Energy Co.	Market	1,805	-547,122	-545,317	0.377	-205,733
British Columbia Transmission Corp	Market	0	-8	-8	0.377	-3
Brookfield Energy Marketing	Market	61,600	-242,601	-181,001	0.377	-68,287

[4] BPA specified purchases use 0.0174; BPA unspecified purchases use 0.437.

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
California ISO	EIM Purchases	1,230,919	0	1,230,919	0.437	537,911.7
California ISO	EIM Sales	0	-37,873	-37,873	0.377	-14,288
California ISO	EIM Sales to CA	0	-173	-173	0.377	-65
California ISO	Purchases	108,868	0	108,868	0.437	47,575.3
California ISO	Sales	0	0	0	0.377	-0.1
California ISO	Sales to CA	0	-2,244	-2,244	0.377	-847
Chelan County PUD #1	Market	19,602	-3,606	15,996	0.437	6,990.3
Citigroup Energy Inc	Market	47,676	-773,028	-725,352	0.377	-273,656
Clatskanie PUD	Market	2,671	-3,322	-651	0.377	-246
Conoco, Inc.	Market	809,406	-594,187	215,219	0.437	94,050.7
CONSTELLATION ENERGY	Market	53,713	-58,364	-4,651	0.377	-1,755
CP Energy Marketing (Epcor)	Market	6,209	-6,572	-363	0.377	-137
Deviation	System Deviation	0	-3,994	-3,994	0.377	-1,507
DYNASTY POWER INC	Market	597	-312,664	-312,067	0.377	-117,734
EDF Trading NA LLC	Market	22,537	-6,288	16,249	0.437	7,100.8
Energy Keepers Inc.	Market	400	-1,000	-600	0.377	-226
Eugene Water & Electric	Market	7,736	-40,653	-32,917	0.377	-12,419
Grant County PUD #2	Market	6	0	6	0.437	2.6
GRIDFORCE ENERGY MANAGEMENT, LLC.	Market	10	-761	-751	0.377	-283
Iberdrola Renewables (PPM Energy)	Market	268,684	-802,903	-534,219	0.377	-201,546
Idaho Power Company	Market	5,669	-9,479	-3,810	0.377	-1,437
J. Aron & Company	Market	0	-400	-400	0.377	-151
MERCURIA ENERGY	Market	20,852	-228,460	-207,608	0.377	-78,325
Merrill Lynch Commodities	Market	354,833	-790,692	-435,859	0.377	-164,438
Morgan Stanley CG	Market	320,484	-351,762	-31,278	0.377	-11,800
Natur Ener USA	Market	0	-20	-20	0.377	-8
Nevada Energy	Market	0	0	0	0.377	0.0
Nevada Power Company	Market	50	-155	-105	0.377	-40
New Mexico, Public Service Company	Market	90	0	90	0.437	39.3
Northwestern Energy	Market	6,944	-23,827	-16,883	0.377	-6,369
NRG Business Marketing LLC DECM	Market	0	-400	-400	0.377	-151
Pacific Gas & Elec - Exchange	Interchange In-Out	413,000	-413,000	0	0.377	0.0

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
Pacificorp	Market	8,216	-57,809	-49,593	0.377	-18,710
PHILLIPS 66 ENERGY	Market	7,194	-268,574	-261,380	0.377	-98,612
Portland General Electric	Market	24,398	-149,315	-124,917	0.377	-47,128
Powerex Corp.	Market	46,199	-965,399	-919,200	0.377	-346,789
Rainbow Energy Marketing	Market	2,137	-4,796	-2,659	0.377	-1,003
Sacramento Municipal	Market	50	-60	-10	0.377	-4
Salt River Project Power	Market	6	-5	1	0.437	0.4
Seattle City Light Marketing	Market	27,681	-51,598	-23,917	0.377	-9,023
Shell Energy (Coral Pwr)	Market	109,261	-160,998	-51,737	0.377	-19,519
Snohomish County PUD #1	Market	7,005	-24,295	-17,290	0.377	-6,523
Tacoma Power	Market	14,683	-4,292	10,391	0.437	4,540.9
The Energy Authority	Market	26,603	-127,731	-101,128	0.377	-38,153
TransAlta Energy Marketing	Market	447,332	-1,097,517	-650,185	0.377	-245,297
TransCanada Energy Sales Ltd	Market	176	-9,679	-9,503	0.377	-3,585
Turlock Irrigation District	Market	988	0	988	0.437	431.8
Vitol Inc.	Market	33,504	-44,959	-11,455	0.377	-4,322

Columbia River Energy Supply Contracts

During 2024, approximately 14.8 percent of PSE's energy supply requirement was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River (Mid-Columbia). PSE's portion of the power output of the PUD projects is shown in Table 4.

Table 4. Columbia River Electric Energy Supply Contracts

Project	Contract Expiration	Percent of Output (PSE Share)	MW Capacity (PSE Share, approx.)
Rock Island Project (Chelan County PUD)	2031	25%	156
Rocky Reach Project (Chelan County PUD)	2031	25%	325
Wells Project (Douglas County PUD)	2028	27.1%	228
Priest Rapids Development (Grant County PUD)	2052	0.6%	6
Wanapum Development (Grant County PUD)	2052	0.6%	7

2024 Carbon Dioxide Emissions - Results & Discussion

Overall, PSE's CO_2e emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh in 2023 to 830.3 lb/MWh in 2024 (as seen in Table 6). As shown in Table 5, in 2024, 65.9 percent of electricity delivered to PSE customers was generated by the company, 34.1 percent of electricity was purchased via firm contracts (49.0 percent) and non-firm contracts, i.e., spot market (-14.9 percent)[5]. Of the CO_2e emissions associated with electric delivery, 75.9 percent were from electricity generated by PSE, and 24.1 percent were from purchased electricity (39.1 percent via firm contracts and -15.1 percent via non-firm contracts).

It is important to remember that CO_2e emissions vary based on the fuel source or technology used to generate the electricity. Some sources are more emissions intense than others. "Intensity" is the relationship between emissions and production, and utilities can measure that intensity using a metric called pounds of CO_2e per megawatt-hour (lb/MWh) of electricity produced. For instance, in 2024 (as seen in Table 5), about 15.0 percent of the electricity generated by PSE came from coal combustion, but this fuel source represented about 35.1 percent of the CO_2e emissions from electricity generated by PSE. Natural gas accounted for 65.9 percent of the electricity generated by PSE; however, this fuel source represented 64.9 percent of the CO_2e emissions from electricity generated by PSE. Renewable energy accounted for 19.1 percent of the electricity generated by PSE-owned generation resources and produced zero CO_2e emissions.

Compared to 2023 (as seen in Table 7), total electricity delivered to customers in 2024 decreased slightly, by 0.3 percent, and total emissions decreased slightly, by 5.7 percent. This trend is due primarily to a decrease in PSE coal generation and purchases. Coal generation decreased significantly, by 18.4% in 2024 compared to 2023, which resulted in 1.1 MM metric tons of fewer emissions compared to the previous year.

[5] This is net of all unspecified purchases.

Table 5. Summary of Total Energy Delivered (MWh) and Total Emissions (metric ton CO_2e)

2024	Total Energy Delivered (MWh)				Total Emissions (CO_2e)			
Source	MWh Total	MWh % of PSE All-owned Total	MWh % of PSE Thermal Only	MWh % of Total	Metric Ton Total	Metric Ton % of PSE All-owned Total	Metric Ton % of PSE Thermal Only	Metric Ton % of Total
PSE Owned Coal	2,195,159	15.0%	18.5%	9.9%	2,230,496	35.1%	35.1%	26.7%
PSE Owned Gas	9,649,521	65.9%	81.5%	43.4%	4,119,051	64.9%	64.9%	49.2%
PSE Owned Renewable	2,789,666	19.1%		12.6%	0	0.0%		0.0%
Firm Coal	2,700,452			12.2%	3,015,251			36.0%
Firm All Other	8,173,971			36.8%	258,970			3.1%
Unspecified	-3,299,563			-14.9%	-1,259,530			-15.1%
Total (from energy)	22,209,206				8,364,238			
PSE Own plus Firm PPA	25,508,769				9,623,768			
Total PSE Only	14,634,346			65.9%	6,349,547			75.9%
Total Firm Only	10,874,423			49.0%	3,274,221			39.1%
Total Unspecified Only	-3,299,563			-14.9%	-1,259,530			-15.1%

Table 6. 2023 and 2024 Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024					*2023*				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	2,195,159	9.9%	2,230,496	26.7%	2,240.1	3,326,355	15%	2,741,750	31%	1,817.2
Firm Coal	2,700,452	12 2%	3,015,251	36 0%	2,461.6	2,673,671	12%	3,536,340	40%	2,916.0
PSE Owned Gas	9,649,521	43.4%	4,119,051	49 2%	941.1	9,954,456	45%	4,578,487	52%	1,014.0
PSE Owned All Other	2,789,666	12.6%	0	0.0%	0.0	2,265,369	10%	0	0%	0.0
Firm All Other	8,173,971	36 8%	258,970	3.1%	69.8	8,794,954	39%	113,329	1%	28.4
Unspecified	-3,299,563	-14 9%	-1,259,530	-15.1%	841.6	-4,732,543	-21%	-2,100,695	-24%	978.6
PSE Owned Plus Firm PPA	25,508,769		9,623,768		831.7	27,014,805		10,969,906		895.2
PSE Owned	14,634,346	65 9%	6,349,547	75 9%	956.5	15,546,180	69.8%	7,320,237	82.5%	1,038.1
Firm	10,874,423	48.96%	3,274,221	39.1%	663.8	11,468,625	51.5%	3,649,669	41.1%	701.6
Unspecified	-3,299,563	-14.86%	-1,259,530	-15.1%	841.6	-4,732,543	-21.2%	-2,100,695	-23.7%	978.6
Total (Own, Firm, Unspecified)	22,209,206		8,364,238		830.3	22,282,262		8,869,210		877.5

Table 7. Comparison to Previous Year: Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024 vs. 2023				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	-1,131,196	-34.0%	-511,254	-18.6%	423.0
Firm Coal	26,781	1.0%	-521,088	-14.7%	-454.3
PSE Owned Gas	-304,935	-3.1%	-459,436	-10.0%	-72.9
PSE Owned All Other	524,296	23.1%	0	0.0%	0.0
Firm All Other	-620,983	-7.1%	145,641	0.0%	41.4
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
PSE Owned	-911,834	-5.9%	-970,690	-13.3%	-81.6
Firm	-594,202	-5.2%	-375,447	-10.3%	-37.8
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
Total (Own, Firm Unspecified)	-73,056	-0.3%	-504,972	-5.7%	-47.2

Trends Discussion

The relative amount of GHG emissions from the electricity sources did not align with the amount of power produced from each electricity source. This trend is due to factors related to the intensity of emissions from each source, which reflects the relationship between CO_2e and power production of each source.

For example, about 15.0 percent of the electricity generated by PSE came from coal combustion, which has a high CO_2e emission intensity compared to natural gas and oil combustion sources. Of CO_2e emissions from electricity generated by PSE (direct emissions), about 35.1 percent were from coal-combustion generation. The high CO_2e emission intensity of coal-combustion generation made the overall CO_2e emission intensity of PSE's electric operations high.

Another example highlighting this trend occurs in purchased electricity. Roughly 74.3 percent[6] of firm contract electricity purchased by PSE came from renewable plants in the Pacific Northwest (primarily hydroelectric), while the remaining purchases were sourced from thermal plants. Since hydroelectric generation is considered a non-GHG emitting source, almost all of the CO_2e emissions generated from firm contract purchased electricity come from coal and natural gas generated electric operations.

A third example relates to how emissions are calculated for electricity purchased by PSE on the spot market (i.e., non-firm contracted electricity purchases). Again, these purchases are sourced from different utilities and non-utilities via the "grid" system of electric distribution, making the source of energy challenging to track and measure. Therefore, regional average emission factors were used to estimate non-firm contract purchased electricity. For instance, electricity purchased by a utility from an energy trader could have been purchased by the energy trader from a hydroelectric facility near the utility's operational territory or from a second utility generating electricity using coal outside the utility's operational territory. The emissions associated with the generation are not known because they could be significantly different for each source. Therefore, the emissions associated with non-firm contract purchased electricity were calculated using the unspecified emission rate factor provided by Ecology that generally reflects the suite of generation sources that produced the purchased electricity.

[6] Calculated, Attachment A (Known Resources)

Centralia Coal Transition Power

It is important to distinguish between emissions from PSE's owned thermal resources above and the contract PSE signed with TransAlta for coal transition power from the Centralia power station ("Centralia"). In this report, PSE incorporates a breakdown of energy and emissions from Centralia and differentiates Centralia generation and Centralia supply, which is power purchased by the owner of Centralia (i.e., TransAlta), and supplied to PSE. PSE's report will apply different emissions factors for energy supplied versus generated from Centralia to reflect known sources of emissions more accurately.

PSE reports the difference between supplied and generated power each year from Centralia in its Annual Report of Energy Delivery to PSE from TransAlta-Centralia Transition Coal in Docket No. UE-121373 ("Coal Transition Report").

PSE's sources of Centralia generation and supply in this report are consistent with its Coal Transition Report.

For power generated from Centralia coal, PSE applied the emission factor following the methodology and data reported to the Environmental Protection Agency (EPA). For power supplied by the Centralia market option, PSE applied the Ecology unspecified rate, 963 lbs per CO_2e/MWh. PSE determined the Ecology unspecified rate was reasonable because it provides consistency given the uncertainty of sources purchased by TransAlta from other Balancing Authority Areas. PSE plans to use this same methodology to differentiate Centralia generation and supply in this report for the Centralia coal transition contract duration.

Population Data

PSE tracks customers served by class of service but does not track the number of people (population) served. Therefore, population data in this report is estimated based upon methodology agreed to by PSE, UTC Staff, and the other utilities.

The total service area population was estimated by multiplying the total residential customers in PSE's service area by the average household size (AHS) of occupied homes, using data from the most recent five-year estimates from the U.S. Census Bureau's American Community Survey (ACS).

For more detailed information, see Appendix 1: Estimation of PSE Service Territory Population.

Unspecified Market Purchases

This report includes energy that PSE has purchased from the spot market associated with the corresponding generation year where the actual generating unit is unknown (unspecified). As stipulated in this rule, PSE uses an unspecified emissions rate for these spot market purchases where the energy source is unknown (WAC 480-109-300(4))[7]. The net system mix emissions rates for PSE and the other utilities during the reporting period have been calculated and provided by Ecology.

[7] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Section 4. Appendices

<u>Appendix 1: Estimation of PSE Service Territory Population</u>

This appendix documents how PSE estimated the population within its service territory to meet the reporting requirement of WAC 480-109-300(2)(c): Megawatt-hours per capita. The estimated population for each reporting year is the product of PSE residential customer count for the year multiplied by the weighted average household size of the counties that PSE provides electric service. The methodology is consistent with the preferred Per Capita Methodology described in the UTC Staff's final report[8] and the Commission's Final Order[9] on the estimation of population in an electric utility service territory. As prescribed in the Commission's Final Order paragraph 17, "To produce the reports required by WAC 480-109-300(2)(c), the utilities should use the methodology agreed upon by stakeholders and described in the final report and this order." [10]

PSE's customer information system is the ultimate source of the annual residential customer count data, which represents the number of households within PSE service territory. These customer count data are as reported in PSE's FERC financial reporting Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others. Not all residents in a multi-family or mixed-use commercial and residential building are included in PSE's residential customer count at this time. PSE does not have reliable data to make a separate adjustment to account for the persons residing in master-metered residential buildings.

The average household size used in PSE's WAC 480-109-300: Energy and emissions intensity metrics is 2.48. This number is the overall average of persons per household for PSE's service territory weighted by the population size for each county.

The source of the five-year average of county-level data is the United States Census Bureau's American Communities Survey, which can be accessed using the Bureau's web-based application QuickFacts at www.census.gov/quickfacts/table/PST045215/00.

The following table details the data and the calculation of the 2.48 persons average household size that used in the determination of PSE service territory population for megawatt hours per capita (WAC 480-109-300(3)(c)).

[8] UE-131732 Proposed EE Metrics Workgroup Results – Final Report, August 7, 2015, (Report at2-3).

[9] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).

[10] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).

2016-2020 Census Bureau, Updated July 2021			
County	Population	Per House	Total
Skagit	130,696	2.55	333,275
Pierce	925,708	2.64	2,443,869
Island	87,432	2.31	201,968
King	2,252,305	2.43	5,473,101
Kitsap	274,314	2.46	674,812
Kittitas	45,499	2.32	105,558
Thurston	297,977	2.5	744,943
Whatcom	228,831	2.47	565,213
		Weighted Average	2.48

Appendix 2: Emissions Reporting Methodology

1. Owned Thermal Resources

PSE wholly owns three dual-fuel combustion turbine generation facilities (Frederickson, Fredonia, and Whitehorn), five natural gas combined cycle generation facilities (Encogen, Goldendale, Mint Farm, Ferndale and Sumas), and one internal diesel combustion generation facility (Crystal Mountain). Also, PSE partially owns one coal-combustion generation facility (Colstrip) and one natural gas combined cycle generation facility (Freddy 1).

PSE's CO_2e emissions from electric operations are calculated using the EPA GHG Mandatory Reporting Rule Subparts C and D (Tiers 2 & 4) calculation methodologies. Utilizing Subparts C & D, carbon dioxide mass is calculated based on the amount of fuel consumed by each generation facility.

Thermal facilities utilizing the Subpart C method include Frederickson, Fredonia Units 1 & 2 and Whitehorn. Annual CO_2e mass emissions using Subpart C are calculated with these plant measurements: 1) fuel heat content (HHV), 2) the amount of fuel burned (volume)[11] and, 3) a default specific emission factor (EF). An example calculation is provided below.

Example = Volume gas x fuel heat content HHV x EF =

(334,172,000 scf natural gas measured) x (0.0010920 MMBtu/scf measured) x
(53.06 kg CO_2/MMBtu) = 21,343 short ton CO_2

Thermal facilities utilizing the Subpart D method include Encogen, Goldendale, Mint Farm, Ferndale, Sumas, Fredonia Units 3 & 4, Freddy 1 and Colstrip. This method utilizes direct continuous emissions measurement systems (CEMS) as prescribed in Part 75 of the EPA Acid Rain Program. Stack gas and flow measurements are measured continuously, and this data is used in prescribed equations (via the CEMS system) to determine total GHG mass. Part 75 also includes certification and Quality Assurance (QA)/Quality Control (QC) requirements to ensure that data validity is confirmed at the beginning of a monitoring program.

2. Firm Contract Purchases

PSE calculated firm contract purchased emissions using the Ecology methodology outlined in WAC 177-444-040(2).

- Step 1: Obtain plant GHG emissions. GHG emissions for this method are defined as the sum of all Subpart C and Subpart D emissions from the individual power plant as

[11] Measured in standard cubic feet (scf).

published by EPA based on 40 CFR[12] Part 98 reporting consistent with the methods adopted in WAC 173-441-120. Emissions are on a calendar year basis and in units of metric tons CO_2e. Use emissions values specific to the calendar year in the calculation.

- Step 2: Obtain plant net electric generation. Net electric generation is the sum of all annual net generation (MWh) from Form EIA-923 for the power plant for the calendar year for all reported fuel type codes.
- Step 3: Calculate transmission losses using the following method as directed by the regulatory agency. Transmission losses are zero MWh if utility claims are reported on a plant net output basis, like utility claims measured at the Busbar.
- Step 4: Obtain cogeneration correction factor. Account for nonelectric heat use at the power plant by dividing the sum of annual electric fuel consumption (MMBtu) by the sum of annual total fuel consumption MMBtu from Form EIA-923.
- Step 5, Firm Contract Plant Emission Rate Equation (Ecology Method) =

$$\frac{\text{EPA plant GHG emissions} \times \text{cogeneration correction factor}}{\text{plant net electric generation}} \times (\text{utility claims} + \text{transmission losses})$$

3. Non-Firm Contract Purchases

PSE’s emissions from non-firm contract purchased electricity were estimated using the net-by-counterparty methodology for purchases and sales of non-firm contract purchased electricity pursuant to the Staff directive described below:

> *“ 3. Unknown Sources – Purchase and sales reporting methodology: After several rounds of discussion last year and after reviewing analysis performed by the utilities, Staff believes the appropriate methodology for reporting purchases and sales is the net-by-counterparty approach:*
> *(a) for each transaction partner whose generation is from an unknown resource, subtract the total annual sales to this party from the total annual purchases from this party;*
> *(b) if the result is positive, apply the Ecology unspecified intensity factor to calculate emissions associated with the net purchase;*
> *(c) if the result is negative, apply an aggregate, fleet-wide emissions intensity factor for the utility’s known sources to calculate emissions associated with the net sale.*
> *Staff understands that this approach has largely been implemented by PSE in prior reports. Staff contends that the net-by-counterparty approach represents an optimal*

[12] CFR stands for Code of Federal Regulations.

balance among the three competing priorities of accuracy, consistency, and burden on company and commission resources."[13]

4. Non-Firm Purchases in the Energy Imbalance Market (EIM)

   1. For non-PSE units:
      - Apply net-by-counterparty calculus described in 3) above

   2. For PSE units:
      - If end-of-year net (by plant) is greater than zero, then PSE was a net purchaser (from the California Independent System Operator, CAISO); assign Commerce rate. If end-of-year net (by plant) is less than zero, then PSE had excess generation.
      - For excess generation from PSE units, will assign "zero" emission rate because emissions are accounted for under "Generation" (to avoid double counting).

[13] UE-170696. *PSE 2007-2016 EEI report Staff Compliance Letter* (June 26, 2018). Staff compliance letter recommending that the Commission acknowledge Puget Sound Energy's compliance with WAC 480-109-300. ATTACHMENT Staff feedback re: PSE's 2007-2016 EEI Report, page 1 of 2.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-57:
Wash. Utils. Comm'n Rejection of Colstrip Investments in Puget Rates

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY Respondent.	DOCKET UE-240729 FINAL ORDER 05 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission rejects the tariff sheets field by Puget Sound Energy (PSE or the Company) filed on September 30, 2024, and allowed to provisionally go into effect subject to refund. The Commission has considered the full record and requires PSE to file tariff sheets that will result in a decrease in revenue of approximately $6,843,705 or 0.08 percent in accordance with the decisions in this Order summarized below, subject to the true-up required by this Order. The Commission concludes that Colstrip Units 3 and 4 will be "retired" within the meaning of CETA when PSE transfers its ownership in those units to NorthWestern Energy Corporation (NorthWestern) on January 1, 2026. The Commission further determines that the Abandonment and Acquisition Agreement (A&A Agreement) is not subject to Commission approval because Colstrip is not useful or necessary for PSE's service in Washington at the time of transfer. However, the Commission establishes a condition to facilitate review of future property transfers to comply with CETA. The Commission determines that PSE's Colstrip investments are not used and useful after December 31, 2025, and that such investments should be prorated, with the exception of six investments in support of human health and safety. The Commission further requires PSE to establish the in-service dates of two other investments, the U4 Generator Exciter and the Northern Cheyenne AAQ System, to establish the prorated level of recovery, if any. The Commission determines that PSE has demonstrated that the prorated portion of its Colstrip investments are prudent, other than its investment in the TOFA SmartBurn component and four projects that lack a capital justification. The Commission further finds that the annual amortization amount associated with the 2024 Colstrip outage should be adjusted to $1,603,174. The Commission finds that PSE should be required to refund over-collected amounts in the manner described in this Order. The Commission further requires PSE to file an accounting of its 2025 Colstrip investments as part of its Sch. 141COL annual filing,* *consistent with the decisions in this Order, to allow for review of its 2025 Colstrip investments.*

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PROCEDURAL HISTORY

1 On September 30, 2024, Puget Sound Energy (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL. PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800 kWh per month would be a rate increase of $.18 or 0.16 percent.

2 On December 19, 2024, this matter came before the Commission at the Open Meeting. Commission staff (Staff) raised concerns about a number of capital investments reflected in the filing that are potentially unrecoverable by law or imprudent for Washington ratepayers. The Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication (Order 01) in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates would go into effect on January 1, 2025, subject to refund.[1] The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

[1] On December 23, 2024, the Commission issued an errata to Order 01 and a revised Order 01. The revision did not affect the substantive terms or determinations in Order 01.

3 On February 27, 2025, Alliance of Western Energy Consumers (AWEC) filed its Petition to Intervene, arguing that it has a substantial interest in this proceeding based on its participation in the establishment of the Colstrip Adjustment Rider Schedule and the impacts of proposed rate increases on AWEC members who purchase power from PSE.[2]

4 On March 6, 2025, NW Energy Coalition (NWEC) filed its Petition to Intervene arguing that it has a substantial interest in this proceeding based upon its historic and ongoing work with utility companies to promote a clean, reliable, affordable, and equitable energy future.

5 On March 12, 2025, the Commission convened a virtual prehearing conference before Administrative Law Judges (ALJ) Harry Fukano and Jessica Kruszewski. At the hearing the presiding ALJ granted AWEC and NWEC's unopposed petitions to intervene in this matter.

6 On March 26, 2025, the Commission entered Order 03, Prehearing Conference Order and Notice of Hybrid Evidentiary Hearing (Order 03), which set an evidentiary hearing for September 3, 2025, at 9:30 a.m.

7 On April 4, 2025, the Commission issued a Notice of Revised Procedural Schedule at the request of PSE to revise the date of the initial settlement conference to April 16, 2025, and for PSE's initial testimony to be due on April 22, 2025. No party opposed PSE's request to modify the procedural schedule.

8 On August 28, 2025, the Commission held a combined virtual public comment hearing in Dockets UE-240729 and UG-240884. Eight participants voiced opposition to PSE's requests for cost recovery in this docket.[3]

9 In addition to the virtual public comments, the Commission and Public Counsel received a total of forty-six written comments with forty opposed, two in favor, and four undecided. Of these commenters, many PSE customers raised concerns about increases in rates while living on a fixed income.[4]

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[2] *WUTC v. Puget Sound Energy*, Dockets UE-220066 & UG-220067 (*consolidated*), and Docket UG-210918 Order 24/10 (Dec. 22, 2022).

[3] *WUTC v. Puget Sound Energy*, Docket UE-240729, Virtual Public Comment Hearing Recording (Aug. 29, 2025).

[4] *WUTC v. Puget Sound Energy*, Docket UE-240729, Comment Matrix Attachment A (Sept. 17, 2025).

10 On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

11 On September 5, 2025, the Commission issued Notice of Bench Requests (BR) 1-4 requesting additional information from the parties with a deadline for responses to BR 1-3 set for September 10, 2025, at 5:00 p.m., and set a deadline for replies from non-company parties to the company's response to BR 1 for September 17, 2025. The deadline for responses to BR 4 was set for September 17, 2025. The Company submitted supplemental responses to BRs 3 and 4 on October 2, 2025.

12 On October 10, 2025, the Commission issued a Notice requesting supplemental briefing from the parties in relation to the interpretation of RCW 19.405.020 to aid the Commission in its decision-making with a deadline for set for October 24, 2025, at 5:00 p.m.

13 On October 21, 2025, the Commission issued BR 5-6 asking the Company to clarify additional questions it had in relation to the Company's investment into SmartBurn and its NOx control system.

14 **PARTY REPRESENTATIVES.** Donna L. Barnett of Perkins, Coie LLP, represents PSE. Nash Callaghan and Josephine Strauss, Assistant Attorneys General, represent Staff.[5] Tad Robinson O'Neill, Jessica Johanson-Kubin, and Robert Sykes, Assistant Attorneys General, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Sommer Moser and Michelle Madsen of Pepple Moser, P.C., represent AWEC. Yochanan Zakai and Orran Balagopalan of Shute, Mihaly & Weinberger, represent NWEC.

BACKGROUND

15 **Clean Energy Transformation Act (CETA).** In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA),[6] codified in chapter 19.405 of the Revised Code of Washington (RCW). In the face of immediate and significant threats posed by climate change, CETA requires that each Washington electric utility "eliminate coal-fired resources from its allocation of electricity" no later than December 31, 2025,[7] that all retail sales of electricity are "one hundred percent carbon-neutral by January 1,

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[5] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To ensure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[6] Laws of 2019, ch. 288, §§ 1–13 and 26. Codified as chapter 19.405 RCW.

[7] RCW 19.405.030(1). *See also* RCW 19.405.020(1)

2030,"[8] and that by January 1, 2045 "one hundred percent of all sales of electricity to Washington retail customers" are supplied by either non-emitting or renewable electricity generation resources.[9] CETA promotes a transition to a clean energy economy,[10] provides incentives for clean alternative energy sources,[11] and expands the meaning of "public interest" under Title 80 RCW.[12] However, CETA's requirement for each utility to eliminate coal-fired resources from its allocation of electricity "does not include costs associated with decommissioning and remediation of these facilities" provided the Commission deems these costs to be prudently incurred.[13]

16 **Colstrip, Ownership and Operations Agreement (O&O Agreement), and Development of the Abandonment and Acquisition Agreement (A&A Agreement).** This case concerns the recovery of PSE's portion of investments in the Colstrip Steam Electric Station (Colstrip). Colstrip was a four-unit coal-fired electric generation facility operated by Talen MT (Talen) and located in Colstrip, Montana.[14] Colstrip Units 1 and 2 were closed in January 2020.[15] At present, PSE owns 25 percent of the remaining Colstrip Units 3 and 4, with the other 75 percent divided among other entities as follows:[16]

	Colstrip Unit 3	**Colstrip Unit 4**
Avista Corporation	15%	15%
NorthWestern Energy Corporation	--	30%
PacifiCorp	10%	10%
Puget Sound Energy	25%	25%
Portland General Electric Company	20%	20%
Talen MT	30%	--

[8] RCW 19.405.010(2); RCW 19.405.040(1).

[9] RCW 19.405.010(2); RCW 19.405.050(1).

[10] RCW 19.405.010(1).

[11] RCW 19.405.010(4).

[12] RCW 19.405.010(6). In enacting CETA, the Legislature found that the public interest includes: (a) the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacts communities;" (b) "long-term and short-term public health, economic, and environmental benefits;" and (c) "the reduction of costs and risks and energy security and resiliency."

[13] RCW 19.405.030(1)(a)-(b).

[14] Atwood, Exh. NLA-1T at 2:9, 7:3-4, 8:19.

[15] Atwood, Exh. NLA-1T at 7:3-4, 12-13.

[16] Atwood, Exh. NLA-1T at 7:3-9.

17 The owners of Colstrip Units 3 and 4 operate under the terms of the Common Facilities Agreement which describes ownership interests, among other things.[17] Contracts relating to Colstrip Units 1 and 2 expired when the units were closed.[18] Additionally, the owners of Colstrip Units 3 and 4 operate under the O&O Agreement, which was entered into in 1981 and continues to govern the operation of the Colstrip units.[19] Under the O&O Agreement, PSE must fund costs to operate and maintain Colstrip Units 3 and 4 as long as the Company holds any ownership shares. [20] This includes requiring each owner to provide the plant with enough coal to generate the owner's share of the plant's minimum operating capacity.[21] Each year, the owners of the Colstrip units must approve a budget, but because PSE holds 25% ownership, it is not the sole entity approving or denying a budget with a minority vote.[22]

18 To comply with CETA's mandate to have coal-fired generation removed from its allocation of electricity by December 31, 2025, PSE has made several prior attempts to sell or dispose of Colstrip Units 3 and 4. PSE first entered into an agreement with NorthWestern in 2019 to sell Colstrip Units 3 and 4 with a purchase price and an exchange of rights on the Colstrip transmission system, but withdrew the agreement after pushback.[23] In a second attempt, in 2022, PSE and Talen worked out an abandonment agreement but the transfer did not occur as Talen went through a bankruptcy in 2024.[24] Talen did not get approval of the PSE abandonment agreement in the bankruptcy, so the agreement was invalidated.[25] PSE then entered into the A&A Agreement with NorthWestern to transfer its interest in Colstrip Units 3 and 4.[26] PSE entered into this agreement without seeking Commission approval.[27] The transfer will occur at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[28]

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[17] Atwood, Exh. NLA-1T at 7:12-13.

[18] Atwood, Exh. NLA-1T at 7:12-14.

[19] Atwood, Exh. NLA-1T at 7:16-18; Atwood, Exh. NLA-4.

[20] Atwood, Exh. NLA-1T at 8:3-4.

[21] Atwood, Exh. NLA-1T at 8:3-7.

[22] Atwood, Exh. NLA-1T at 9:14-20, 16:12-21.

[23] TR Roberts at 94:20-25, 95:1-8; Atwood, Exh. NLA-1T at 19:8-10.

[24] TR Roberts at 95:9-20; Atwood, Exh. NLA-1T at 19:11-22.

[25] Atwood, Exh. NLA-1T at 19:11-22.

[26] Atwood, Exh. NLA-1T at 19:6-22.

[27] Mullins Exh. BGM-1T at 2:10-16.

[28] PSE's Response to BR 3.

I. Applicable Law

19 The Legislature has entrusted the Commission with broad discretion to regulate and set rates in the public interest[29] that are just, fair, reasonable and sufficient,[30] and to balance the needs of the public to have safe, reliable, and appropriately priced services, while also assuring that the utilities earn enough to remain in business.[31] The Commission has previously interpreted the fair, just, reasonable, and sufficient standard to mean that "rates that are *fair* to customers and to the Company's owners; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[32]

20 However, if after hearing the Commission finds that the rates charged by the utility are:

> . . . unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order.[33]

21 For proposed rates, as in this case, the Commission may enter an order under this same standard as if the proposed rates were already effective.[34]

22 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company,[35] and the burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[36]

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[29] RCW 80.01.040(3).

[30] RCW 80.28.010.

[31] *People's Org. for Wash, Energy Res. v. WUTC*, 104 Wn.2d 798, 808 (1985).

[32] *WUTC v. Avista Corp.*, Dockets UE-160228 & UG-160229, Order 06 at 47 ¶ 79 (Dec. 15, 2016) (emphasis in original).

[33] RCW 80.28.020.

[34] RCW 80.04.130(1).

[35] *Id*.

[36] *WUTC v. Pacific Power and Light Company*, Cause No. U-76-18 (Dec. 29, 1976) (internal citations omitted).

23 As discussed above, in 2019, the Legislature expanded the traditional definition of the public interest standard. As Washington state transitions to a clean energy economy, the Legislature provided that the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[37] In achieving these policies, "there should not be an increase in environmental health impacts to highly impacted communities."[38]

24 Following the passage of RCW 80.28.425, which requires utilities to file multi-year rate plans when filing a general rate case (GRC), the Commission indicated its commitment to considering equity while regulating in the public interest: "So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward."[39] The Commission also explained that regulated companies should be prepared to address equity considerations in future cases: "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[40]

II. Application of RCW 19.405.030 - Interpretation of "*Retirement*"

25 CETA requires the following:

> The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service when:
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> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, termination or expiration of any ownership, or an operation agreement affecting such a fossil fuel generating resource; or
>
> (b) The commission finds that the retirement is in the public interest.

[37] RCW 19.405.010(6).

[38] RCW 19.405.010(6).

[39] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 10 ¶ 58 (Aug. 23, 2022).

[40] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 10 ¶ 58 (Aug. 23, 2022).

26 The Company has argued that a transfer of its ownership rights in Colstrip Units 3 and 4 is a retirement under RCW 19.405.030(3) and is the type of transfer the Legislature had in mind when the statute was drafted.[41] PSE argues that it has done exactly what the statute intended and because the "long-lived plant will be retired by PSE upon transfer of ownership . . . the Commission must allow the cost to invest in that plant to be recovered either directly or indirectly in rates, as the law requires."[42] PSE alleges that this treatment applies to 2024 and 2025 plant additions, which will become unrecovered plant as of December 2025.[43]

27 NWEC argues that the Commission should apply the dictionary definition of "retirement" so that in the context of this case, retirement would mean that Colstrip ceases to produce electricity. To support its contention that the Company interprets "retirement" similarly to NWEC, NWEC points to PSE's Colstrip FACTS Frequently Asked Questions webpage, in which PSE states that "there are no plans to retire Colstrip Units 3 & 4" and that only Units 1 and 2 have been.[44] Further, NWEC contends that RCW 19.405.030(3) does not apply to PSE's investments in Colstrip Units 3 and 4 because the statute intended a "financial assurance" that if a company retires a fossil fuel generating resource, as in the resource is no longer working and causing pollution, shareholders would not be asked to write off undepreciated investment.[45] Specifically, NWEC takes the position that CETA intended to incentivize companies to retire fossil fuel plants and that it does not apply to investments that extend the life of the plant beyond 2025.[46] NWEC supports this assertion by noting that "those financial incentives were carefully written in the past tense, so that they only apply after the plant 'has been retired from service.'"[47] Because Colstrip Units 3 and 4 will continue to operate beyond 2025, NWEC argues that they will not be retired as intended by CETA, so RCW 19.405.030(3) does not apply to this proceeding.[48]

28 In applying the language of RCW 19.405.030(3)(a), NWEC contends that "termination or expiration of any ownership" does not independently constitute retirement and that the

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[41] Steuerwalt, Exh. MS-1T at 8:13-16.

[42] Steuerwalt, Exh. MS-1T at 8:13-19.

[43] Steuerwalt, Exh. MS-1T at 8:19-20, 9:1-2.

[44] McCloy, Exh. LCM-1T at 6:6-8.

[45] McCloy, Exh. LCM-1T at 6:11-14.

[46] McCloy, Exh. LCM-1T at 6:14-21.

[47] McCloy, Exh. LCM-1T at 6:20-21, 7:1.

[48] McCloy, Exh. LCM-1T at 7:1-6.

statute lists causes of retirement and does not "define or alter the plain meaning of the word retired."[49] Similarly, NWEC alleges that section (3)(b) of the statute that allows "such treatment if the retirement of the facility is in the public interest[]" does not apply because Colstrip Units 3 and 4 have not been retired, but even if they had, life extending investments are not prudent nor in the public interest [50]

29 Additionally, NWEC argues that CETA requires electric utilities to "eliminate coal-fired resources from their 'allocation of electricity' by December 31, 2025," but "makes an explicit exception for decommissioning and remediation costs."[51] NWEC interprets this to mean that "CETA did not authorize the recovery of undepreciated investment in fossil resources that remain in-service beyond December 31, 2025."[52]

30 Public Counsel takes a similar position to NWEC and argues that Colstrip Units 3 and 4 will not be retired as intended by RCW 19.405.030(3) after December 31, 2025.[53] Further, Public Counsel alleges that RCW 19.405.030(3) does not apply to this proceeding and the Commission should construe the word "retire" according to its plain language meaning, in which case there are no identifiable retirement dates for Colstrip Units 3 and 4.[54]

31 In response to NWEC's assertion that retirement means "cease to work", PSE asserts that NWEC has misapplied the definition of "retire" and that the "accounting definition of retire related to physical assets that is more relevant here."[55] Specifically, PSE contends that an accounting definition is more appropriate and what was contemplated in the legislation because the statute references "depreciation schedules" which utilize the accounting definition of "retirement."[56] PSE offers two accounting definitions of retirement:

(1) . . . that asset is no longer under the control of that entity . . . [57] , and

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[49] McCloy, Exh. LCM-1T at 7:11-21.

[50] McCloy, Exh. LCM-1T at 8:3-6.

[51] Cebulko, Exh. BTC-1CT at 10:17-20, 11:1-2.

[52] Cebulko, Exh. BTC-1CT at 11:2-6.

[53] Dreyer, Exh. JMD-1CTr at 4:12-18.

[54] Dreyer, Exh. JMD-1CTr at 4:12-16.

[55] Free, Exh. SEF-1T at 2:15-19, 3:1-3.

[56] Free, Exh. SEF-1T at 3:13-17; RCW 19.405.030(2).

[57] Free, Exh. SEF-1T at 4:3-17 (*citing* the master glossary of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification, and Generally Accepted Accounting Principles (GAAP), that defines "retirement" as: "The other-than-temporary removal of a long-lived asset from service. That term encompasses sale, abandonment, recycling, or disposal in some

(2) Retirement of a tangible asset (retirement encompasses its sale, abandonment, recycling or disposal in some other manner) . . .[58]

PSE argues that NWEC's definition of "retire" as "cease to work" is not found within the CETA statute and that NWEC's interpretation "ignores its plain language, and it utilizes a general dictionary definition rather than the specific accounting and regulatory framework that governs utility asset treatment."[59] Further PSE explains that the Financial Accounting Standards Board (FASB) as the authoritative Generally Accepted Accounting Principles (GAAP) source, controls over dictionary definitions in a regulatory context.[60] PSE further asserts that under RCW 19.405.030(3)(a) the term retirement includes "termination or expiration of any ownership"[61] and that the Commission should not be swayed by the restrictions NWEC places on the term retirement as it is used in the statute. [62]

32 The Company argues that CETA intended for coal to be retired from a utility's portfolio with the "financial assurance that shareholders would not be asked to write-off any undepreciated plant investment."[63] The Company asserts that the Legislature expressly included the termination or expiration of ownership to be a cause of retirement and did not include physical cessation of generation as a condition.[64]The Company contends that the central mandate of CETA is to eliminate coal-fired resources from a utility's "'allocation of electricity' by December 31, 2025."[65] To support this contention, the Company asserts that by referencing CETA's use of "depreciation schedules" and "books of account" the Legislature intended for an accounting definition of "retire."[66] The Company also referred to the definition of retirement under Generally Accepted Accounting Principles and by the

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other manner. However, it does not encompass the temporary idling of a long-lived asset. After an entity retires an asset, that asset is no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed." https://asc.fasb.org/MasterGlossary).

[58] Free, Exh. SEF-1T at 4:9-17 (*citing* the definition for "retirement" as used by the State of Washington, Office of the Washington State Auditor).

[59] Free, Exh. SEF-1T at 5:1-9.

[60] Free, Exh. SEF-1T at 5:7-9.

[61] Steuerwalt, Exh. MS-1T at 9:18-20; RCW 19.405.030(3)(a)

[62] Steuerwalt, Exh. MS-1T at 9:23-24, 10:1-5.

[63] Brief of PSE at 8 ¶ 17.

[64] Brief of PSE at 8-9 ¶ 18.

[65] Brief of PSE at 9 ¶ 18.

[66] Brief of PSE at 9 ¶ 19.

Washington State Auditor to support CETA's intent for the accounting definition to be used to interpret the term "retire."[67]

33 Public Counsel argues, first, that the Commission should look to the plain language to interpret the word "retirement" in the CETA statute, which is not the accounting definition. Next, Public Counsel emphasizes that the Commission should look to the complete statute and that CETA is concerned with eliminating coal-fired power from Washington's electricity supply and that the primary concern is not depreciation schedules. Using these methods of statutory interpretation, Public Counsel construes "retirement" as used in CETA to mean "end of working life of coal-fired power."[68] The language of RCW 19.405.030(3) allows for recovery of an investment ". . . in a fossil fuel generating resource that has been retired from service . . ." which Public Counsel argues, gives utilities the opportunity to recover on their investments at the time CETA was enacted rather than allowing "companies to accrue millions of dollars of additional life extending costs after CETA was enacted only then to administratively 'retire' the assets on December 31, 2025[.]"[69] Public Counsel stresses that the plain language and spirit of CETA is to provide cost recovery to Washington utilities that close plants, not for transferring assets.[70]

34 In response to the Company's arguments, NWEC asserts "that allowing recovery of undepreciated investment only in fossil resources that *actually cease operations* was 'intended to remove a disincentive for PSE and other Washington owners to retire fossil plants.'"[71] Similar to Public Counsel, NWEC explains that the financial incentives to retire fossil plants were "'carefully written in the past tense' to reflect the Legislature's intention" that recovery of undepreciated investment only occur if the plant "ceased operations."[72]

Commission Determination

35 To understand what the Legislature meant by the word "retire" in CETA, we look to the canons of statutory interpretation. Although NWEC argues that the starting point to interpret a statutory term is to look to its "plain language and ordinary meaning", a technical term should be given its technical meaning rather than its general purpose

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[67] Brief of PSE at 9 ¶ 19; Free, Exh. SEF-1T at 4:3-17.

[68] Brief of Public Counsel at 16 ¶ 50.

[69] Brief of Public Counsel at 16-17 ¶ 52; RCW 19.405.030(3).

[70] Brief of Public Counsel at 16-17 ¶ 52.

[71] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:14-16).

[72] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:20-21, 7:1).

dictionary definition.[73] NWEC has provided a narrow scope for defining the term "retire" for the purposes of statutory interpretation and has not considered a technical meaning. In this case, we must also consider "the context of the statute in which that provision is found, related provisions, and the statutory scheme as a whole."[74] Further, we also consider "'all the terms and provisions of the act in relation to the subject of the legislation, the nature of the act, the general object to be accomplished and consequences that would result from construing the particular statute in one way or another.'"[75]

36 Although NWEC has maintained its position that the Commission should apply the dictionary and plain language meaning to the word "retire", NWEC looks to RCW 19.405.010(2) to provide context to the statute. However, RCW 19.405.010(2) refers to transforming Washington's electrical system, which will be accomplished even if Colstrip Units 3 and 4 cease to operate. The Company argues that the statute refers to depreciation schedules to provide context to the intent of the Legislature, and that this is an accounting term. Further, the Company contends that CETA allows for recovery of undepreciated investment when the retirement is caused by the termination or expiration of ownership which demonstrates the Legislature's intent that retirement not be narrowly construed to only mean that the plant is no longer in operation.

37 The Company provided two sources for the accounting definitions for the word "retirement" to guide the Commission in interpreting CETA and identifying whether the Company is able to recover undepreciated investments in Colstrip Units 3 and 4 under RCW 19.405.030(3). Because the statute references depreciation schedules and books of account, the Company has provided the definition used by GAAP, which we find to be a credible source in determining the technical definition of "retire" because it provides the definition as used in regulatory accounting. Further, the Company provides the definition of "retirement" used by the Washington State Auditor's Office, which also considers retirement to be when an asset is no longer controlled by the entity, or controlled by another entity. The Company argues that Colstrip Units 3 and 4 will be retired for PSE under both of these definitions as of January 1, 2026, thus the provisions of RCW 19.405.030(3) apply, and permit the Company to recover its undepreciated investments in Colstrip Units 3 and 4.

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[73] *Tingey v. Haisch,* 159 Wn.2d 652, 658 (2007).

[74] *Taylor v. Burlington N. R.R. Holdings, Inc.*, 193 Wn.2d 611, 614 (2019).

[75] *Burns v. City of Seattle,* 161 Wn.2d 129, 146 (2007) (*citing State v. Krall,* 125 Wn.2d 146, 148 (1994) and *State v. Huntzinger*, 92 Wn.2d 128, 133 (1979)).

38 Because CETA is a relatively new statute without much context and related provisions to help us understand what the Legislature intended with the word “retire”, we also consider the object to be accomplished by CETA, which is, among other things, to remove coal-fired resources from Washington’s electricity supply by the end of 2025, and perhaps more importantly, the impacts of construing the statute one way or another. Public Counsel has argued that CETA intends to provide incentives to utility companies to close coal-fired plants, which Public Counsel argues is demonstrated by the use of past tense, which means the Company cannot recover any undepreciated investments until after the coal-fired plants are no longer operational. Public Counsel further argues that CETA could not have intended for companies to accrue millions of dollars of additional life extending costs after CETA was enacted only to then transfer the plants rather than fully decommission them. However, we have concerns when we look to the reality of the position the Company is placed in if CETA required it to fully decommission Colstrip Units 3 and 4.

39 The Company is required to maintain the plants and fulfill its contractual obligations to other entities. The Company would be faced with the impossible scenario where CETA requires it to not invest in the plants and to not meet its contractual obligations, which could result in a situation where the Company is required to turn to the market to provide power at a much higher cost to customers. The alternative for the Company is to invest in the plant to ensure its safe and reliable operation until it no longer owns its portion of the plant and meet its contractual obligations, but then to absorb the costs to maintain the plants. We are not persuaded that the Legislature intended for electric utility companies to be responsible for the costs to maintain coal-fired plants to provide electricity to Washington customers and then fully decommission coal-fired plants by the end of December 31, 2025.

40 First, we must determine whether the Company can recover undepreciated investments under RCW 19.405.030(3). NWEC and Public Counsel have both argued that because Colstrip Units 3 and 4 will still be operational as of January 1, 2026, the plant will not be retired by the end of December 31, 2025, and the Company cannot recover its undepreciated investment in the plant. The Company has argued that the Legislature intended the accounting definition of “retire” to apply because the statute references depreciation schedules, books of accounts, and sets a condition of retirement to include termination or expiration of ownership. We find this argument persuasive when we look at the context of the statute. We also agree that the Legislature expressly identified termination or expiration of ownership, but did not include language specifically requiring coal-fired plants to no longer be operational, and find this persuasive in demonstrating that the Legislature intended for an accounting definition of the word “retirement.” We do not

agree with NWEC and Public Counsel that the Legislature intended a dictionary definition for the word "retirement" because the statute calls for a technical definition.

41 Next, we consider that the purpose of CETA is to remove coal-fired electricity from Washington's electricity supply by the end of December 31, 2025. That is still accomplished if Colstrip Units 3 and 4 are transferred to NorthWestern and are no longer providing electricity in Washington, even if the plants are not entirely shut down. We have great concern about interpreting RCW 19.405.030(3) to mean the Colstrip Units must cease to operate in order for the Company to recover the investments it made into the plant for which it had a contractual obligation to maintain. If we decide otherwise the Company shareholders would be left having to absorb all of the investments made, which we do not believe was the Legislature's intent. Colstrip Units 3 and 4 are jointly owned so PSE cannot unilaterally choose to "retire" or decommission the plant. Specifically, if the Company had not invested in the maintenance of the plant, the Company would have been in breach of its O&O Agreement with its co-owners and would have had to turn to the market for power, which, based on the evidence presented in this case, likely would have been more costly for PSE's customers than maintenance of the plant.[76] For these reasons, we find it reasonable that the accounting definition should apply in the interpretation of RCW 19.405.030(3). As the Company is under contract to transfer its interest in Colstrip Units 3 and 4 on January 1, 2026, we find that PSE will have retired coal-fired electricity from its electrical supply in Washington and that RCW 19.405.030(3) does not preclude the Company from recovering at least some of the undepreciated investments in Colstrip Units 3 and 4.

III. Asset Transfer

42 PSE entered into the A&A Agreement with NorthWestern on July 30, 2024, to comply with the CETA requirement to no longer include coal-fired power in its allocation of electricity after December 31, 2025. The A&A Agreement transfers PSE's ownership interest in Colstrip Units 3 and 4 by way of abandonment to NorthWestern without a purchase price at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[77] Public Counsel, NWEC, and AWEC raised concerns about the transfer, primarily that the transfer has no purchase price and has not been reviewed or approved by the Commission.[78] Specifically,

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[76] Atwood, Exh. NLA-1T at 16:12-21, 17:5-18; Atwood, Exh. NLA-4.

[77] Mullins, Exh. BGM-3 at 19-20; PSE's Response to BR 3.

[78] See Dreyer, Exh. JMD-1CTr at 7:8-22; Cebulko, Exh. BTC-1CT at 5:17-20; Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

Public Counsel asserts that the investments PSE seeks to recover in this docket may have been covered with a purchase price.[79] NWEC maintains that the Commission should rule on the prudence of the transfer.[80] AWEC argues that NorthWestern should be obligated to pay a fair value because the capital additions will benefit its customers and not PSE customers.[81] AWEC further contends that PSE could have elected to operate its share of Colstrip as a merchant plant.[82]

43 PSE maintains that its decision to enter into the A&A Agreement transferring its ownership share of Colstrip to NorthWestern was reasonable considering the circumstances confronting the Company at the time that it entered into the agreement. PSE states that at the time it signed the A&A Agreement in July 2024, PSE anticipated substantial costs related to bringing Colstrip into compliance with Mercury and Air Toxics Standards (MATS).[83] PSE asserts that the potential MATS compliance costs ultimately caused its planned transfer of Colstrip to the plant operator, Talen to fail.[84] PSE further argues that the Commission should afford little weight to Public Counsel's questioning of PSE witness Roberts regarding an exemption to MATS compliance, based on the lack of documentary evidence in the record regarding the exemption, contending that prudence is concerned with what the utility knew at the time it made a decision.[85]

44 The Company contends that its decision to transfer its Colstrip ownership interest to NorthWestern for no purchase price was reasonable because the potential MATS compliance obligations rendered Colstrip a value-negative asset.[86] PSE also argues that the CETA deadline to remove coal power from the Company's allocation of electricity undermined PSE's bargaining leverage because potential buyers knew that PSE was unable

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[79] Dreyer, Exh. JMD-1CTr at 8:1-4.

[80] Cebulko, Exh. BTC-1CT at 5:17-20.

[81] Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

[82] Mullins, Exh. BGM-1T at 9:3-21.

[83] Brief of PSE at 24 ¶ 43; Roberts, Exh. RJR-1T at 3:18 – 4:8 (noting July 2024 MATS compliance estimates of $459,000,000 to $594,000,000).

[84] Brief of PSE at 24 ¶ 43; Roberts, TR. at 95:9-20.

[85] Brief of PSE at 24 ¶ 43.

[86] Brief of PSE at 25-26 ¶¶ 44-45; Roberts, Exh. RJR-1T at 4:9-18 (stating "no rational purchaser would ascribe positive value to [Colstrip]" and "[Colstrip]'s fair market value was already demonstrably negative, and any attempt to monetize it would have imposed a greater burden on PSE's Washington ratepayers than an outright abandonment.").

to retain long-term ownership in Colstrip.[87] PSE states that its bargaining power regarding Colstrip was further limited by the Company's need to maintain its Colstrip transmission rights, reducing the number of potential acquirers.[88] Based on these factors, PSE maintains that NorthWestern was the only purchaser who was willing and operationally capable of acquiring PSE's Colstrip ownership interest and that PSE's lack of bargaining power, combined with the need to quickly transfer Colstrip ownership, made a no-value transfer prudent under the circumstances.[89] The Company asserts that no other party has demonstrated that another entity was willing to purchase PSE's Colstrip ownership or identified an appropriate selling price that PSE should have acquired.[90] Furthermore, the Company states that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because as of December 31, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public.[91]

45 PSE argues that AWEC's proposal that PSE could have retained its ownership interest in Colstrip and operated as a merchant plant would be unreasonably risky for the Company and contrary to Washington clean energy policy. PSE states that while it could have conceivably operated its share of Colstrip as a merchant plant, it would not be able to control dispatch or capital project decisions, which creates a risk that PSE would be forced into uneconomical decisions due to its minority ownership share.[92] PSE contends retaining ownership in Colstrip would have required PSE to participate in a new long term coal fuel contract for the plant, which creates risk that the Company would not be able to recover associated fuel costs.[93] The Company further suggests that its net present value (NPV) analysis demonstrates that the primary risk to Colstrip is an outage event that necessitates the acquisition of power at higher costs, and that merchant plant operation increases this risk.[94] PSE also maintains that it could face potential litigation over an attempt to operate

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[87] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 4:20 – 5:15.

[88] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:14 – 7:8. *See also* Roberts, TR. at 94:20 – 95:8 (explaining that the first attempted sale of PSE's Colstrip ownership was withdrawn in part because other parties to the proceeding objected to PSE's proposal to sell part of its Colstrip transmission system rights).

[89] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:3 – 8:6.

[90] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 8:9-18. *See also* Roberts, TR. at 94:20 – 96:22 (explaining that PSE had previously failed to sell or transfer its ownership interest in Colstrip two times prior to entering into the A&A Agreement with NorthWestern).

[91] Roberts, Exh. RJR-1T at 11:3-14.

[92] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 9:3-14.

[93] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 10:4-8.

[94] Brief of PSE at 27 ¶ 48; Atwood, NLA-11T at 14:7-12.

Colstrip as a merchant plant because its incorporation agreements prohibit the Company from creating subsidiaries.[95] PSE states that, even if it were able to operate Colstrip as a non-regulated subsidiary, such operation would either only benefit shareholders or lead to potential cost allocation disputes.[96] Finally, PSE asserts that operating Colstrip as a merchant plant would conflict with the intent of CETA and Washington's clean energy policy.[97]

46 NWEC argues that the A&A Agreement between PSE and NorthWestern requires Commission approval pursuant to RCW 80.12.020. NWEC asserts that PSE's argument that Colstrip will no longer be necessary or useful in its duties to the public as of December 31, 2025, is circular, because PSE is abandoning Colstrip to NorthWestern as of the date of that agreement and suggests that if PSE's interpretation is correct, then every abandonment agreement would evade Commission review.[98] NWEC contends that, even if PSE's interpretation is correct, the Commission is still required to approve the agreement because PSE agreed to align its voting with NorthWestern as part of the A&A Agreement.[99] While NWEC states that it is not asking the Commission to void the A&A Agreement, it maintains that the Commission should not allow PSE to both avoid review of the A&A Agreement and fully recover costs that allow Colstrip to continue operating beyond December 31, 2025.[100]

47 AWEC argues that the Commission has authority to review the A&A Agreement pursuant to RCW 80.12.020. AWEC asserts that Colstrip cannot both be a regulatory asset subject to ratemaking treatment and not subject to the Commission's approval under RCW 80.12.020 with respect to its transfer to NorthWestern.[101] AWEC maintains that, if PSE's transfer of Colstrip is not subject to Commission approval, then Colstrip is a merchant power plant that is not eligible for recovery of undepreciated investment under RCW 19.405.030.[102] AWEC contends that it is unreasonable for PSE to request full recovery of its investments in Colstrip while also transferring its ownership of Colstrip to NorthWestern without

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[95] Brief of PSE at 27-28 ¶ 49; Roberts, TR. at 106:15-18.

[96] Brief of PSE at 27-28 ¶ 49; Roberts, Exh. RJR-1T at 9:15 – 10:3.

[97] Brief of PSE at 27 ¶ 47; Roberts, Exh. RJR-1T at 10:9-12.

[98] Brief of NWEC at 11-12 ¶ 27.

[99] Brief of NWEC at 12 ¶ 28.

[100] Brief of NWEC at 12 ¶¶ 29-30.

[101] Brief of AWEC at 3 ¶ 7.

[102] Brief of AWEC at 3 ¶ 7.

Commission oversight.[103] AWEC further cautions against relying on the timing of the Colstrip ownership transfer as a basis to not approve the transaction, as the timing may imply that Colstrip is operating as a merchant plant.[104]

48 AWEC maintains that the Commission should find PSE's reasons for entering into the A&A Agreement unpersuasive and states that if PSE is correct that Colstrip is of no value, then the plant should be immediately retired.[105] AWEC states that PSE's transfer of its Colstrip ownership to NorthWestern at no cost is not supported by economic analysis and is undermined by the decommissioning and remediation obligations that PSE retains under the A&A Agreement.[106] AWEC argues that the A&A Agreement is not in the public interest because it provides no value to Washington customers and requires PSE to surrender its discretion to NorthWestern for the benefit of NorthWestern's ratepayers.[107] AWEC further asserts that PSE could have elected to operate Colstrip as a merchant plant, that the Commission should not find the Company's arguments about the risks of operating Colstrip as a merchant plant persuasive, and that PSE chose to not operate Colstrip as a merchant plant to protect its shareholders.[108]

49 Both AWEC and Public Counsel recommend that the Commission require PSE to submit a separate filing to approve the A&A Agreement.[109]

Commission Determination

50 RCW 80.12.020(1) provides:

> No public service company shall sell, lease, assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever,

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[103] Brief of AWEC at 3 ¶ 7.

[104] Brief of AWEC at 4 ¶ 8. The Commission declines to consider the testimony filed in another docket cited by AWEC. This evidence is not part of this record in this proceeding and the Commission has already rejected a prior attempt to refer to related testimony that has not been made part of the record. *See WUTC v. Avista Corp.*, Docket UE-240891, Order 06 (Sept. 30, 2025) (striking reference to testimony in Docket UE-240729 because the testimony had not been made part of the record).

[105] Brief of AWEC at 5-6 ¶¶ 10-11; Mullins, Exh. BGM-1T at 3:2-4.

[106] Brief of AWEC at 5-6 ¶ 11.

[107] Brief of AWEC at 5-6 ¶ 11; Mullins, Exh. BGM-1T at 7:10-17.

[108] Brief of AWEC at 6 ¶ 12.

[109] Dreyer, Exh. JMD-2CT at 3:11 – 4:12; Mullins, Exh. BGM-1T at 12:21 – 13:3.

> which are necessary or useful in the performance of its duties to the public, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities with any other public service company, without having secured from the commission an order authorizing it to do so. The commission shall not approve any transaction under this section that would result in a person, directly or indirectly, acquiring a controlling interest in a gas or electrical company without a finding that the transaction would provide a net benefit to the customers of the company.

51 For RCW 80.12.020(1) to apply, the property that a public service company seeks to "sell, lease, assign or otherwise dispose of," must be "necessary or useful in the performance of [the public service company's] duties to the public." Pursuant to RCW 19.405.030(1)(a), each electric utility must eliminate coal-fired resources from its allocation of electricity on or before December 31, 2025, such that the costs and benefits associated with coal resources are removed from the electric utility's retail customer rates.[110]

52 During this proceeding, PSE updated its A&A Agreement to make the transfer of its Colstrip ownership to NorthWestern effective as of 12:00 a.m. Pacific Time, January 1, 2026.[111] As such, PSE's transfer of its Colstrip ownership to NorthWestern will occur after CETA's requirement to remove coal from the Company's allocation of electricity takes effect. Importantly, PSE has preserved its Colstrip transmission rights through the A&A Agreement.[112]

53 In general, every transfer of property that is useful and necessary from a public service company to another entity is subject to Commission approval pursuant to RCW 80.12.020. However, by prohibiting the use of certain resources for service in Washington, CETA has a unique interaction with the transfer of property statute, insofar as CETA effectively makes certain generating resources neither necessary or useful for service after a specific point in time. For coal-fired resources, that point in time is December 31, 2025.[113] Consequently, the Commission determines that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because, at the time PSE's Colstrip ownership is transferred to NorthWestern, Colstrip will not be "necessary or useful in the

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[110] *See* RCW 19.405.020(1).

[111] PSE's Supplemental Response to BR 3 (October 2, 2025).

[112] Roberts, Exh. RJR-1T at 6:14-15; Roberts, TR. at 98:15 – 99:1.

[113] RCW 19.405.030(1)(a).

performance of [PSE's] duties to the public," other than the Colstrip transmission rights, which the Company has retained.[114]

54 The Commission is cognizant of the fact that this conclusion is unique and unusual. However, as will be addressed elsewhere in this Order, the fact that the Commission is not reviewing the A&A Agreement for approval does not mean that the Commission will refrain from examining actions taken pursuant to the A&A Agreement under other Commission standards. The Commission's determination that the A&A Agreement is not subject to review because Colstrip's generation will not be necessary or useful in the performance of PSE's duties to the Washington public is consistent with RCW 19.405.030(3)'s requirement that coal-fired resources be removed from PSE's allocation of electricity. Moreover, the Commission is not without recourse to fashion alternative review mechanisms pursuant to its statutory duty to regulate in the public interest.[115]

55 In order to facilitate future review of the transfer of property that will become unable to serve Washington customers in the future due to the requirements of CETA, including but not limited to RCW 19.405.030-.050, the Commission shall require PSE to comply with the following condition:

> Going forward from the date of this Order, where PSE executes an agreement transferring assets for the purpose of complying with a requirement in CETA, PSE must file that agreement with the Commission for review and, if deemed necessary by the Commission, approval within five days of entering into the agreement, even where the resource may no longer be necessary or useful in the performance of its duties to the public by operation of CETA. In its review of the agreement, the Commission will consider whether the agreement is consistent with the public interest and equity concerns of CETA.

56 As the Commission has determined that the A&A Agreement is not subject to approval under RCW 80.12.020, it is unnecessary to resolve the arguments regarding whether PSE could have operated its portion of Colstrip as a merchant plant. However, the Commission observes that PSE presented credible evidence that the Company faced financial and legal risks if it elected to operate Colstrip as a merchant plant, PSE had a difficult bargaining position with respect to Colstrip, and PSE had made previous efforts to transfer its Colstrip

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[114] *See also* Mullins, Exh. BGM-1T at 10:7-12 ("If the transaction occurs prior to 12:00 Midnight on January 1, 2026, the deadline to remove coal from rates, then the transaction must, without question, be considered to involve utility plant subject to the property disposition requirements. If it occurs after 12:00 Midnight on January 1, 2026, then the transaction could potentially, but not necessarily, be viewed as a transaction of a merchant plant not subject to the approval process.").

[115] RCW 80.01.040.

ownership prior to the A&A Agreement.[116] Furthermore, insofar as CETA prohibits the cost and benefits from coal-fired resources to be included in retail electric customer rates, it is unclear how the operation of Colstrip as a merchant plant would have any direct or indirect value to PSE's Washington customers. There is no analysis in the record before the Commission regarding what those benefits could be, and the Commission will not presume that such benefits exist in the absence of supporting evidence. Finally, issues regarding decommissioning and remediation costs are not properly before the Commission in this case and will be reviewed in a later proceeding when such costs are proposed for inclusion in rates.

IV. Investments in Colstrip

57 As an initial matter, the discussion of PSE's Colstrip investments is somewhat complicated by the fact that different parties propose different categorizations of investments based on their respective positions. While there is some overlap between the parties' organization of investments and issues, the parties' organizations do not necessarily follow a uniform pattern. Therefore, the Commission will proceed by giving a brief overview of the parties' various positions and identify what assets each party has grouped under their respective categories in the interest of clarity.

PSE – Initial Position

58 PSE states that the purpose of this filing is to seek a determination of prudence and cost recovery for capital investments placed into service in 2024 through Schedule 141COL that are currently subject to refund.[117] PSE explains that it attempted to avoid including any capital investments that were expected to close in 2025 to minimize forecasting, although its filing does contain four projects that had closings in 2024 that are anticipated to be in service in 2025.[118] The Company further indicates that a final reporting of capital

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[116] Roberts, Exh. RJR-1T at 3:19 – 8:6, 9:3 – 10:8; Roberts, TR. at 94:20 – 96:22. However, the Commission expresses concern that PSE omitted the fact that Colstrip had received an exemption to the MATS compliance obligations from its testimony. Roberts. TR. at 90:1-3. ("Q: Okay. And Colstrip received an exemption from the EPA's MATS, correct? A: After the abandonment agreement was reached, yes."). The Commission expects a greater degree of candor from the utilities that it regulates, and the lack of documentation regarding the MATS exemption for Colstrip is unavailing when PSE's own witness verified that an exemption had been granted. A lack of forthrightness may subsequently impact a party's credibility before the Commission.

[117] Atwood, Exh. NLA-1T at 2:7-11, 5:22-23.

[118] Atwood, Exh. NLA-1T at 5:23-25 fn. 11. *See also* Atwood, Exh. NLA-5C; Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects with 2025 in service dates as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Chyenne AAQ System).

investments that are placed into service beyond the investments included in this filing will be made in its annual reports filed on or before September 30, 2025, and in 2026 after PSE has applied unrecovered plant against Production Tax Credits (PTC).[119]

59 PSE further argues that it has demonstrated that the costs the Company seeks to include in rates are prudent. The Company argues that it has demonstrated the need for its Colstrip investments based on its contractual obligations, the Colstrip operator's evaluation of the plan and cost benefit analysis, and the relatively high cost of replacement power.[120] The Company asserts that its decision to vote "no" on certain 2024 Colstrip budget items reflects PSE's attempt to consider alternatives to further capital additions, but that it cannot control the budgeting process based on its minority ownership share in Colstrip.[121] PSE further testifies that it coordinated with and kept its management reasonably informed about the investments at Colstrip.[122] Finally, PSE states that it has provided relevant contemporaneous documentation regarding the Colstrip costs in this proceeding.[123]

Staff

60 Staff does not challenge PSE's recovery of three categories of costs associated with Colstrip, totaling 25 projects. First, Staff does not contest ten projects with de minimis costs, defined by Staff as projects included in the Colstrip tracker that were less than $50,000, because these projects are not likely to have a material impact on rates.[124] Second, Staff does not challenge six projects associated with human health and safety concerns because "Staff accepts that the near-term benefits of those projects exceed the costs of the investments."[125] Third, Staff declines to challenge seven routine maintenance projects with

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[119] Atwood, Exh. NLA-1T at 6:1-5.

[120] Atwood, Exh. NLA-1T at 7:10 – 8:11, 10:17 – 11:9, 14:15 – 15:6; Exh. NLA-7C.

[121] Atwood, Exh. NLA-1T at 16:10 – 18:19.

[122] Atwood, Exh. NLA-1T at 20:8-17.

[123] Atwood, Exh. NLA-1T at 21:1-8; Exh. NLA-7C; Exh. NLA-10C.

[124] McGuire, Exh. CRM-1T at 8:1 – 9:5. Staff further explains that while at least one other project, the Northern Cheyenne AAQ system, met Staff's criteria for de minimis projects, Staff is contesting that project because the Company has not demonstrated that it is used and useful for service. McGuire, Exh. CRM-1T at 8:7-12. Staff states that the 10 de minimis projects consist of: (1) Opacity Monitor Replacement; (2) PLC to DCS Obsolescence; (3) Paste Plant Overflow Structure Mod; (4) Mercury Monitor Replacement U3; (5) Mercury Monitor Replacement U4; (6) River Pump Motor; (7) Boiler Feed Pump Rebuild; (8) PA Fan Motor Rewind; (9) Boiler Feed Booster Pump; and (10) Motor Circ Water Pump Cap. McGuire, Exh. CRM-1T at 8:14-20.

[125] McGuire, Exh. CRM-1T at 9:9 – 11:5. Staff identifies the six human health and safety projects as: (1) Switchgear modification; (2) U4 Boiler Snubber Rebuild; (3) Coal Pipe Replacement; (4) U4

an expected service life of four years or less,[126] reasoning that the Commission has previously distinguished between life-extending investments and routine capital maintenance and arguing that routine capital maintenance may be more appropriate for inclusion in rates.[127] Staff confirms that all of the projects that it is not contesting were placed into service during 2024.[128]

61 Staff challenges 13 of the 38 projects that PSE seeks to recover in this proceeding across three categories of assets.[129] First, Staff argues that the Commission should disallow one project related to the SmartBurn NOx Control System.[130] Second, Staff contends the Commission should disallow two projects that will not be used and useful in Washington in 2025.[131] Third, Staff asserts that the Commission should prorate ten projects that represent investments in long-lived plant.[132]

Projects Not Used and Useful

62 Staff maintains that the Commission should disallow recovery of the Unit 4 Generator Exciter and Northern Cheyenne AAQ System because the Company has not demonstrated that those investments are used and useful for service in Washington. Staff asserts that PSE has only identified estimated in-service dates for these two capital projects, which is insufficient to establish that the capital assets will be used and useful in Washington.[133]

Hot Reheat Elbow Replacement; (5) U4 Boiler Scaffolding; and (6) U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[126] McGuire, Exh. CRM-1T at 12:3-7 (identifying the routine maintenance projects as: (1) U4 Auxiliary Turbine Overhaul; (2) U4 Turbine/Generator Base Overhaul; (3) U4 Boiler Coutant Bottom; (4) U4 Air Preheater Basket Replacement; (5) U4 Boiler Waterwall Replacement; (6) U4 Boiler Economizer Tube Replacement; and (7) U4 Air Preheater Seal Replacement).

[127] McGuire, Exh. CRM-1T at 11:9 – 13:3. Staff further clarifies that while 18 of PSE's projects met its criteria for routine maintenance, 11 of the projects either have de minimis costs (four projects), were human health and safety projects (four), or were related to SmartBurn (three). McGuire, Exh. CRM-1T at 11:16 – 12:2. Staff subsequently revised its position and determined that two of the three investments that were originally categorized as SmartBurn should be recovered in full through rates as expenses related to routine maintenance. Brief of Staff at 5 ¶ 13.

[128] McGuire, Exh. CRM-1T at 7:17-20.

[129] McGuire, Exh. CRM-1T at 6:19 – 7:3.

[130] Brief of Staff at 3 ¶ 9.

[131] McGuire, Exh. CRM-1T at 13:11-12.

[132] McGuire, Exh. CRM-1T at 13:13-15.

[133] Brief of Staff at 6-7 ¶ 15; Atwood, Exh. NLA-11T at 19:15-20 (*citing* Atwood, Exh. NLA-14); Atwood, TR. at 77:10 – 79:12.

Alternatively, Staff argues that, if the Company demonstrates that these projects are in service after the close of evidence in this proceeding, the Commission should only allow a prorated portion of those investments into rates based on the length the projects are in service prior to the CETA cut-off relative to the total service life of the assets.[134]

63 Staff further disagrees that the Commission's Used and Useful Policy Statement supports PSE's argument for full recovery of the capital investments in this proceeding. Staff contends that simply because the capital investments may be used and useful for some time prior to CETA's requirement to remove coal power from PSE's allocation of electricity does not mean that PSE is entitled to recover the full cost of the investment.[135] Moreover, Staff states that allowing PSE to recover costs in rates associated with projects in service after 2025 would be unreasonable and contrary to Washington law.[136] Staff further argues that it is not unfair for the Commission to require PSE to pay for costs that it is obligated to pay under its O&O Agreement, because PSE, rather than the ratepayers, had full control over whether to enter such an agreement and there is nothing unfair about requiring PSE to honor its contractual commitments.[137]

Long-Lived Plant Assets

64 Staff contends that the Commission should prorate the costs associated with ten long-lived assets because PSE has not demonstrated that the ten long-lived assets were prudent and not life extending.[138] First, Staff asserts that while the investments provide some benefit to Washington customers, the investments will not be able to provide the full benefit associated with their respective useful lives due to CETA's prohibition on coal power in PSE's allocation of electricity.[139] For support, Staff refers to the Commission's final order in Avista's 2020 GRC, where the Commission rejected Avista's request to recover costs of its Dry Ash Disposal Project because Avista had not shown that the project was not life-

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[134] Brief of Staff at 6-7 ¶ 15.

[135] Brief of Staff at 7-8 ¶ 16.

[136] Brief of Staff at 7-8 ¶ 16.

[137] Brief of Staff at 8 ¶ 17.

[138] Brief of Staff at 8-9 ¶ 19 fn. 37 (identifying the ten long-lived assets as: (1) CEM Monitor replacement for U4; (2) Scrubber Chiller replacement; (3) Windows 11 Workstation Upgrades; (4) CRO Simulator replacement, (5) Mobile Equipment replacements for 2024; (6) Replacement 3x3 Startup Transformer; (7) 3-5 Feedwater Heater; (8) Vehicle replacements for 2024; (9) EHP G Cell Liner Purchase; and (10) Cooling Tower Fill replacement for U4).

[139] Brief of Staff at 10 ¶ 22.

extending.[140] Staff maintains that because CETA prohibits coal in the Company's allocation of electricity beginning in 2026, the Company should only be authorized to recover a proportional share of costs associated with long-lived assets because they will only benefit Washington customers for a portion of their overall useful life.[141]

65 Second, Staff argues that PSE has not demonstrated a need for the ten long-lived investments. Staff notes that even though PSE voted against several capital additions during the Colstrip budgeting process, which indicates a lack of need, the Company is nonetheless seeking full recovery of those investments in this proceeding.[142] According to Staff, although PSE was obligated to pay for its proportional share of approved investments pursuant to the O&O Agreement, the existence of the agreement is not determinative as to the need for a particular investment.[143] Staff further contends that the lack of discretion to fund approved budget items under the O&O Agreement is insufficient to demonstrate need and that PSE's decision to vote against including certain long-lived assets in the Colstrip budget shows that such investments were unnecessary.[144]

66 Third, Staff maintains that PSE has not identified a valid cost-benefit analysis demonstrating that the projects are likely to produce sufficient benefits relative to the costs of the projects. Staff argues that the Commission's prior decisions in PacifiCorp's 2005 GRC and Avista's 2015 GRC establish that a utility must provide a cost-benefit analysis that quantifies tangible and intangible benefits to demonstrate that an investment is prudent.[145] Staff notes that PSE testified that whether benefits exceed costs is a relevant consideration for utility management when choosing to pursue investments and that such analysis should be from the perspective of Washington ratepayers.[146]

67 Staff also contends that, while PSE did provide a NPV calculation to demonstrate that the Company considered the costs and benefits of investments, the NPV analysis is flawed because it assumes a 100 percent probability of asset failure that will result in an outage if

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[140] Brief of Staff at 10 ¶ 23 fn. 46 (*citing WUTC v. Avista Corp*., Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021)).

[141] Brief of Staff at 11 ¶ 24.

[142] Brief of Staff at 12-13 ¶¶ 27-28.

[143] Brief of Staff at 12-13 ¶ 27.

[144] Brief of Staff at 13 ¶ 28.

[145] Brief of Staff at 13-14 ¶ 30 (*citing WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016); *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006)).

[146] Brief of Staff at 15 ¶ 32 (*citing* Atwood, TR. at 37:17-21, 38:4-7).

the investment is not pursued.[147] Staff asserts that assuming a 100 percent probability of failure if a replacement is not acquired overstates the actual probability of failure, thereby artificially increasing the benefits associated with a particular investment.[148] Staff states that PSE is unable to identify the actual probability of failure because Talen does not model the probability of failure.[149] Staff also states that PSE's NPV analysis is unreasonable because it is not from the perspective of Washington ratepayers.[150] Staff further maintains that PSE has not adequately supported its assertion that the cost of short term power would exceed the cost of further capital investment in Colstrip.[151] Finally, Staff argues that PSE has not demonstrated that it adequately presented data to management regarding decisions to pursue investments at Colstrip.[152]

SmartBurn

68 Staff initially recommended that the Commission disallow recovery of the Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner), the Unit 4 separated air over fire (SOFA) Bucket Replacement, and the Unit 4 Top Over Fire Air Bucket Replacement (TOFA), which Staff initially identified as SmartBurn components that were disallowed in PSE's 2019 GRC.[153] However, after receiving PSE's answer to BR 2, Staff revised its recommendation to support recovery for the SOFA and Boiler Burner but to disallow recovery for the TOFA component because it had been previously disallowed in PSE's 2019 GRC as a SmartBurn component.[154]

Public Counsel

69 Public Counsel asserts that PSE's attempt to seek full cost recovery of "life-extending" investments at Colstrip is improper because these investments will support Colstrip operations beyond 2025, after which CETA prohibits inclusion of coal-fired resources in PSE's allocation of electricity. Public Counsel recommends that the Commission broadly prorate all of PSE's 2024 Colstrip investments so that customers only pay for a share of

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[147] Brief of Staff at 15 ¶ 33; McGuire, Exh. CRM-1T at 20:4 - 24:4.

[148] Brief of Staff at 15-16 ¶ 34.

[149] Brief of Staff at 15-16 ¶ 34; McGuire, Exh. CRM-4 at 2.

[150] McGuire, CRM-1T at 19:6-10, 20:16 – 21:19.

[151] Brief of Staff at 17-18 ¶ 36.

[152] Brief of Staff at 16-17 ¶ 35.

[153] McGuire Exh. CRM-1T at 3:8-10, 13:22-23, 14:1-2, 14:13-18.

[154] Brief of Staff at 3 ¶ 9.

each plant addition proportional to their share of that plant's additional expected service life prior to the deadline to remove coal-fired resources from rates.[155] Public Counsel further argues that the Commission should entirely disallow the TOFA project related to SmartBurn.[156]

Used and Useful

70 Public Counsel argues that Colstrip will not be used and useful to Washington ratepayers after December 31, 2025, and that costs associated with capital additions related to Colstrip operations after that date must be excluded from rates. Stated another way, Public Counsel contends that Colstrip "capital additions can only be placed into rates to the extent they were in service to Washington customers through the end of 2025."[157] Public Counsel maintains that while the Legislature modified the Commission's ratemaking authority when it enacted CETA to allow the Commission to consider rate base that will be used and useful up to 48-months after the rate effective date, the assets must still be capable of being used for service in Washington to be included in rate base.[158]

Life-Extending Investments

71 Public Counsel states that PSE has failed to demonstrate that its investment in life-extending capital additions to Colstrip were prudent. Public Counsel argues that several capital additions that extend the useful life of Colstrip beyond December 31, 2025, when Colstrip can no longer provide coal power to PSE's Washington customers, are unreasonable and therefore imprudent.[159] Public Counsel further asserts that including costs associated with Colstrip capital assets in service beyond 2025, when Washington customers cannot benefit from those assets, results in rates that are not fair, just, reasonable, and sufficient. Public Counsel contends that including the full costs of PSE's Colstrip investments is unfair because they cannot benefit Washington customers after 2025, unjust because inclusion is contrary to CETA and the used and useful principle, and unreasonable because Colstrip provides no value to Washington customers and is harmful to the

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155 Dreyer, Exh. JMD-1CTr at 5:19 – 6:6. *See also* Dreyer, Exh. JMD-2CT at 5:1-7 (supporting AWEC's general proposal to prorate PSE's 2024 capital additions).

156 Brief of Public Counsel at 23 ¶¶ 69-70.

157 Brief of Public Counsel at 14-15 ¶ 45.

158 Brief of Public Counsel at 14-15 ¶¶ 44-45.

159 Brief of Public Counsel at 18 ¶ 55; Dreyer, Exh. JMD-1CTr at 4:23 – 5:18.

environment.[160] Public Counsel also maintains that the Company has not presented any evidence that allowing only a prorated portion of its Colstrip capital additions into rates will result in insufficient revenue for the Company to continue operating.[161] Based on its above arguments, Public Counsel recommends that the Commission allow recovery of PSE's Colstrip assets on a prorated basis.[162]

SmartBurn

72 Public Counsel recommends that the Commission disallow recovery for all four of the NOx components, including the Boiler Burner, SOFA, TOFA, and Control Room Operator (CRO) because the Commission had previously found SmartBurn to be imprudent.[163] After review of PSE's response to BR 2, Public Counsel maintains its position that SmartBurn investments that were disallowed in PSE's 2019 GRC cannot be recovered in this matter.[164] However, because only the TOFA component was disallowed in the 2019 GRC, Public Counsel now recommends the Commission disallow recovery only of the TOFA investment.

NWEC

73 NWEC makes six general recommendations regarding PSE's Colstrip investments at issue in this proceeding. First, NWEC argues that the Commission should disallow costs associated with projects that extend the life of Colstrip such that it will continue to operate past December 31, 2025.[165] Second, NWEC states that the Commission should disallow

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[160] Brief of Public Counsel at 18-19 ¶¶ 57-59.

[161] Brief of Public Counsel at 19-20 ¶ 60.

[162] Brief of Public Counsel at 24-26 ¶¶ 74-80; Dreyer, Exh. JMD-1CTr at 5:19 – 6:6.

[163] Dreyer, Exh. JMD-2CT at 3:4-8.

[164] Brief of Public Counsel at 23 ¶¶ 69-70.

[165] Cebulko, Exh. BTC-1CT at 22:1-10, 25:8-9 (identifying nine life-extending investments as (1) Scrubber Chiller Replacement; (2) CEM Monitor Replacement – U4; (3) Opacity Monitor Replacement; (4) Cooling Tower Fill Replacement U4; (5) Mercury Monitor Replacement – Unit 3; 6) Mercury Monitor Replacement – Unit 4; 7) EHP G Cell Liner Purchase; (8) PLC to DCE Obs. (Water Treatment Conversion); and (9) River Pump Motor). *See also* Brief of NWEC at 4 ¶ 10 (clarifying that NWEC also considers the four projects not used and useful prior to 2025 to also be life extending investments, bringing the total number of life-extending investments that NWEC recommends the Commission disallow to thirteen).

projects that lack a capital justification.[166] Third, NWEC asserts that the Commission should allow PSE to recover only a prorated portion of costs associated with eleven major maintenance projects.[167] Fourth, NWEC contends that the Commission should disallow costs associated with the TOFA and SOFA investments related to SmartBurn.[168] Fifth, NWEC maintains that the Commission should disallow recovery of four investments that were not placed into service in 2024.[169] Finally, similar to Staff, NWEC recommends that the Commission allow full recovery of six projects associated with human health and safety.[170]

Life-Extending Investments

74 NWEC argues that the Commission should not allow PSE to recover costs associated with life-extending investments at Colstrip. NWEC contends that PSE has not demonstrated that 13 life-extending projects are used and useful for service in Washington.[171] NWEC further asserts that the fact that PSE has entered into the A&A Agreement with NorthWestern should not influence the Commission's analysis regarding whether the assets are used and useful.[172] NWEC maintains that PSE's decision to vote against various Colstrip capital additions undermines the Company's assertion that those assets are prudent.[173] NWEC

[166] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[167] Cebulko, BTC-1CT at 28:15 – 29:1 (identifying major maintenance projects as: (1) Auxiliary Turbine Overhaul U4; (2) Turbine/Generator Base OH U4; (3) Boiler Coutant Bottom U4; (4) Air Preheater Basket Repl U4; (5) Boiler Waterwall Repl/Maint U4; (6) Air Preheater Seal Repl; (7) Workstation Upgrades (Windows 11); (8) Mobile Equipment replacements (2024); (9) Paste Plant Overflow Structure Modifications; (10) Boiler Economizer Tube Repl U4; and (11) Vehicle Replacements (2024)). Seven of NWEC's major maintenance projects are the same as the "routine maintenance" projects identified by Staff. *Compare* McGuire, Exh. CRM-1T at 23:3-7 *with* Cebulko, Exh. BTC-9CT at 8:1.

[168] Brief of NWEC at 8 ¶ 19.

[169] Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Chyenne AAQ System).

[170] *Compare* McGuire, Exh. CRM-1T at 8:14-20 *with* Cebulko, Exh. BTC-1CT at 27:7-8.

[171] Brief of NWEC at 4-5 ¶¶ 11-12. Cebulko, Exh. BTC-1CT at 9:10 – 10:2, 12:10 – 13:6.

[172] Brief of NWEC at 5 ¶ 12.

[173] Brief of NWEC at 5 ¶ 12.

requests that the Commission should articulate a prudence standard that will apply to future investments that extend the life of fossil fuel resources.[174]

Investments Lacking Capital Justification

75 NWEC additionally recommends that the Commission disallow four projects that have no capital justification in the record. NWEC notes that PSE's request for recovery in this case contains four projects that were initially non-capital projects that were subsequently transferred to capital based on financial review that do not have specific capital justification summaries.[175] NWEC inquired further about the justification for these four projects in discovery, but received a similar response from PSE, who indicated that no capital justifications were available.[176] NWEC recommends that the Commission disallow costs associated with these four projects because PSE has neither demonstrated the need for nor provided contemporaneous documentation regarding these projects.[177]

Major Maintenance

76 NWEC also recommends that the Commission prorate major maintenance projects associated with Colstrip capital investments and disallow costs amortized after 2025, consistent with the term in the Settlement Agreement in PSE's 2022 GRC regarding major maintenance, for three reasons.[178] First, NWEC states that plant investments have generally been recovered based on the expected life of the investment, and that prorating recovery of maintenance costs appropriately matches the investments costs with its expected benefits.[179] Second, NWEC contends that allowing full recovery of maintenance costs would conflict with PSE's 2014 and 2022 settlement terms regarding the amortization of major maintenance costs, which provide that major maintenance will be amortized over three years and, in the case of the 2022 settlement, that costs amortized after 2025 will not

[174] Supp. Brief of NWEC at 4 ¶ 11.

[175] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1 fn. 17).

[176] Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

[177] Cebulko, Exh. BTC-1CT at 26:6-8.

[178] Cebulko, Exh. BTC-9CT at 6:1-19; Brief of NWEC at 7-8 ¶ 17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[179] Cebulko, Exh. BTC-9CT at 6:2-11.

be recovered.[180] Finally, NWEC argues that the NPV analysis overstates the benefits from Colstrip because it overestimates the availability of Colstrip power, fails to consider the cost of capital investments in its comparison of benefits to costs, and improperly assumes that PSE's only reasonable alternative was to purchase replacement power from the market.[181] NWEC supports Staff's argument that the NPV analysis improperly assumes a 100 percent probability of failure in the event that a capital asset is not pursued.[182] NWEC further maintains that the Commission should not rely on the late disclosed analysis provided by PSE in response to BR 1 because that analysis is not risk adjusted and PSE has not shown that it was prepared contemporaneously with its decisions to invest in Colstrip.[183]

SmartBurn

77 NWEC argues that the Company has not provided any new evidence demonstrating that its SmartBurn investments have been prudently incurred.[184] NWEC also raises concerns about the Company requesting relief for an investment that has been previously disallowed by the Commission and alleged that the request places an "undue and significant burden on the Commission and intervenors" as it makes it difficult to obtain a reasonable settlement.[185]

78 NWEC contends that the Company has not provided support that distinguishes the SOFA component from the TOFA component. NWEC raises concern that "the arrows in PSE's schematic[186] identify the same part of the boiler system in attempting to delineate between TOFA and SOFA, making it impossible for the viewer to determine what, if any, difference exists between the TOFA and SOFA components."[187] NWEC recommends that the

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[180] Cebulko, Exh. BTC-1CT at 29:2 – 30:2 (*citing WUTC v. Puget Sound Energy*, Docket UE-141141, Order 04 at 3-5 ¶ 8 (Nov. 3, 2014)); Cebulko, Exh. BTC-9CT at 6:12-17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[181] Brief of NWEC at 5-6 ¶ 13; Cebulko, Exh. BTC-1CT at 13:15 – 16:16.

[182] Brief of NWEC at 6 ¶ 14 (*citing* McGuire, Exh. CRM-1T at 22:1 – 24:4).

[183] Brief of NWEC at 6-7 ¶ 16.

[184] Cebulko, Exh BTC-1CT at 18:12-15.

[185] McCloy, Exh. LCM-1T at 12:16-20.

[186] The schematic identified by NWEC was filed September 10, 2025, by the Company in response to BR 2 Attachment A and is marked confidential.

[187] Brief of NWEC at 9-10 ¶ 22.

Commission should disallow the SOFA and TOFA components as SmartBurn that has been previously disallowed.[188]

Investments Not Used and Useful in 2024

79 NWEC maintains that the Commission should fully disallow four projects with in-service dates in 2025 because PSE cannot demonstrate that these investments provided benefits to Washington ratepayers in 2024.[189] NWEC asserts that projects that come online on December 31, 2025, will never provide benefits to Washington ratepayers due to CETA's requirement to remove coal-fired resources from the allocation of electricity.[190] NWEC also argues that, if the Commission determines that the four investments not used and useful in 2024 are in fact used and useful, that the Commission should classify the projects as life-extending and disallow recovery of those investments because their useful lives exceed the three to four year useful life for major maintenance projects.[191]

Human Health and Safety Investments

80 NWEC recommends that the Commission allow PSE to recover six projects associated with human health and safety concerns.[192] NWEC states that it has reviewed the project justifications for each of the projects and found that the projects included economic metrics, including such as the internal rate of return and estimated payback period, and verified that the project descriptions supported a safety designation.[193] As such, NWEC recommends full recovery of the six human health and safety projects.[194]

AWEC

81 AWEC recommends that the Commission should prorate PSE's recovery of assets based on the portion of their service life prior to December 31, 2025, because after that date the

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[188] Brief of NWEC at 9-10 ¶ 22.

[189] Cebulko, Exh. BTC-1CT at 19:1 – 20:6. *See also* Cebulko, Exh. BTC-1CT at 19:10-11 (identifying the projects with in service dates in 2025 as: (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 feedwater heater; and (4) Northern Cheyenne AAQ System).

[190] Cebulko, Exh. BTC-1CT at 20:7-13.

[191] Brief of NWEC at 10 ¶ 24.

[192] Cebulko, Exh. BTC-1CT at 26:11 – 27:10.

[193] Cebulko, Exh. BTC-1CT at 27:1-6.

[194] Cebulko, Exh. BTC-1CT at 27:9-10.

assets are not used and useful in Washington and the Commission should disallow costs associated with the previously disallowed SmartBurn investment.

Used and Useful

82 AWEC asserts that the Commission should exclude capital projects that have an in-service date of December 31, 2025, or later under the used and useful standard, because those capital projects will not be used for service during the rate effective period.[195] Additionally, AWEC argues that the Commission should prorate PSE's recovery of life-extending investments, routine maintenance, and human safety projects, because those investments will not provide benefits to ratepayers after 2025.[196] AWEC further contends that a disallowance is appropriate given PSE's decision to enter into the A&A Agreement because the A&A Agreement obligated PSE to invest in life-extending assets that provide minimal benefit to Washington ratepayers.[197] AWEC states that any disallowance should be not be subject to cost recovery by using PTCs.[198]

SmartBurn

83 AWEC recommends that the Commission disallow all capital additions associated with SmartBurn that had been previously disallowed.[199] Specifically AWEC recommends disallowance for previously disallowed SmartBurn investments by a total of $1,039,987, which reflects only a disallowance for the TOFA component.[200]

PSE - Rebuttal

Used and Useful

84 The Company maintains that its capital investments in Colstrip satisfy the Commission's used and useful standard. Specifically, PSE argues that its investments comply with the Commission's Used and Useful Policy Statement and suggests that prorating its investments would be unjust given the Commission's prior approval of the settlement term

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[195] Brief of AWEC at 7-8 ¶ 15.

[196] Brief of AWEC at 8-9 ¶ 17.

[197] Brief of AWEC at 4-5 ¶ 9.

[198] Brief of AWEC at 4-5 ¶ 9; Mullins, Exh. BGM-1T at 4:5-9.

[199] Mullins, Exh. BGM-1T at 3:16-18.

[200] Brief of AWEC at 8 ¶ 16; Mullins, Exh. BGM-4C.

related to terminal depreciation of Colstrip assets.[201] The Company further asserts that proration of the Colstrip capital investments would be unfair, because the investments were necessary and provided a benefit to customers.[202] PSE maintains that the proposals to prorate the capital additions in this case contradict the settlement agreement in Dockets UE-170033 and UG-170034, as well as the settlement agreement in Dockets UE-220066, UG-220067, and UG-210918, because those agreements provide for terminal depreciation of the Colstrip assets.[203]

Live-Extending Investments

85 PSE asserts that the NPV analysis included in the Company's filing satisfies the Commission's prudence standard. The Company maintains that the NPV analysis reasonably reflects the costs associated with each project, risks associated with not performing the work, and the reasoning for each project.[204] PSE argues that the risk assessment reflected in the NPV analysis is appropriate because of the comparatively high cost of purchasing replacement power in the event of a temporary shut-down of Colstrip.[205] The Company further contends that, under its O&O Agreement, PSE's failure to pay its portion of Colstrip capital addition costs would have resulted in the Company defaulting on its contract and losing access to its share of electricity from Colstrip.[206] As a result of the threat of default, the Company argues that it effectively faced a 100 percent probability of failure if it failed to pay for its share of Colstrip capital addition costs. PSE further states that the Commission's prudence standard does not require a risk adjusted cost-benefit analysis in the manner proposed by Staff.[207]

Projects Not In Service Before 2025

86 PSE additionally argues that the Commission should allow the Company to recover assets that may not be in service before 2025. PSE suggests that the Commission's Used and Useful Policy Statement supports the Company's argument that the Commission has

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[201] Brief of PSE at 14-15 ¶ 26; Free, Exh. SEF-1T at 6:1 – 8:11, Atwood, Exh. NLA-11T at 18:6 – 19:20.

[202] Brief of PSE at 14-15 ¶ 26; Atwood, Exh. NLA-11T at 2:7-10.

[203] Brief of PSE at 12-14 ¶¶ 23-25; Free, Exh. SEF-1T at 6:1-21.

[204] Brief of PSE at 15 ¶ 27; Atwood, Exh. NLA-1T at 10:17 – 11:9, Exh. NLA-11T at 14:1 – 15:16.

[205] Brief of PSE at 15-16 ¶ 28; Atwood, Exh. NLA-1T at 15:7 – 16:8; Exh. NLA-11T at 14:7-12.

[206] Brief of PSE at 16-17 ¶ 29; Atwood, Exh. NLA-9.

[207] Brief of PSE at 17 ¶ 30; Atwood; Exh. NLA-11T at 11:1 – 13:6.

sufficient flexible authority under RCW 80.04.250 to permit recovery of its investments in the U4 Generator Exciter and Northern Cheyenne AAQ System.[208] The Company states that the Commission's rejection of more restrictive approaches to the inclusion of provisional capital in rates as part of the Used and Useful Policy Statement indicates that the Commission may include capital additions that are not in service by 2025 in rate base.[209]

Major Maintenance

87 PSE argues that the Commission should reject NWEC's argument to prorate or disallow major maintenance capital costs based on PSE's 2014 and 2022 settlements because those settlements do not apply to major maintenance capital costs. PSE maintains that major maintenance events result in two types of costs, capital costs and operations and maintenance (O&M) costs.[210] PSE asserts that the 2014 settlement only pertains to the O&M costs associated with major maintenance events, and that NWEC is attempting to improperly apply that settlement term to major maintenance capital costs.[211] However, while PSE contends that the 2014 settlement term does not apply to the capital maintenance costs, it states that the major maintenance amortization treatment in the 2014 settlement has the same effect as prorating the major maintenance capital costs.[212] PSE further argues that the 2022 settlement term regarding major maintenance amortization only pertains to the amortization of major maintenance O&M costs, not major maintenance capital costs, similar to the 2014 settlement.[213]

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[208] Brief of PSE at 21-22 ¶¶ 38-39; Atwood, NLA-11T at 17:18 – 19:20.

[209] Brief of PSE at 22 ¶ 39.

[210] Free, Exh. SEF-1T at 12:10-11.

[211] Free, Exh. SEF-1T at 13:3-8.

[212] Free, Exh. SEF-1T at 13:14-17 ("In other words – the treatment Mr. Cebulko and parties recommend for pro-rating PSE's capital costs is the same as the major maintenance *amortization* treatment agreed to in PSE's 2014 PCORC. Therefore, no correction to the calculation of Mr. Cebulko's proposed adjustment is needed.") (emphasis in original).

[213] Brief of PSE at 14-15 ¶ 26 fn.61; Free, TR. at 115:25 – 118:8. *See also* Free, TR. at 119:5-14 ("A: I believe that the way my exhibits were laid out in [PSE's 2022 GRC], the contested adjustment was only related to the O&M portion of major maintenance. That's deferred. Not the capital. And we settled that adjustment. So in my mind that makes it clear. Q: All right. So what you're saying is you only settled the operation/maintenance portion, not the capitalized portion? A: Correct.").

SmartBurn

88 The Company is seeking recovery of investments to components of its NOx control system. Specifically, the Boiler Burner, SOFA, and TOFA components of the combustion control system, which are commonly referred to as SmartBurn by the Colstrip operator and within plant budgets.[214] PSE alleges that there has been a misunderstanding as to what is the SmartBurn equipment that was disallowed in PSE's 2019 GRC because SmartBurn is a company and not a singular piece of equipment. [215] For regulatory purposes, PSE clarifies that the only components of the NOx control system that was disallowed as SmartBurn in PSE's 2019 GRC was the TOFA. The SOFA and Boiler Burners existed prior to the SmartBurn technology installation.[216] The Boiler Burner was installed prior to 2007, the SOFA on Unit 3 was installed in 2007, and on Unit 4 in 2009.[217] PSE concedes that the Company incorrectly identified the SOFA, TOFA, and Boiler Burners as SmartBurn in a data request response to Staff.[218] On cross-examination, although the Boiler Management System (BMS) was updated by SmartBurn in 2017, the plant would still need a BMS, regardless of who installed it.[219] PSE is not seeking any recovery related to the BMS in this docket.[220] Atwood alleges that the "CRO Simulator is not specific to the operation of SOFA-installed SmartBurn equipment only" and that the CRO would have been installed without a SmartBurn investment so it should not be disallowed.[221]

89 PSE is seeking recovery for the TOFA SmartBurn component even though it had previously been disallowed because the TOFA is "an integrated part of the Combustion Control system, and the plant cannot run without it."[222] Specifically:

> [t]he pieces of the combustion system work together to operate the Units efficiently by avoiding slagging, maintaining steam temperature, avoiding metal heat fatigue, and other goals, while also maintaining environmental compliance standards. TOFA, SOFA, burners, and other equipment all have to be maintained on a regular basis when in constant contact with heat and

[214] Atwood, Exh. NLA-11T at 4:12-18.

[215] Atwood, Exh. NLA-11T at 5:4-8.

[216] Atwood, Exh. NLA-11T at 5:15-22; Atwood, TR. at 39:21-25; Atwood, Exh. NLA-12.

[217] PSE's Response to BR 2.

[218] Atwood, Exh. NLA-11T at 5:22, 6:1-3; Exh. NLA-7C.

[219] Atwood, TR. at 40:14-20.

[220] Atwood, Exh. NLA-19X at 1.

[221] Atwood, Exh. NLA-11T at 7:3-5, 13-15.

[222] Atwood, Exh. NLA-11T at 6:5-9.

> corrosive conditions. Consequently, PSE should be allowed to recover the investment made in these systems and equipment.[223]

90 PSE argues that its investments in SmartBurn are prudent and are used and useful, and requests that the Commission grant full recovery.[224] Although the Commission previously disallowed the TOFA component, the Company argues that a previous disallowance is not a "blanket, forward-looking" ban and that the Commission should base its decision on the record in this proceeding and asks the Commission to consider whether the SmartBurn investments in "2024 were prudently incurred and confer commensurate benefits to Washington customers in the rate period[.]"[225]

Commission Determination

91 Before investments may be recovered in rates, the Commission must determine that the costs associated with investments a utility seeks to recover are used and useful for service in this state.[226] Similarly, costs may only be included in rates if the Commission determines those investments are prudent.[227] As such, the Commission review of a utility's requested rate recovery encompasses both the question of whether investments are used and useful and the question of whether the associated costs are prudent.[228] The Commission now proceeds to consider whether the investments that PSE has included in rates for recovery are used and useful and then considers whether the costs that it seeks to recover are prudent.

A. Used and Useful

92 RCW 80.04.250 states in part:

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223 Atwood, Exh. NLA-11T at 6:10-16.

224 Brief of PSE at 17-18 ¶ 31.

225 Brief of PSE at 17-18 ¶ 31.

226 *WUTC v. PacifiCorp,* Docket UE-050684, Order 04 at 21-22 ¶ 50 (Apr. 17, 2006).

227 *WUTC v. Puget Sound Energy*, Docket UE-031725, Order 14 at 20-21 ¶ 37 (May 13, 2004) ("Any costs determined to be unreasonable or imprudent in such proceedings are subject to disallowance.").

228 *See also* Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020) ("In sum, this Policy Statement establishes a two-step approval process. The first step involves provisional approval for the inclusion in rates of identified rate-effective period investment. The second step involves final approval after the investments are reviewed and confirmed to be used and useful and prudent.").

> (1) The provisions of this section are necessary to ensure that the commission has sufficient flexible authority to determine the value of utility property for rate making purposes and to implement the requirements and full intent of chapter 288, Laws of 2019.
>
> (2) The commission has power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period and shall exercise such power whenever it deems such valuation or determination necessary or proper under any of the provisions of this title. The valuation may include consideration of any property of the public service company acquired or constructed by or during the rate effective period, including the reasonable costs of construction work in progress, to the extent that the commission finds that such an inclusion is in the public interest and will yield fair, just, reasonable, and sufficient rates.
>
> (3) The commission may provide changes to rates under this section for up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates. The commission must establish an appropriate process to identify, review, and approve public service company property that becomes used and useful for service in this state after the rate effective date.

The Commission further observes that this language reflects amendments the Legislature made during consideration of CETA, and those amendments are found in chapter 288, Laws of 2019, the same legislation that enacted CETA.[229]

93 In interpreting the phrase "used and useful," the Washington State Supreme Court has explained "'Used' is defined as 'employed in accomplishing something'; 'useful' is defined as 'capable of being put to use: having utility: advantageous: producing or having the power to produce good: serviceable for a beneficial end or object.'"[230] The Court further explained "RCW 80.04.250 empowers the Commission to determine, for ratemaking purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington."[231] By extension, "[w]hen calculating a utility's rate base for ratemaking, if the WUTC considers utility plant that 'is neither employed for service nor capable of being put to use for service; . . . such plant is

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[229] See, e.g., RCW 19.405.010 (reflecting the title "Findings – Intent – 2019 c 288").

[230] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984) (*citing Webster's Third New International Dictionary* 2524 (1976)).

[231] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984).

not 'used and useful' for service' and the [Commission] exceeds its statutory authority."[232] The Commission has also previously interpreted "the phrase 'used and useful for service in this state' to mean benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[233]

94 However, the Commission's inquiry regarding the used and useful standard is further informed by the requirements of CETA. Specifically, RCW 19.405.030(1) states that "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation." RCW 19.405.020(1) further defines "allocation of electricity" as, "for the purpose of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state." As such, RCW 19.405.030(1) prohibits a utility from including the benefits and costs associated with coal power in its retail customer electricity rates after December 31, 2025, other than costs associated with decommissioning and remediation.

95 As CETA requires that PSE remove the benefits and costs of coal power from its retail customer rates as of January 1, 2026, the Commission determines that costs associated with capital investments in Colstrip based on benefits that are realized after 2025 must be excluded from rates. The Commission generally agrees with the non-company parties that this outcome may be achieved by prorating the Company's recovery of costs based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity.

96 The Commission disagrees with PSE's argument that the 2017 and 2022 GRC settlements support the Company's request for full recovery of its assets or that proration would be unjust because it contradicts those settlements. Regarding the 2017 GRC settlement, the Commission observes that this settlement was approved prior to the enactment of CETA. Insofar as the 2017 GRC settlement did not contemplate the additional requirements under CETA, the Commission is not persuaded that settlement controls the Commission's analysis in this proceeding. Furthermore, review of the order approving the 2017 GRC settlement indicates that the terms regarding depreciation only apply to those investments that were known at the time of the settlement:

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[232] *Ofc. of the Atty. Gen., Pub. Counsel Unit v. Wash. Utils. & Transp. Comm'n*, 4 Wn. App. 2d 657, 682 (2018) (quoting *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984)).

[233] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 21-22 ¶ 50 (Apr. 17, 2006).

> Balancing PSE's interest in recovering **all of the net plant amounts remaining on its books for the Colstrip units as of September 30, 2016**, against the Settling Parties' common interest in protecting ratepayers from significant rate impacts and avoiding intergenerational inequities, the Settlement Stipulation establishes two new accounts.
>
> . . .
>
> In the final analysis, we determine that the Settlement Stipulation takes advantage of the unique circumstances in which PSE, without significant rate impacts, is able to recover fully the undepreciated Colstrip plant balances **on the Company's books** on significantly shortened depreciation schedules tied to the known retirement date for Units 1 & 2 and a well-considered change for Units 3 & 4.[234]

As such, as the assets on issue in this proceeding were not "on the Company's books" at the time of the 2017 GRC settlement, the Commission does not interpret that settlement as presently controlling.

97 Turning to the 2022 GRC settlement, while PSE is correct that the record reflects that the settling parties in that case contemplated terminal depreciation,[235] the settlement also expressly provides for additional review of investments related to Colstrip:

> j. Colstrip. PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed in the testimony of Susan E. Free (Exh. SEF-18). PSE agrees to exclude capital investments associated with the construction of PSE's Colstrip dry ash facilities from recovery in base rates in this case and PSE's proposed Schedule 141-C tracker. **The Settling Parties agree that Colstrip costs included in rates in 2023 and beyond (including major maintenance expense and new plant additions) are subject to review, including but not limited to an examination of prudence, in PSE's annual Schedule 141-C tariff filing.** Major maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates. **The Settling Parties retain all rights to challenge Colstrip costs when PSE files tariff revision for the tracker**.[236]

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[234] *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034 (*consolidated*), Order 08 at 40, 50-51 ¶¶ 111, 136 (Dec. 5, 2017) (emphasis added, internal citations omitted).

[235] Free, Exh. SEF-1T at 6:1-21; Free, TR. at 115:12 – 116:13.

[236] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (emphasis added).

Given that the 2022 GRC settlement clearly preserved the parties' ability to challenge the inclusion of subsequent costs related to Colstrip in a future proceeding, PSE cannot reasonably rely on the 2022 GRC settlement as requiring the inclusion of all Colstrip costs at issue in this proceeding. The 2022 GRC settlement did not preapprove any of the assets that are currently before the Commission for review and does not preclude the Commission from disallowing costs that fail to satisfy applicable legal standards on a prorated basis.

98 The Commission further disagrees with PSE's assertion that prorating its recovery in this case would be unfair and contrary to the Commission's Used and Useful Policy Statement. The Used and Useful Policy Statement states in part that "rates must be fair to both customers and the public service company[.]"[237] Although the Company maintains that it would be unfair to prorate the recovery of its Colstrip investments because it was obligated by its ownership agreement to fund its full share of those assets, that agreement was entered into at the discretion of PSE and PSE's customers had no control over whether to accept those terms. To the extent that PSE argues that it lacks discretion because of the O&O Agreement, that lack of discretion was created by PSE's own actions. The Commission also rejects PSE's argument that Washington customers will receive the full benefit of Colstrip costs associated with capital projects and maintenance regimes that extend past the CETA deadline to remove coal from the allocation of electricity.[238] As the Company stated at hearing, Colstrip provides no benefit to ratepayers after 2025:

> Q: So if you could look at your rebuttal testimony at Page 11, Lines 11 to 13. Actually, 13 to 14. And it indicates that, in response to AWEC's testimony, that as of December 31st, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public; is that correct?
>
> A: That is correct.[239]

99 Witness Atwood similarly testified:

> Q: Just to clarify: CETA requires that coal be out of rates effective December 31st, 2025. Is that your understanding?
>
> A: Yes.

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[237] Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020).

[238] Atwood, Exh. NLA-1T at 20:4-6.

[239] Roberts, TR. at 103:23 – 104:4. *See also* Roberts, Exh. RJR-1T at 11:13-14 ("As of December 31, 2025, as AWEC knows, Colstrip is not necessary or useful in the performance of any PSE duties to the public.").

> Q: And so after that date, coal plant will not be used to serve Washington ratepayers; is that correct?
>
> A: It will not be operational to serve customers, PSE customers.
>
> Q: In Washington?
>
> A: Yes.
>
> . . .
>
> Q: Is the Colstrip plant after December 31st, 2025, worth anything to Washington customers?
>
> A: Puget Sound Energy cannot have it in its rates. By getting out of the plant at the end of the required timeline, Washington customers benefit from a cleaner portfolio.
>
> Q: Okay. So there's a benefit. But in terms of the actual output of Colstrip, is there any value to Washington customers after that date?
>
> A: There will not be benefit of operating after that date, no.[240]

100 While the Commission must carefully evaluate the needs of both customers and the Company, the Commission does not find that it would be fair to require Washington customers to bear the full costs of assets from which they will only receive a fraction of the benefits relative to those assets' useful lives. Rather, prorating the assets based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity appropriately assigns fair costs to ratepayers relative to the benefit they actually receive from the Colstrip assets.[241]

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[240] Atwood, TR. at 56:7-16, 76:1-12. The Commission notes that while the witness did further respond that "Well, the [Colstrip] power will be on the grid" and that "would potentially be a benefit in some way," this assertion is speculative and conflicts with the witness's earlier statement that Colstrip could not serve Washington customers after 2025. Atwood, TR. at 76:16 – 77:7.

[241] On the issue of fairness, the Commission also notes that the Company was aware of the possibility that certain Colstrip assets may be subject to disallowance as part of this proceeding. *See* Roberts, Exh. RJR-1T at 13:10-12 (explaining that PSE voted no on certain budget items in part because "PSE felt that the possibility of a disallowance by the Commission would leave the Company in a difficult negotiating position with NorthWestern should PSE not have some logic to its No votes.").

i. Human Health and Safety Investments

101 However, the Commission determines that the six human health and safety projects should be fully recovered by PSE because they provide a benefit beyond facilitating the generation of electricity.[242] As testified to by Staff, these projects were intended to address employee health and safety hazards related to Colstrip operations:

> Two of the projects (the Snubber Rebuild and the Hot Reheat Elbow Replacement) address risks associated with damaged or out-of-code high-pressure steam lines where failure of the existing equipment could result in the release of 1000 degree high-pressure steam onto the turbine deck, one of the projects (the switchgear mod) is necessary for code compliance and addresses the risks that plant personnel will be exposed to high-energy arc flash events, and one of the projects (the coal pipe replacement) addresses coal pipe leaks which increase the risks of explosions and create employee health hazards such as an elevated risk of silicosis, pneumonia, and black lung.
>
> . . .
>
> The boiler scaffolding provides a safe structural environment during boiler inspections and repairs, and the boiler elevator allows large and heavy equipment to be safely moved to various locations on the boiler.[243]

102 The Commission agrees with Staff's assessment that the "near-term benefits of th[e]se projects exceed the cost of their investment," and determines that they should be fully included in rates.[244] The Company's ratepayers benefit from reasonable human safety investments that reduce the Company's risk of liability in the event of an incident resulting in injury or death to plant workers. Absent such investment, investors may be led to perceive the Company as relatively riskier, which could in turn require a greater degree of compensation to investors to account for that risk, thereby increasing overall future rates to customers.[245] Although utilities must transition away from certain resources to comply with CETA, the Commission does not want to create an incentive for utilities to avoid reasonable safety investments for such resources that place workers in threat of harm,

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[242] Specifically, the six human safety projects are (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[243] McGuire, Exh. CRM-1T at 10:4-19 (citations omitted). *See also* Cebulko, Exh. BTC-1CT at 26:9 – 27:10 (recommending full recovery of the same six human safety projects).

[244] McGuire, Exh. CRM-1T at 11:2-5.

[245] RCW 19.405.010(2) ("In implementing this chapter, the state must . . . provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

which generally would be contrary to the public interest.[246] The Commission has no desire to see the transformation of Washington's energy supply to clean energy built upon a foundation of unnecessary hazards and risk of harm to workers.

ii. Assets with 2025 In-Service Dates

103 With respect to assets with in-service dates in 2025, the Commission determines that such assets should be prorated consistent with the Commission's used and useful analysis discussed above. Regarding the U4 Generator Exciter and the Northern Cheyenne AAQ System, the Commission finds that PSE should be required, as a condition of compliance with this order, to make a supplemental filing indicating when these two investments were placed into service. If these investments were placed into service on or before December 31, 2025, the Company should be allowed to recover a pro rata portion of these investments for two reasons. First, to the extent that these assets are placed into service on or before the deadline to remove coal from rates, they have provided some benefit to Washington customers that warrants proportional recovery in the interest of fairness. Second, because CETA requires that coal power be removed from PSE's allocation of electricity after 2025, PSE will not have another opportunity to recover these costs in a subsequent proceeding. As such, the Commission exercises its discretion to require PSE to file an update to the record as a condition of compliance with this order due to the requirements of CETA but cautions that this unique situation should not be interpreted as setting a general precedent for future GRCs.

B. Prudence

104 During GRC proceedings, the Commission determines the prudence of utility expenditures by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[247] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[248]

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[246] *See,* RCW 19.405.010(4)(" The legislature finds that Washington can accomplish the goals of chapter 288, Laws of 2019 while: . . . maintaining safe and reliable electricity to all customers at stable and affordable rates[.]"); RCW 80.28.425(1) (stating in part ""[i]n determining the public interest, the commission may consider such factors including, but not limited to, . . . health and safety concerns . . . to the extent such factors affect the rates, services, or practices of a[n] . . . electrical company.").

[247] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

[248] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives that the Commission might find prudent.[249] The prudence review "requires evaluation of the Company's decisions not just from the perspective of management for the benefit of shareholders, but also for the benefit of customers."[250] The fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company.[251]

105 The prudence standard applies to both the question of need and the appropriateness of the expenditure.[252] The Commission considers three broad questions when evaluating prudence: (1) Was the initiation of the project prudent; (2) Was the continued implementation of the project prudent; and (3) Were the expenses prudently incurred?[253] The second and third factors are examined using the same prudence test as the first factor, but applied at a different point in time and necessarily premised on a reevaluation of the project.[254] Consequently, the Commission's prudency review is not limited to a single point in time and encompasses the implementation and construction phases of a project to ensure that a regulated utility continues to reasonably control and evaluate a project.

106 As noted above, when evaluating prudence, the Commission reviews utility decision-making at the time decisions were made. Stated differently, the Commission will not use the benefit of hindsight when evaluating prudence.[255] Consequently, regulated utilities are required to maintain contemporaneous records of their decision-making process and analysis to satisfy the Commission's prudency standard.[256] A utility's "robust discussions" about a project, with a "consensus" on decisions, is not sufficient to demonstrate

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[249] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705 (*consolidated*), Order 11 at 119 ¶ 337 (Apr. 2, 2010).

[250] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004).

[251] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004) (*quoting* Goodman, The Process of Ratemaking, at 857).

[252] *WUTC v. PacifiCorp*, Docket UE-152253, Order 12 at 33 ¶ 94 (Sept. 1, 2016).

[253] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

[254] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

[255] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 94 (Sept. 1, 2016).

[256] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order, at 15-16 (Sept. 27, 1994) ("The company's lack of contemporaneous evaluation and documentation is, at best, poor management practice."); *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 36 ¶ 102 (Sept. 1, 2016) ("However, this memo was prepared after the final decision to proceed was made, and therefore cannot be shown to have played a part in the Company's decision-making.").

prudence.[257] Rather, "the parties and Commission should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented."[258] "Documentation and evidence of prudence decision making must be kept contemporaneously with a company's decision making or the Commission's ability to evaluate prudence is thwarted."[259]

107 The Commission has previously explained that its review of prudence typically focuses on four factors:

> 1) *The Need for the Resource:* The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> 2) *Evaluation of Alternatives:* The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> 3) *Communication With and Involvement of the Company's Board of Directors:* The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.
>
> 4) *Adequate Documentation:* The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[260]

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[257] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[258] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[259] *In re Investigation Regarding Prudency of Outage and Replacement Power Costs*, Docket UE-190882, Order 5 at 12 ¶ 43 (Mar. 20, 2020).

[260] *WUTC v. Puget Sound Energy*, Dockets UE-111048 & UG-111049 (*consolidated*), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

108 As stated above, the Commission has already disallowed the costs associated with Colstrip investment assets' remaining useful lives after 2025 based on those portions of the assets not providing any service or benefit to Washington customers. Consequently, the Commission's prudence review is limited to the remaining portions of those costs.

109 The Commission finds that the Company has sufficiently demonstrated that the remaining portions of the assets and costs it seeks to include in rates are prudent.[261] With regard to the question of need, PSE has made a reasonable showing of the need for the assets based on the analysis prepared by the Colstrip operator and the forecasted costs of replacement power.[262] The Commission is not persuaded that the Company's decision to vote "no" on certain capital investments is evidence of a lack of need, as the Company's voting strategy can be informed by several considerations, including CETA compliance and prior Commission orders.[263] The Commission also disagrees that investments that extend the life of Colstrip are categorically prohibited under the prudence standard. Both Staff and NWEC cite to the Commission's order in Avista's 2020 GRC to support their argument that investments that extend the life of Colstrip must be excluded from the Company's rates.[264] However, the Commission's consideration of whether the Dry Ash Disposal project was life extending was a product of Avista's settlement obligations from a prior GRC, not a component of the Commission's general prudence standard.[265]

110 The Commission also rejects the premise that the prudence standard requires a specific form of cost-benefit analysis. While a utility must include some form of analysis as part of its demonstration of need and consideration of alternatives, the Commission does not require a particular type of analysis under the general prudence standard, leaving the utility with discretion to develop a cost analysis that is reasonable under the circumstances. The Commission finds that the discussion of the prudence of Avista's advanced metering infrastructure investment in the first Avista 2015 GRC order is distinguishable, as in that

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[261] The Commission declines AWEC's invitation to articulate a prudence standard regarding all investments that extend the life of fossil fuel resources that departs from its longstanding prudence framework. The Commission is not persuaded that a modification of its well-established standard is necessary or warranted.

[262] Atwood, Exh. NLA-7C.

[263] Roberts, Exh. RJR-1T at 13:10-12.

[264] Brief of Staff at 10 ¶ 23; Brief of NWEC at 6 ¶ 15.

[265] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021) ("Lastly, we are uncertain that Dry Ash is not a life-extending capital addition. Our 2019 Avista GRC Final Order approved a settlement that included an agreement by Avista not to support capital expenditures beyond routine capital maintenance costs that would extend Colstrip's operational life beyond December 31, 2025.").

case Avista had not yet implemented its AMI program and the prudence of AMI was not sufficiently ripe for adjudication.[266] However, the first Avista 2015 GRC order does highlight the fact that, while the Commission will not "preapprove" a particular type of analysis to support prudence, a utility risks a disallowance if it presents an analysis that has insufficient detail or otherwise lacks credibility.[267] Additionally, the Commission's discussion in PacifiCorp's 2005 GRC regarding the demonstration of "tangible and quantifiable benefits to Washington of resources in the system," was in the context of reviewing PacifiCorp's interjurisdictional allocation methodology, rather than as part of a prudence review.[268]

111 However, the Commission agrees that the O&O Agreement does not independently satisfy the required showing of need under the prudence standard. While the O&O Agreement creates an obligation for PSE to pay for its proportional share of budget items that are approved by the Colstrip owners, the owners' approval is not determinative of whether a utility has demonstrated a reasonable need. If the fact that PSE is required to fund its portion of investments pursuant to a contract were all that is necessary to demonstrate need, the need would be met for every Colstrip asset approved, which would effectively nullify the Commission's prudency review. Furthermore, the Commission has previously disallowed Colstrip assets that the owners voted to approve based on a finding of lack of need, such as the Commission's previous SmartBurn disallowance, which further supports a determination that the O&O Agreement's obligation to pay does not, by itself, satisfy the need component of the prudence standard.[269]

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[266] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 71 ¶ 199 (Jan. 6, 2016)("In conclusion, we decline to rule on the prudency of Avista's proposed AMI investment in this case because the issue is not ripe for our determination. This decision should not be interpreted as a rejection of AMI. The Company must decide what metering program provides ratepayers the most benefit at the least cost.").

[267] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016) ("While we do not make a decision regarding the prudence of this project in this proceeding, we note the considerable uncertainty surrounding the business case analysis Avista prepared. . . . We look forward to a more refined cost-benefit analysis in a future proceeding, including a fuller discussion of "non-quantifiable benefits" suggested by Mr. Kopzcynski.").

[268] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006).

[269] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 98 ¶ 274 (Sept. 27, 2021) (disallowing SmartBurn investment in Colstrip because the utility "failed to demonstrate that SmartBurn was necessary and failed to produce documentation sufficient to demonstrate that its costs were prudently incurred.").

112 Turning to the NPV analysis supporting PSE's Colstrip costs in this case, the Commission agrees with the non-company parties that the analysis is questionable in some respects. Although the Commission agrees that PSE's failure to fund an approved capital investment will result in default under the O&O Agreement, the record does not indicate that Talen's decision to assume 100 percent probability of failure was intended to reflect a shareholder's default.[270] However, while the persuasiveness of the NPV analysis is weakened by the fact that the analysis is not risk adjusted, the Commission is not persuaded that this condition makes the analysis wholly unreliable.

113 Additionally, in light of the Commission's above analysis excluding the portions of Colstrip investments not used and useful in Washington after 2025, the Commission finds that the NPV analysis is sufficiently reasonable even though it is not performed from the perspective of Washington ratepayers. While the Commission will not proscribe the type of analysis that a utility may utilize to support its showing of prudence, if such analysis is based on general rather than Washington-specific data, the utility should be able to explain how that data supports prudence from the perspective of Washington ratepayers. In some cases, there may be no distinction between the general benefit and the Washington specific benefit, insofar as the Washington benefit is a proportional share of the general benefit. But, in circumstances where the Washington benefit may materially diverge from the general benefit, such as when a resource may no longer be used to provide service in Washington, further analysis should be performed to verify that the investment is still prudent with respect to Washington ratepayers.

114 Based on the above discussion, the Commission finds that the Company has demonstrated a need for the prorated portions of the Colstrip assets in this case based on the NPV analysis and forecasted replacement power costs.[271] The same evidence also supports a finding that the Company considered alternatives to continuing to fund Colstrip and that it documented its reasoning contemporaneously. The record also demonstrates that the Company informed and consulted with its management about the investment decisions related to Colstrip.[272]

115 As to the equity considerations raised by Public Counsel regarding PSE's full inclusion of Colstrip costs, the Commission has addressed this issue by prorating PSE's recovery of

[270] Atwood, Exh. NLA-7C; Exh. NLA-9.

[271] Atwood, Exh. NLA-7C.

[272] Atwood, Exh. NLA-1T at 20:8-17; De Villiers, Exh. SDV-3C, Attach. A.

Colstrip costs.[273] Prorating PSE's recovery of investments in Colstrip promotes equity by appropriately assigning costs to Washington customers relative to the benefits that they will receive before coal-fired resources can no longer be included in PSE's allocation of electricity. The Commission's analysis in this matter is also informed by the numerous public comments filed in this docket raising concerns about affordability and opposing continued support for coal-fired resource operations past 2025 despite CETA's mandate to remove coal from the allocation of electricity.[274]

i. SmartBurn

116 In this docket, PSE is seeking recovery for costs associated with four components of the NOx control system:

- Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner)
- Unit 4 Separated Over Fire Air Bucket Replacement (SOFA)
- Unit 4 Top Over Fire Air Bucket Replacement (TOFA)
- Control Room Operator (CRO)[275]

117 Although the Commission finds general prudence in PSE's Colstrip investments, the Commission finds that specific Company investments labelled "SmartBurn" were not prudently incurred because the Company did not demonstrate that the investments were necessary, based on the Commission's prior disallowance of certain SmartBurn investments.[276]

118 In PSE's 2019 GRC, the Commission disallowed recovery of investments in SmartBurn technology that is associated with the NOx Combustion Control system after the Commission found that "PSE failed to demonstrate that the costs related to PSE's

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[273] Brief of Public Counsel at 20-22 ¶¶ 61-68; *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 09 at 19-20 ¶ 59 (Aug. 23, 2022) (retaining discretion to evaluate equity on a case-by-case basis). However, the Commission declines to consider the articles cited by Public Counsel in its briefing, as those articles are not part of the record in this case, and Public Counsel has not motioned for the Commission to take official notice of those articles or explained why they could not have been previously submitted to the record.

[274] *See generally* BR 5, Public Comment Exhibit.

[275] Atwood, Exh NLA-11T at 4:12-19, 7:3-12.

[276] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

SmartBurn investment were prudently incurred[,]"[277] In particular, the Commission found that PSE failed to demonstrate that SmartBurn was necessary and "failed to maintain appropriate documentation of its decision to install SmartBurn."[278] During the initial rounds of testimony in this docket, the parties were not clear on what components of the NOx control system were related to the SmartBurn investments the Commission previously disallowed in PSE's 2019 GRC. In response to DR 19 from NWEC, the Company identified the Boiler Burner, SOFA, and TOFA as SmartBurn technology.[279] However, PSE clarified that the only component of the NOx control system that had been previously disallowed was the TOFA component.[280] The Company confirms that the Boiler Burner and SOFA investments on Units 3 and 4 were installed prior to 2016 and were not part of the 2019 GRC.[281]

119 Because PSE's investment in the SmartBurn TOFA component of the NOx control system has been previously disallowed as imprudent, we analyze PSE's request for recovery for investment in replacing the TOFA component for prudence. The Company has argued that although the Commission disallowed recovery of its investment in the TOFA component in the 2019 GRC, that should not influence the Commission's decision in this matter, and the Commission should only look to the record in this docket and not a previous docket to determine prudence.

120 In determining whether an investment was prudently incurred, we consider what the Company knew at the time it made the investment. The Company was aware that the Commission had previously found its costs related to investment in SmartBurn/TOFA to be imprudently incurred at the time it invested in the replacement component.[282] We can understand the Company's concerns that that the TOFA component is an integrated part of the NOx control system and that the TOFA replacement was necessary because the plant

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[277] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[278] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[279] Cebulko, Exh. BTC-6.

[280] PSE's Response to BR 2 at 2 (September 10, 2025); PSE's Revised Response to BR 6 at 1 (October 30, 2025).

[281] PSE's Response to BR 5 at 2 (October 27, 2025).

[282] *See WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶¶ 197-199 (Jul. 8, 2020).

cannot run without it. However, the Company has not provided additional documentation to demonstrate prudence in its TOFA investment, thus there is not sufficient information in the record to persuade us that the Company's investment was prudently incurred. Because the Company's investment in relation to the SmartBurn TOFA component is not prudent, we find that the Commission should disallow cost recovery related to the TOFA component.

121 The Company clarified that the CRO, Boiler Burner, and SOFA components were installed in the NOx control system prior to its 2019 GRC and were not subject to the decision in that order. Further, the Company has conceded that the TOFA component was disallowed as imprudent.[283]

122 We find the installation timeline of the SOFA component provided by the Company sufficiently rebuts NWEC's argument because it demonstrates that SOFA was installed on Colstrip Units 3 and 4 in 2007 and 2009 respectively, and was not subject to the 2019 GRC decision.[284] Because the Boiler Burner, CRO, and SOFA components of the NOx control system were not subject to PSE's 2019 GRC, we do not find that recovery on investment for these components was disallowed in PSE's 2019 GRC. The Boiler Burner, CRO and SOFA are not subject to the same analysis as the TOFA component but are subject to the Commission's pro-rata analysis in the Used and Useful section of this order above.

ii. *Assets Lacking Capital Justification*

123 The Commission further determines that PSE has not demonstrated the prudence of four investments that lack capital justification.[285] As noted by NWEC, the Company has stated in both testimony and in response to discovery that there are no capital justifications for four projects, and those projects are not discussed in the Company's NPV analysis.[286] As such, the Commission determines that the Company has not demonstrated the need for these investments or provided contemporaneous documentation with respect to its decision to pursue these investments, and has not demonstrated that they are prudent.

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[283] Brief of PSE at 18-19 ¶ 32.

[284] PSE's Response to BR 2.

[285] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[286] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1, fn. 17); Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

V. Operations & Maintenance Amortization

124 Staff contests a portion of PSE's major maintenance amortization expenses related to the 2024 Unit 4 outage. Staff explains that PSE has included a total major maintenance amortization expense of $4,201,653 related to four separate Colstrip outages, with the 2024 Unit 4 outage accounting for $1,609,006.[287] Staff contends that dividing the total 2024 Unit 4 outage cost of $4,471,694 by 36-months should result in a monthly amortization expense of $124,214, but PSE has included a monthly amortization expense of $134,048 in its filing.[288] Based on a monthly amortization cost of $124,214, Staff maintains that the annual amortization associated with the 2024 Unit 4 outage should be $1,490,565.[289] Staff recommends that the Commission reduce the annual major maintenance amortization expense included in rates from $1,609,006 to $1,490,565.[290]

125 PSE maintains that while Staff's methodology for calculating the annual amortization expense is correct, it is based on an incorrect total event cost for the 2024 Unit 4 outage.[291] The Company asserts that $4,471,694 included in its original filing was based on a preliminary amount rather than the final amount, and that the correct costs associated with the 2024 Unit 4 outage is $4,809,523.[292] Based on the correct amount, PSE argues that the correct total amortization for the 2024 Unit 4 outage is $1,603,174.[293]

Commission Determination

126 The Commission agrees with PSE's updated calculation of the annual amortization expense associated with the 2024 Unit 4 outage. PSE's updated calculation on rebuttal is based on the actual cost of the 2024 Unit 4 outage, rather than the preliminary estimate that was included in the Company's initial filing. As such, the amount associated with the annual amortization associated with the 2024 Unit 4 outage should be corrected from $1,609,006 to $1,603,174. The Commission further determines that major maintenance operations and

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[287] McGuire, Exh. CRM-1T at 36:11-18.

[288] McGuire, Exh. CRM-1T at 37:10-16.

[289] McGuire, Exh. CRM-1T at 37:17-20.

[290] McGuire, Exh. CRM-1T at 37:22 – 38:4.

[291] Free, Exh. SEF-1T at 11:1-4.

[292] Free, Exh. SEF-1T at 11:4-10.

[293] Free, Exh. SEF-1T at 11:11 – 12:2.

maintenance expenses should be recovered consistent with the terms of PSE's 2022 GRC settlement.[294]

VI. Refund Process

127 Although PSE maintains that no refund is necessary, if the Commission does require a refund, the Company recommends that the Commission require the Company to either provide a refund directly to customers or apply the refund against PTCs.[295] PSE raises concerns that CETA's requirement to remove coal from its allocation of electricity after 2025 could be interpreted to prohibit a direct refund to customers through Schedule 141COL.[296] If the Commission determines that a direct refund is not permitted under CETA, the Company recommends applying the refund against its PTCs and states that customers would still be compensated for the time value of money because they would offset rate base in the Colstrip Tracker.[297]

128 Staff recommends that the Commission require the Company to directly refund any over collected amounts through PSE's Schedule 141COL beginning in 2026.[298] Specifically, Staff argues that the Commission should require PSE to refund over-collected amounts after 2024 plant additions are trued up to actuals, as PSE's original filing did not have actual costs for all of the 2024 projects.[299] Staff further asserts that the Commission should maintain currently effective rates through 2025 and order PSE to refund trued-up over-collected amounts over the course of 2026 through Schedule 141COL.[300] Staff contends that requiring PSE to file compliance tariff revisions to Schedule 141COL, with an effective date of Jan. 1, 2026 and containing trued-up 2024 plant amounts, would simplify the refund calculation, allow the trued-up amounts to be reflected in the refund, and reduce the number of tariff revisions required by PSE.[301]

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[294] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (stating in part "Major Maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates.").

[295] Brief of PSE at 23 ¶¶ 40-41; Free, Exh. SEF-1T at 14:2 – 15:16.

[296] Free, Exh. SEF-1T at 14:6-17.

[297] Brief of PSE at 23 ¶ 41; Free, Exh. SEF-1T at 15:1-16.

[298] Brief of Staff at 19-20 ¶ 39; McGuire, Exh. CRM-1T at 39:19 – 40:5.

[299] McGuire, Exh. CRM-1T at 29:13-19; 39:3-17.

[300] McGuire, Exh. CRM-1T at 39:19 – 40:8.

[301] McGuire, Exh. CRM-1T at 31:12 – 32:4.

129 Public Counsel maintains that the Commission should require PSE to directly refund any over collected amounts either through a one-time bill credit or over a period not to exceed one year.[302] Public Counsel states that a direct refund is more appropriate than waiting to apply any refund against future decommissioning and remediation expenses because customers benefit more from a direct refund due to the time value of money.[303]

130 NWEC recommends that the Commission require PSE to refund over collected amounts directly to customers rather than apply that refund against PTCs.[304] While AWEC recommends that the Commission disallow various costs PSE included in its filing, it does not provide a recommendation regarding the mechanism for refunding the disallowance.[305]

Commission Determination

131 The Commission requires PSE to directly refund over collected amounts to customers consistent with the method identified by Staff, rather than apply those costs against future PTCs. Staff's proposed method is administratively efficient and will provide more immediate relief to PSE's customers, which is in the public interest and promotes equity. While the Commission appreciates PSE's concern regarding whether a refund complies with CETA's requirement to remove coal power from the allocation of electricity, the Commission does not interpret RCW 19.405.030(1) to prohibit a refund under these circumstances. When the Commission authorized rates to go into effect in this proceeding, it did so subject to refund based on further development of the record and adjudication.[306] As such, the refund required in this case represents an adjustment to rates that were in effect from the end of 2024 to the end of 2025, when the costs and benefits associated with coal power could still be included in rates.

VII. 2025 Colstrip Plant Filing

132 Staff recommends that the Commission clarify the anticipated process for review of PSE's offsetting of 2025 Colstrip plant additions against PTCs. Staff further suggests that the annual Schedule 141COL tariff revision docket filing on or before September 30, 2026, would be a reasonable venue to review PSE's use of PTCs and potentially contesting

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[302] Brief of Public Counsel at 24-25 ¶ 76.

[303] Brief of Public Counsel at 24-25 ¶¶ 74-76; Dreyer, Exh. JMD-1CTr at 8:15 – 9:3.

[304] Cebulko, Exh. BTC-1CT at 3:12-13.

[305] Brief of AWEC at 10 ¶ 20.

[306] *WUTC v. Puget Sound Energy*, Docket UE-240729, Order 01 at 3 ¶ 9 (Dec. 23, 2024).

certain plant additions.[307] AWEC similarly argues that the Commission should require PSE to submit a filing regarding the Company's final regulatory accounting for Colstrip as of December 31, 2025, that will involve a prudence determination for plant balances that the Company proposes to offset with PTCs.[308] AWEC also asks that the Commission clarify that the same principles that apply to the Commission's review in this case will apply to the Commission's review of PSE's 2025 Colstrip plant additions.[309] Public Counsel also indicates that it supports AWEC's recommendation that the Commission evaluate the prudency of the Company's 2025 Colstrip plant additions to be applied against PTCs.[310] PSE states that it agrees with Staff's proposal regarding the treatment of 2025 plant requirements in PSE's annual Schedule 141COL filings.[311]

Commission Determination

133 The Commission agrees that it is appropriate to provide further guidance regarding the review of 2025 Colstrip plant additions and agrees with Staff's recommended process. The Commission requires PSE to file as part of its annual Schedule 141COL filing on or before September 30, 2026, its final proposed regulatory accounting for Colstrip costs as of December 31, 2025. As part of this filing, all interested parties and the Commission will have an opportunity to review whether such costs should be offset by PTCs. While the Commission does not prejudge any issues that may arise in the context of reviewing PSE's 2025 Colstrip investments, this Order should be understood as guidance with respect to the Commission's review in that proceeding.

FINDINGS OF FACT

134 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

135 (1) The Commission is an agency of the state of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers

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307 McGuire, Exh. CRM-1T at 34:13 – 36:7.

308 Brief of AWEC at 9 ¶ 19; Mullins, Exh. BGM-1T at 12:11-20.

309 Brief of AWEC at 10 ¶ 20.

310 Brief of Public Counsel at 25-26 ¶ 78; Dreyer, Exh. JMD-2CT at 7:2-8.

311 Free, Exh. SEF-1T at 16:2-5.

of property and affiliated interests of public service companies, including electric and companies.

136 (2) PSE is a "public service company," and an "electrical company," as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. PSE provides electric utility service to customers in Washington.

137 (3) On September 30, 2024, PSE filed with the Commission a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL.

138 (4) PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800kWh per month would be a rate increase of $.18 or 0.16 percent.

139 (5) On December 19, 2024, the Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates are subject to refund. The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

140 (6) On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

141 (7) Colstrip Units 3 and 4 are coal-fired generating units.

142 (8) At 12:00 a.m. on January 1, 2026, Pacific Standard Time, PSE's ownership interest will transfer to NorthWestern and costs associated with coal-fired generation of electricity will be removed from rates for electricity for PSE's Washington State customers.

143 (9) As of January 1, 2026, Colstrip will provide no benefit to Washington electric retail customers.

144 (10) As of January 1, 2026, Colstrip will not be necessary or useful in PSE's provision of electric service to Washington customers.

145 (11) Six Colstrip projects related to human health and safety provide near-term, immediate benefits that exceed the cost of investment. Those six projects are: (1)

Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

146 (12) PSE has not demonstrated that its remaining investments in Colstrip, other than the six human health and safety projects previously identified, provide any benefits to Washington customers after December 31, 2025.

147 (13) The record developed in this proceeding does not indicate when the U4 Generator Exciter and the Northern Chyanne AAQ System were placed into service.

148 (14) PSE has not demonstrated a need for four projects that lack capital justification. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

149 (15) PSE's costs for capital improvements to the SmartBurn TOFA component of Colstrip Units 3 and 4 were not prudently incurred because the Company was aware at the time it made the decision to replace the TOFA components, that the Commission had previously found PSE's investment in the TOFA component for Colstrip Units 3 and 4 imprudent. Because PSE's investment in the TOFA components in this docket were not prudently incurred, recovery of costs associated with TOFA components are disallowed.

150 (16) The Boiler Burner, CRO, and SOFA are not SmartBurn components that were previously disallowed in PSE's 2019 GRC.

151 (17) The NPV analysis provided by PSE demonstrates a reasonable need for PSE's Colstrip investments, other than the four projects lacking capital justification and the SmartBurn TOFA component, up to December 31, 2025, after which the assets cannot provide any benefit to Washington customers.

152 (18) For its remaining Colstrip investments and costs, PSE has provided sufficient evidence demonstrating that it considered alternatives to its Colstrip investments and costs, consulted with its management, and contemporaneously documented its analysis.

153 (19) PSE's annual amortization of the 2024 Colstrip Unit 4 outage is $1,603,174, rather than $1,609,006, based on its updated actual costs associated with the outage.

154 (20) PSE's annual amortization cost associated with the 2024 Colstrip Unit 4 outage should be adjusted to $1,603,174.

155 (21) Based on the analysis in this proceeding, PSE has over-collected $6,843,705 that should be refunded to its customers, subject to the true up required by this Order. The computation of the over-collected amounts is attached to this Order as Appendix A (Confidential).[312]

156 (22) Staff's recommended process for implementing a refund of over-collected amounts, as described in Exh. CRM-1T at 39:1 – 40:8 is reasonable and not contrary to CETA.

157 (23) Staff's recommended process for reviewing PSE's 2025 Colstrip investments is reasonable.

CONCLUSIONS OF LAW

158 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

159 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

160 (2) PSE is an electric company and a public service company subject to Commission jurisdiction.

161 (3) PSE bears the burden to demonstrate that its provisional rates subject to refund are fair, just, reasonable, and sufficient. The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

162 (4) PSE has not demonstrated that the rates allowed to go into effect January 1, 2025, subject to refund, are fair, just, reasonable, and sufficient.

163 (5) Colstrip Units 3 and 4 are coal-fired resources as that term is defined in RCW 19.405.020(7)(a).

[312] Appendix A (Confidential) shall be provided to PSE and parties that have signed the protective order agreement and shall be posted to the docket.

164 (6) After a careful analysis of the canons of Legislative intent, we find that the Legislature intended for a broad definition of the terms "retired" and "retirement" in RCW 19.405.030(3), which includes the accounting definition.

165 (7) We adopt the Generally Accepted Accounting Principles and Washington State Auditor's definitions of the terms "retired" and "retirement" in the application of RCW 19.405.030(3) in this docket.

166 (8) The provisions of CETA apply to the proceedings in this docket because we find that the Company will have retired Colstrip Units 3 and 4 pursuant to RCW 19.405.030(3) by 12:00 a.m. January 1, 2026.

167 (9) The A&A Agreement between PSE and NorthWestern is not subject to Commission approval under RCW 80.12.020 because, pursuant to RCW 19.405.030(1)(a)'s requirement that coal-fired resources be removed from PSE's allocation of electricity on or before December 31, 2025, Colstrip Units 3 and 4 cannot provide any benefit to PSE's Washington customers.

168 (10) The Commission should reject the request to have PSE file the A&A Agreement for Commission approval pursuant to RCW 80.12.020.

169 (11) The Commission should require PSE, as a condition of this order, to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

170 (12) The six human health and safety investments in Colstrip are fully used and useful. The six projects are: (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

171 (13) PSE has not demonstrated that its remaining capital investments in Colstrip are used and useful for service in Washington after December 31, 2025.

172 (14) The Commission should disallow a prorated portion of the Colstrip capital investments based on the portion of the investment's useful lives in service prior to December 31, 2025.

173 (15) PSE should be required to file an update to this docket detailing when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into

service, including supporting documentation. If either asset was placed into service prior to December 31, 2025, PSE should be allowed to recovery a prorated portion of the costs associated with those investments, consistent with the proration methodology described in paragraph 95.

174 (16) PSE has not demonstrated that its investments in four projects that lack capital justification were prudent. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

175 (17) The TOFA component of the NOx control system is a SmartBurn component that was previously disallowed in PSE's 2019 GRC and therefore is imprudent.

176 (18) PSE's remaining investments and costs related to Colstrip that are not disallowed as not used and useful are prudent.

177 (19) PSE should be required to refund over-collected revenue through Schedule 141COL starting Jan. 1, 2026, consistent with Staff's recommended process as described in Exh. CRM-1T at 39:1 – 40:8.

178 (20) PSE should be required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

ORDER

THE COMMISSION ORDERS:

179 (1) Puget Sound Energy's tariff revisions filed on September 30, 2024, further revised on December 20, 2024, and allowed to go provisionally into effect on January 1, 2025, by prior Commission order, are rejected and subject to refund with respect to the over-collected amounts.

180 (2) Puget Sound Energy is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order. PSE should file its compliance tariffs with an effective date of January 1, 2026, on or before December 24, 2025.

181 (3) As a condition of this order, Puget Sound Energy is required to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

182 (4) As a condition of compliance with this order, Puget Sound Energy is required to submit an update to this docket indicating when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into service, with supporting documentation, and the record should be reopened for the limited purpose of incorporating this information. If the assets were placed into service prior to December 31, 2025, Puget Sound Energy is authorized to recover a prorated portion of the value of those assets, consistent with the methodology described in paragraph 95.

183 (5) Puget Sound Energy is required to refund over-collection amounts consistent with the methodology described by Staff in Exh. CRM-1T at 39:1 – 40:8.

184 (6) Puget Sound Energy is required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

185 (7) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

186 (8) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Lacey, Washington, and effective December 19, 2025.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

BRIAN J. RYBARIK, Chair

ANN E. RENDAHL, Commissioner

MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-58:
EPA CEMS Data 2021-2025

State	Facility Na	Facility ID	Year	Gross Load	Steam Loa	SO2 Mass (	CO2 Mass	NOx Mass (	Heat Input
WA	Centralia	3845	2021	3338498		794.285	3808194	3237.726	36310042
WA	Centralia	3845	2022	3800396		1261.793	4321275	3650.313	41199918
WA	Centralia	3845	2023	4436385		1161.237	4960494	4107.822	47296887
WA	Centralia	3845	2024	3039265		934.718	3510596	2804.53	33472505
WA	Centralia	3845	2025	2449289		683.202	2279285	1981.104	21732302

(mmBtu)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-59:
NERC 2025-26 Winter Assessment

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025

Table of Contents

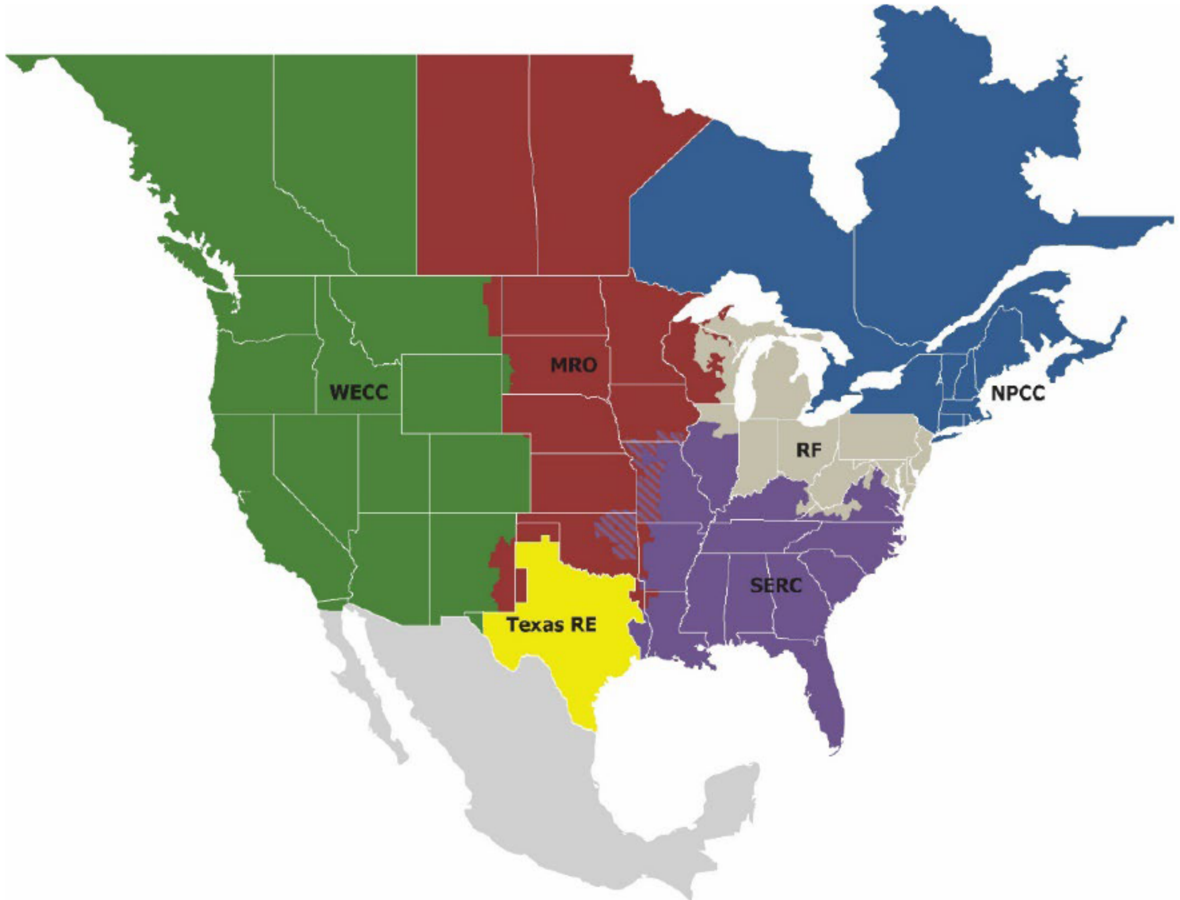
Preface

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 made up of six Regional Entities as shown in the map and 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	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA 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 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 the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):
   - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
   - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
   - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
   - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
   - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* 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.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

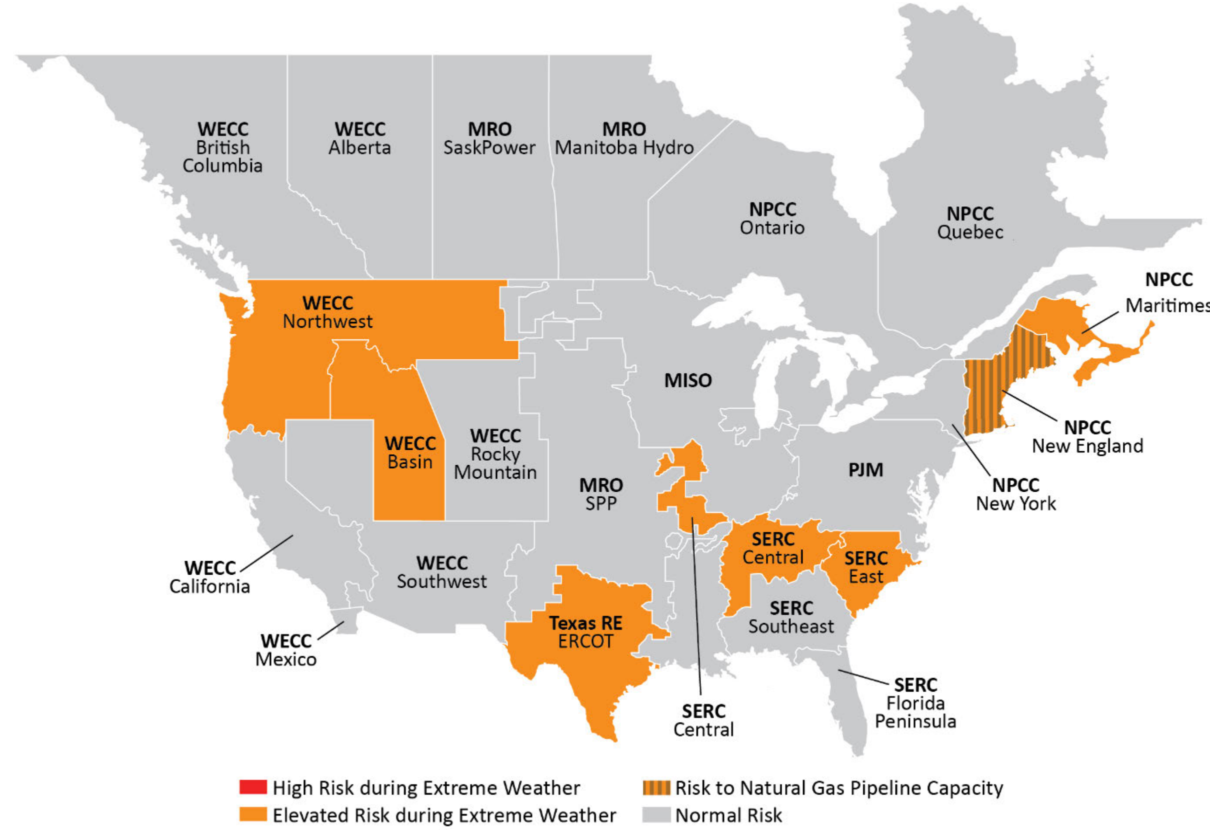


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in Figure 2 below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

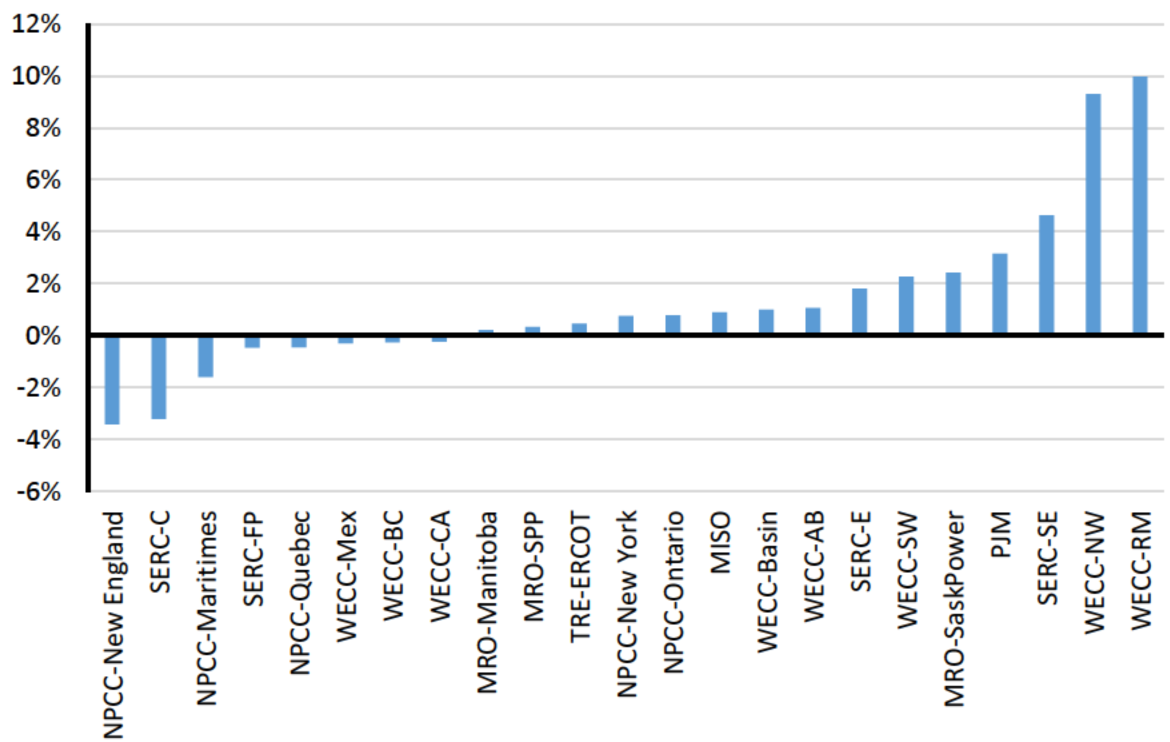


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See Data Concepts and Assumptions section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. Table 1 shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see Variable Energy Resource Contributions section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the Demand and Resource Tables.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

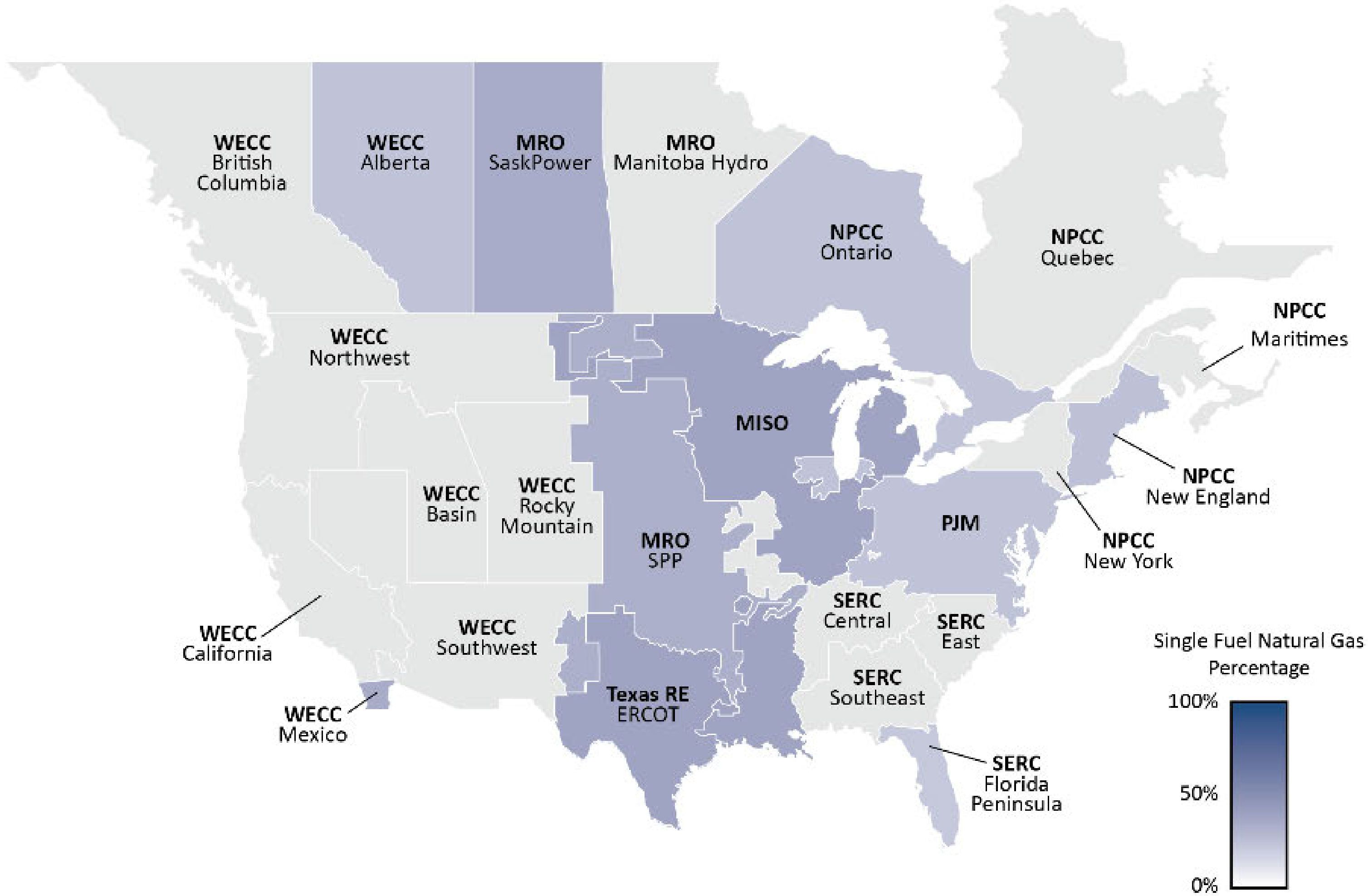
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Note: Areas with less than 20% natural gas are shown in light gray.

Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

Risk Assessment Discussion

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

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

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 winter 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 3, each assessment area's ARMs 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.

Areas highlighted in orange in Figure 1 above have been identified as having resource adequacy or energy risks for the winter and are included in the Key Findings section's discussion that follows. 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 ARM, 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 winter season. Results are summarized in Table 5. 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 loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see Table 4 for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	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 operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	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 operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

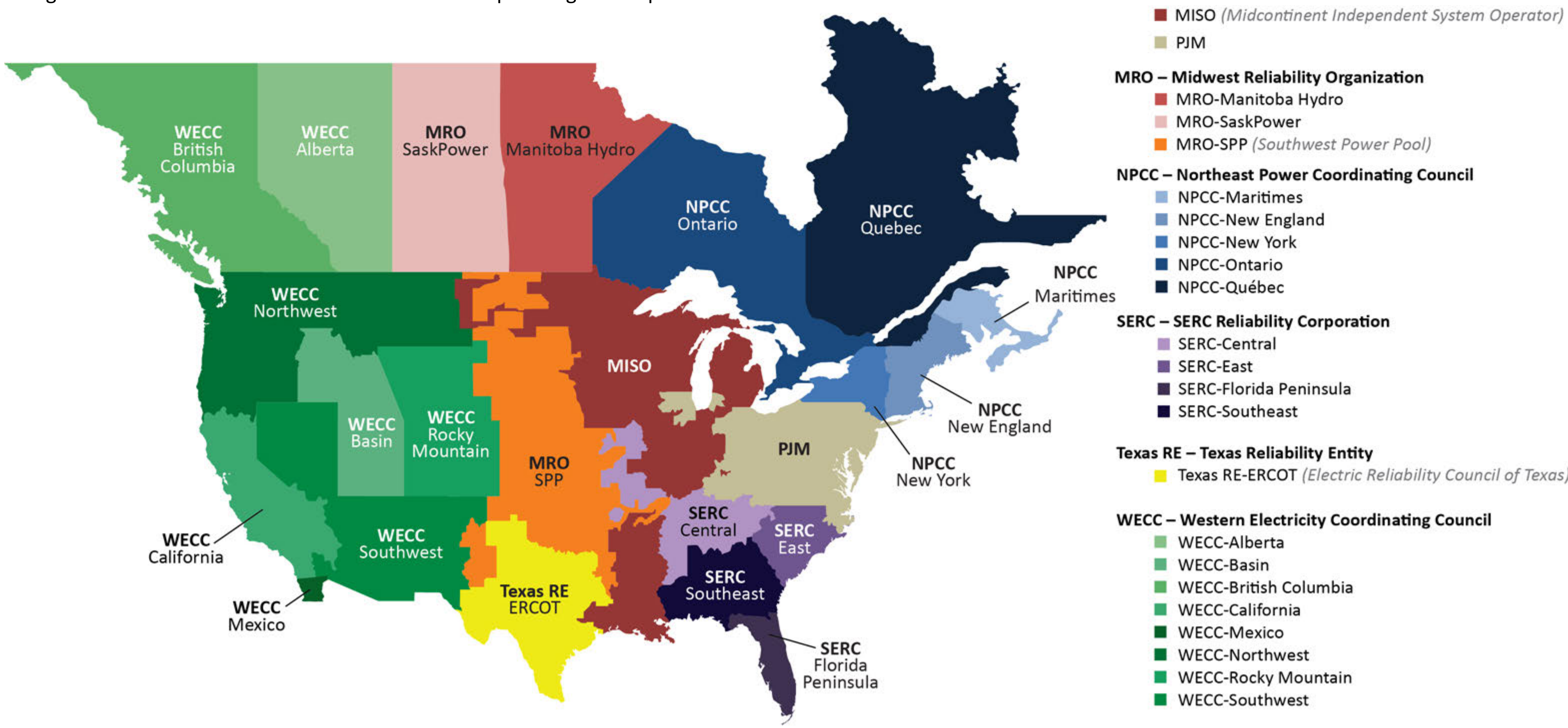
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

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 ARM compared to a reference margin level (RML) that is established for each area 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 two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter 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 WRA 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 vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.

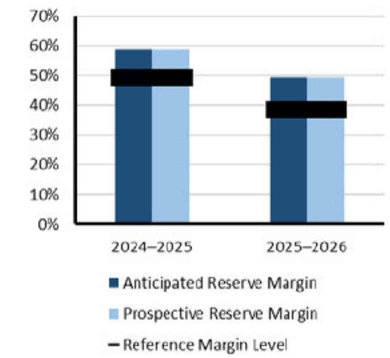


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

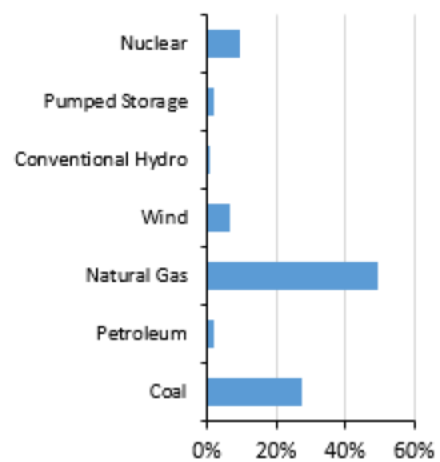
On-Peak Reserve Margin[10]



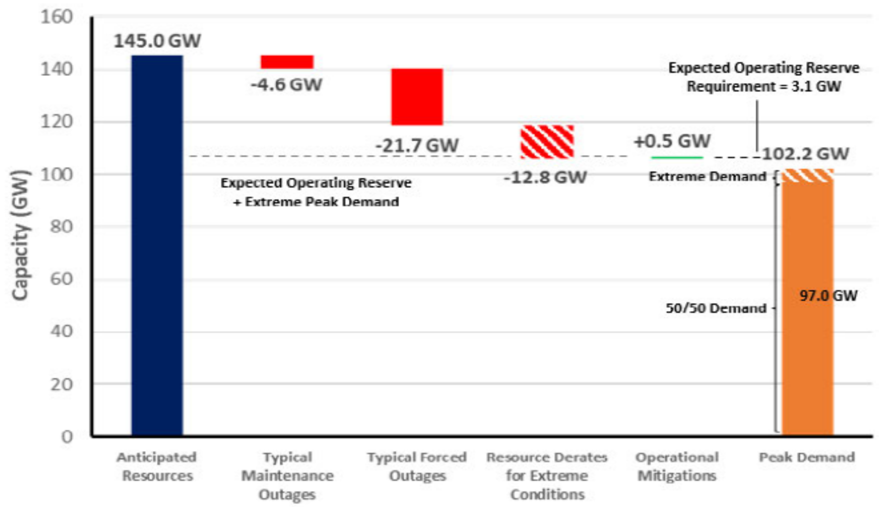
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter 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 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.

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 Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

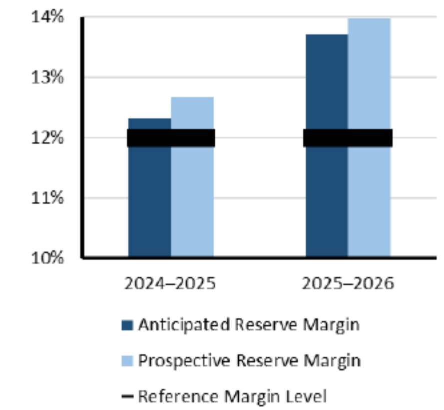
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

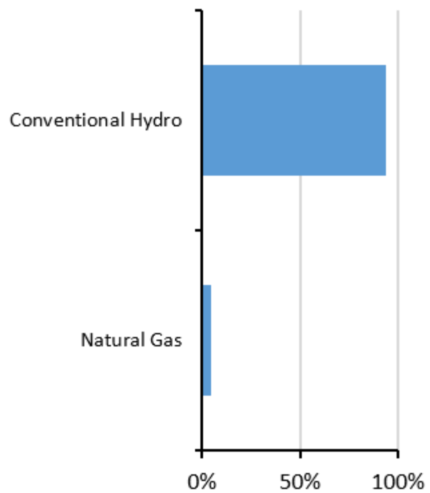
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

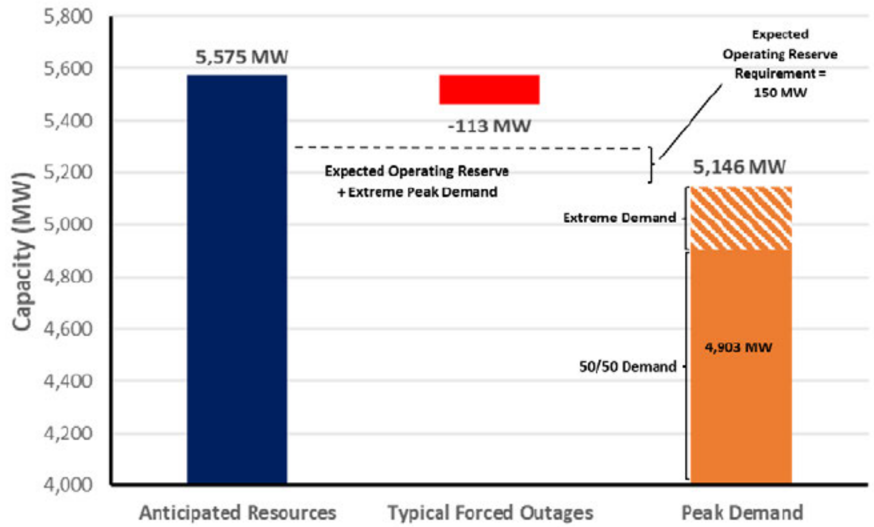
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 weather data

Typical Forced Outages: Accounts for average forced outages

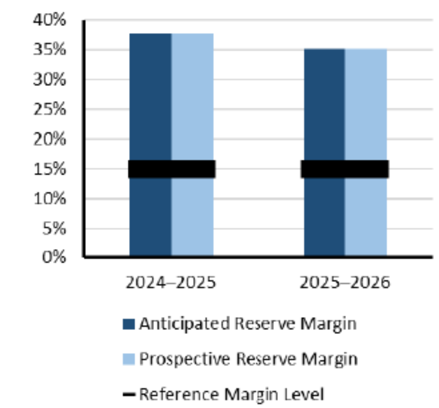
MRO-SaskPower

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 Bulk Electric System (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

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, 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 the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

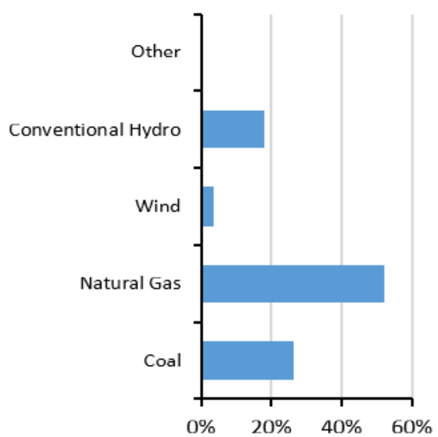
On-Peak Reserve Margin



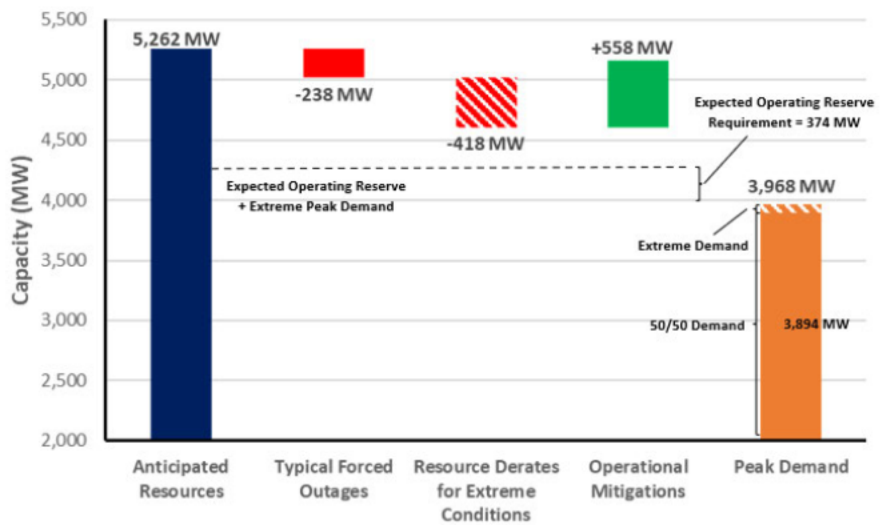
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification

MRO-SPP

SPP'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.

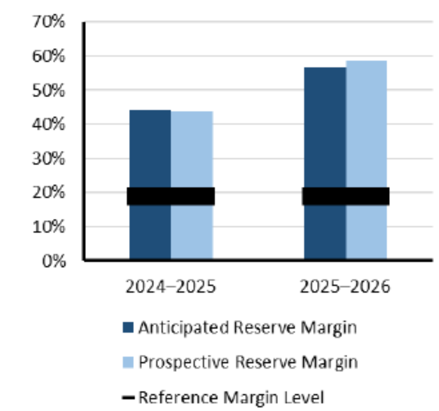
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

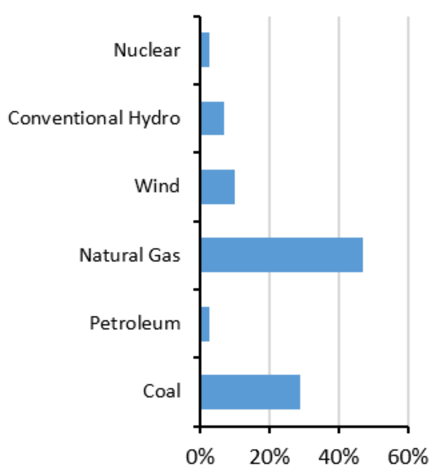
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

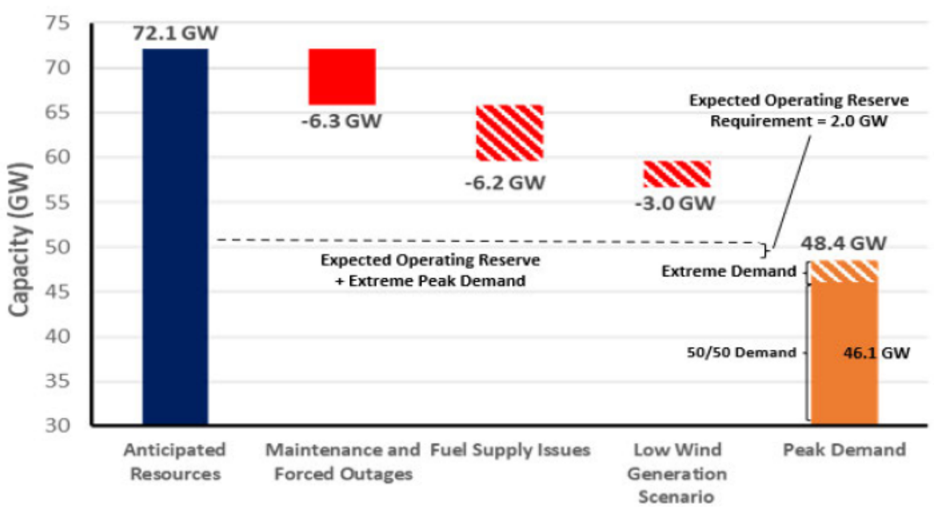
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

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 balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority 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.

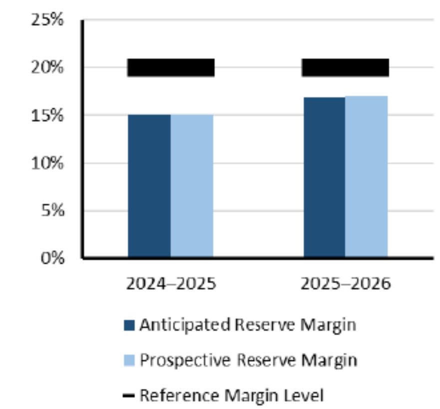
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

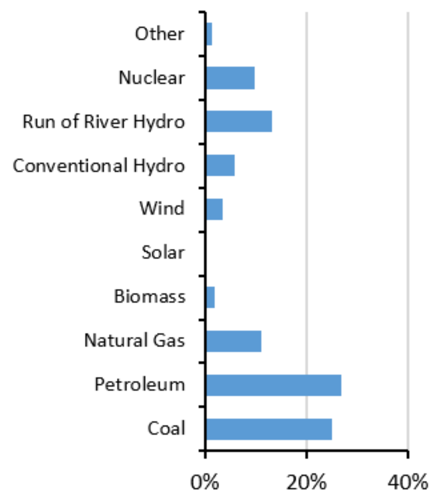
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

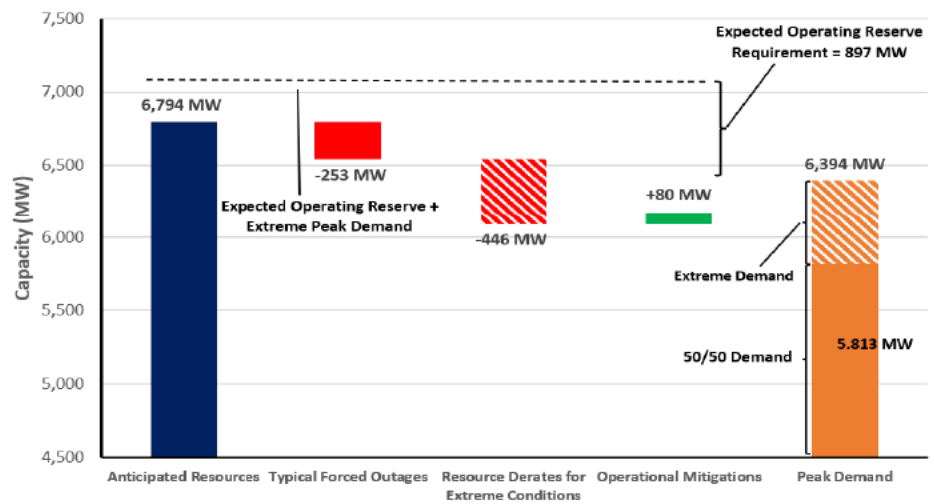
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching

NPCC-New England

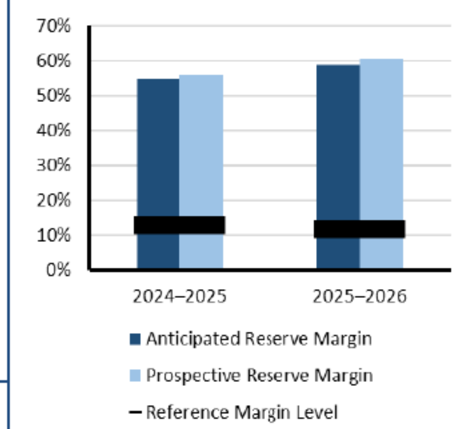
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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 expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

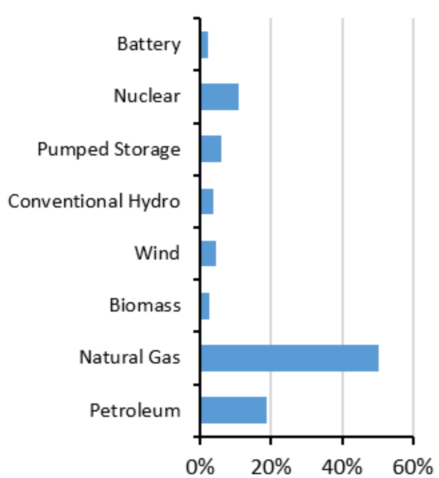
On-Peak Reserve Margin



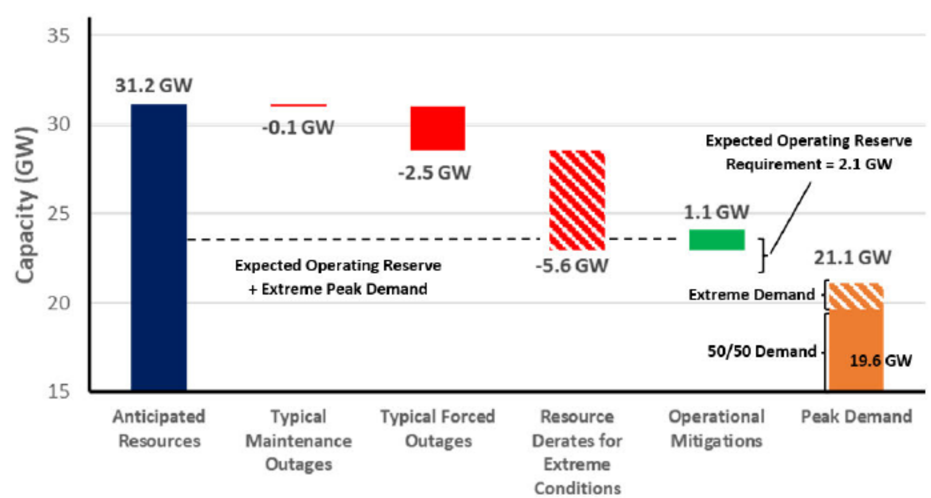
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter 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 capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

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 WRA, the established RML 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%.

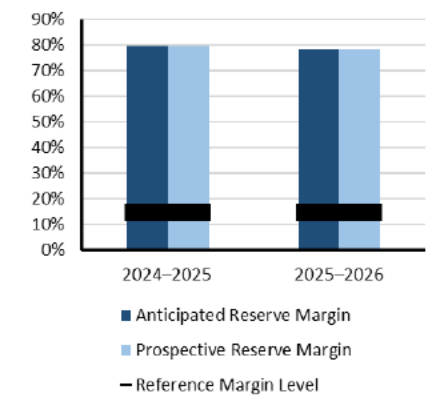
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

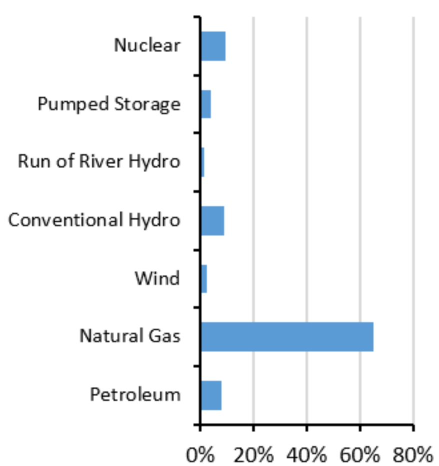
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

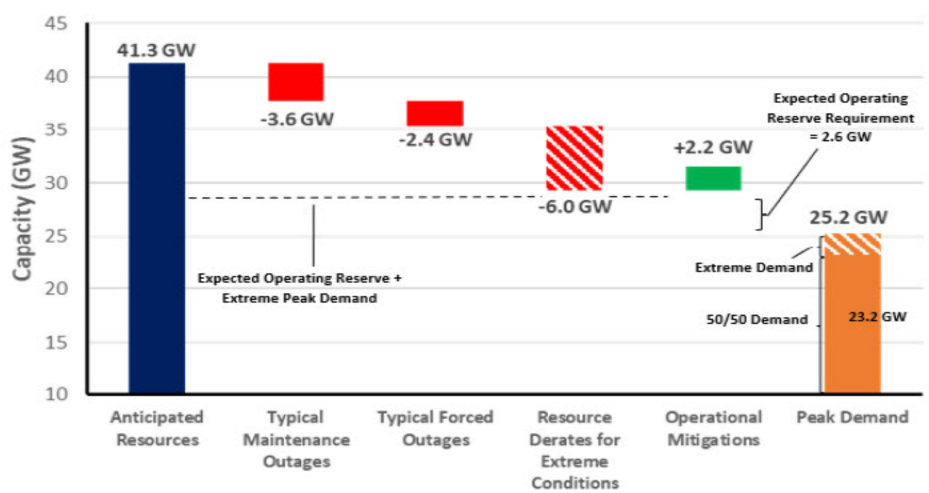
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures

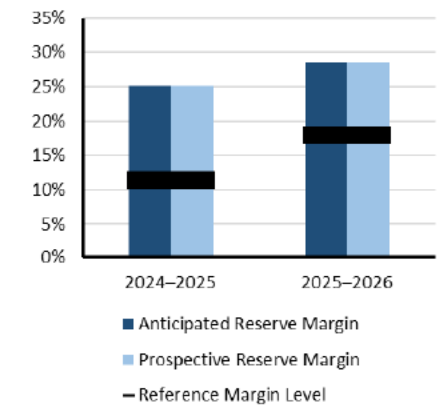
NPCC-Ontario

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 almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority 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

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

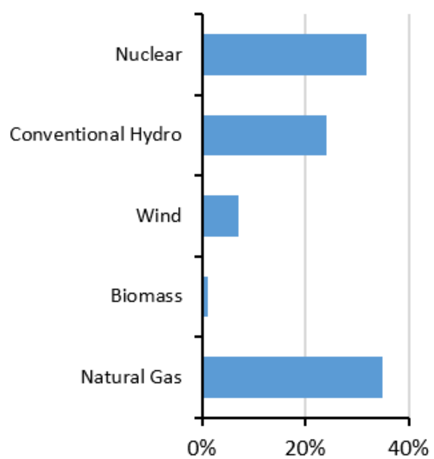
On-Peak Reserve Margin



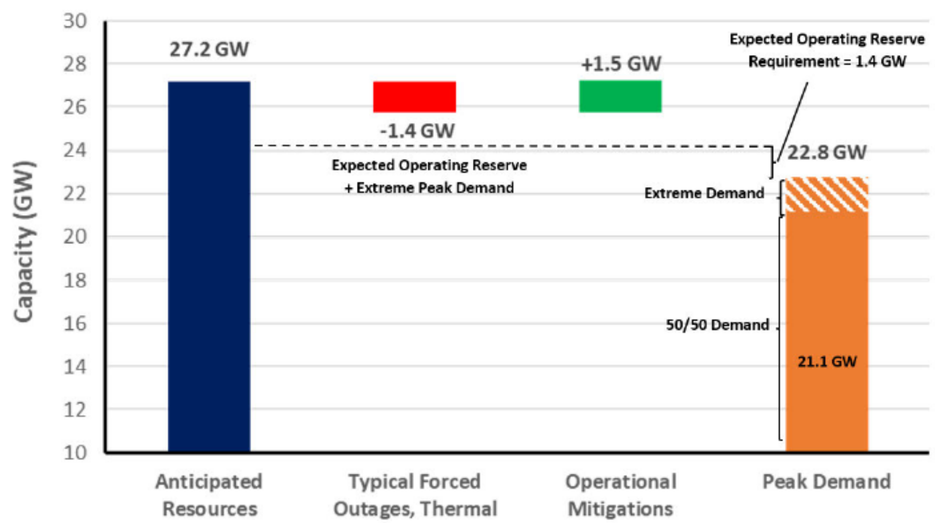
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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 from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies

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 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 predominately 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.

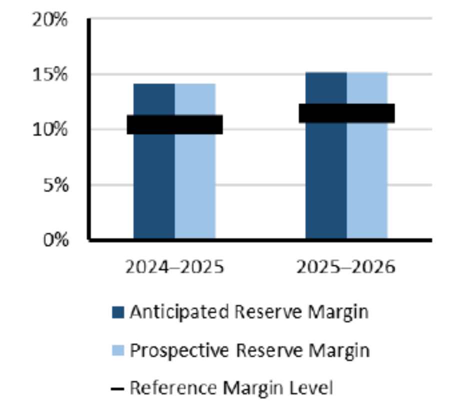
Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

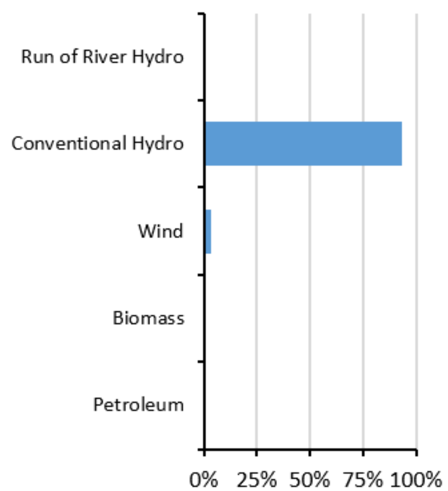
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

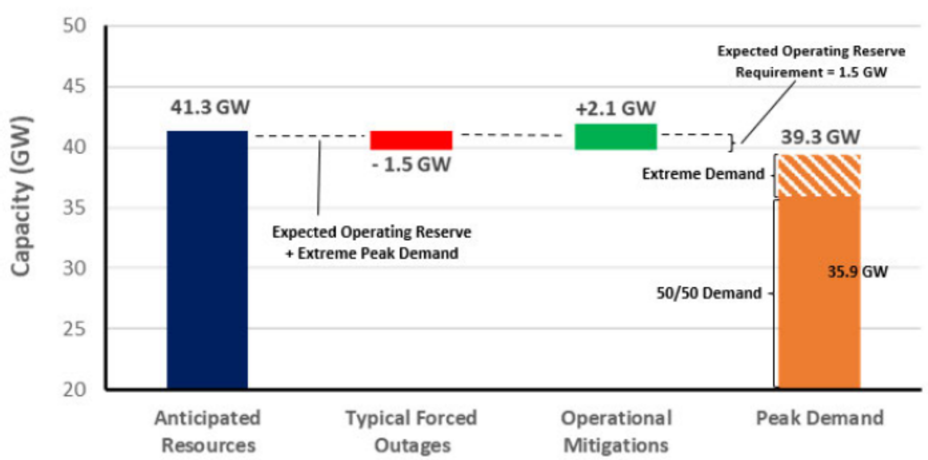
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves

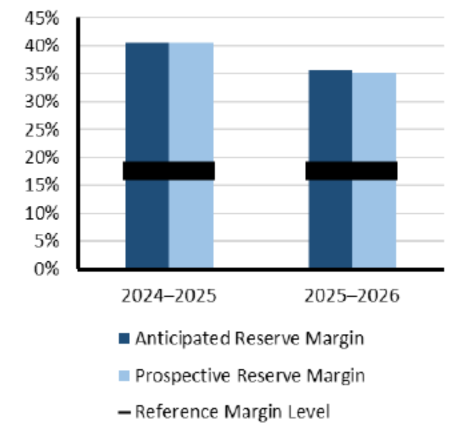
PJM

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 with an approximate population of 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

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

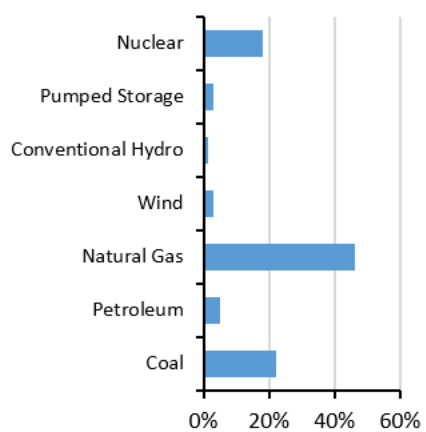
On-Peak Reserve Margin



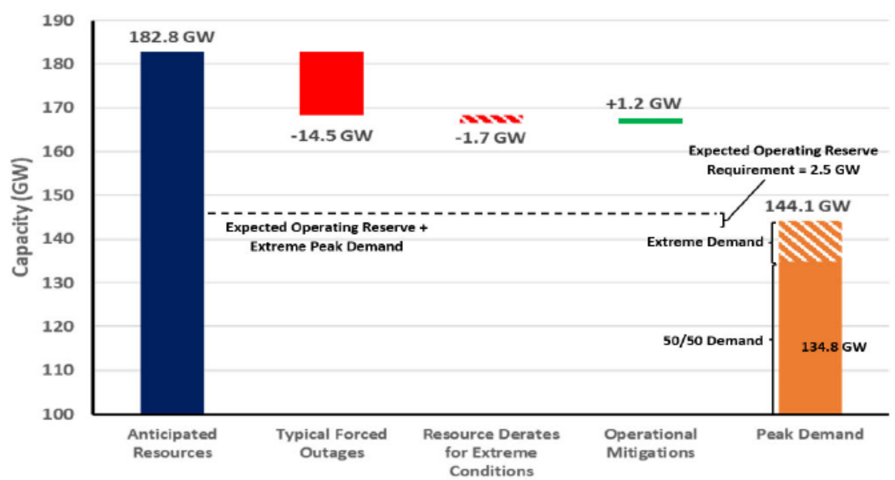
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value 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 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.

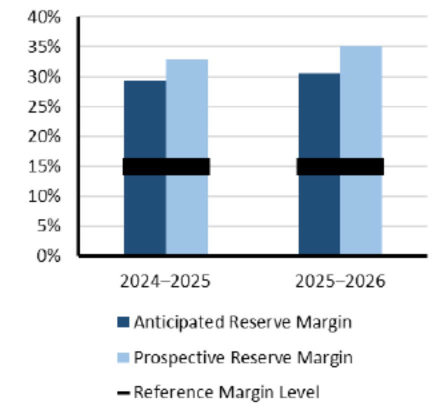
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

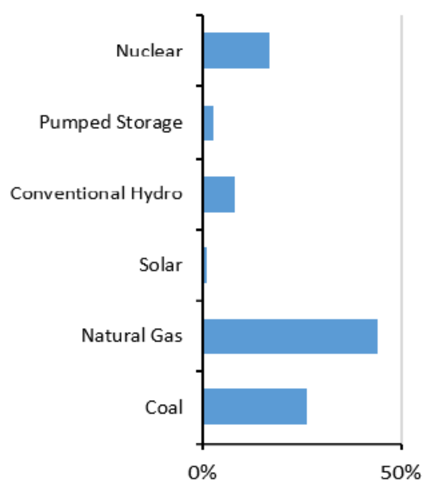
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

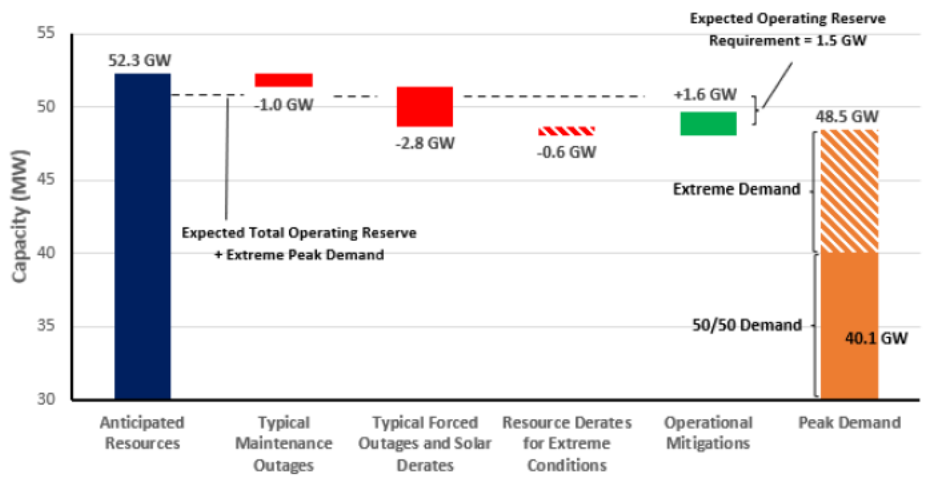
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures

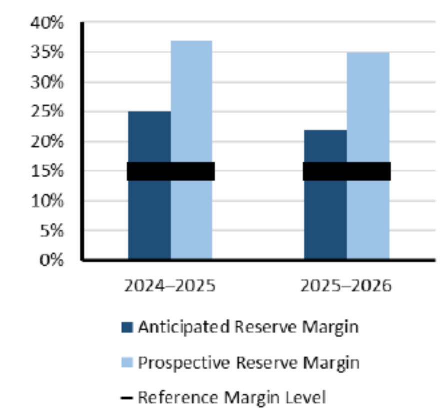
SERC-East

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 Regional Entities 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

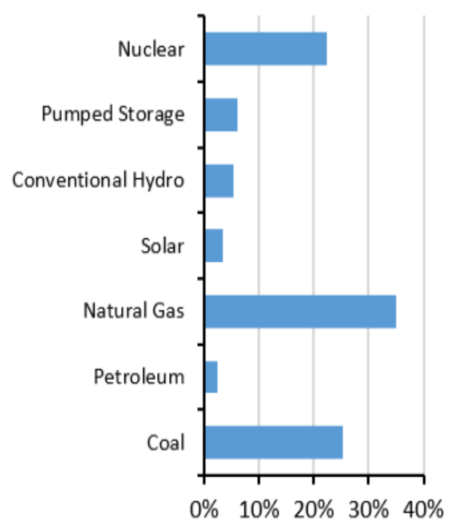
On-Peak Reserve Margin



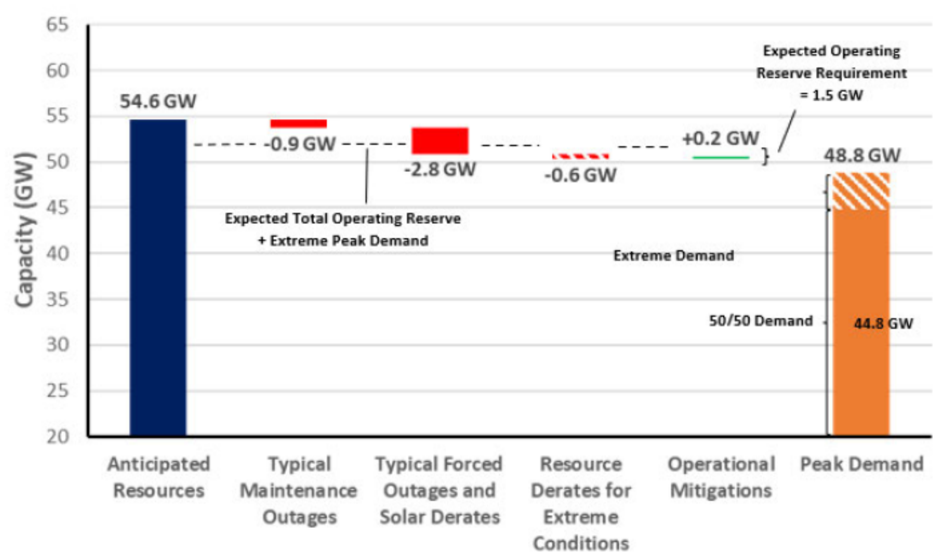
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW 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 Regional Entities across North America that is 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 United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

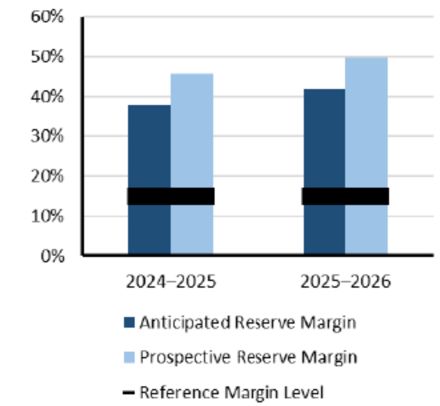
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

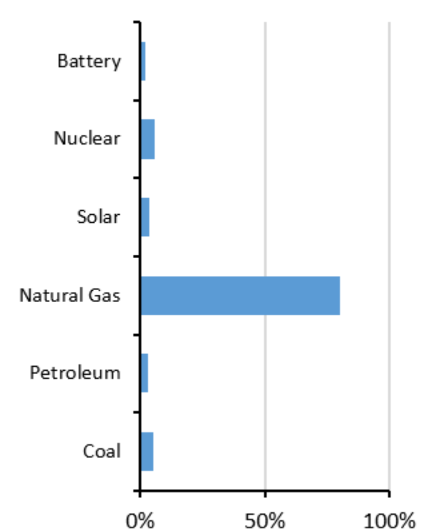
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

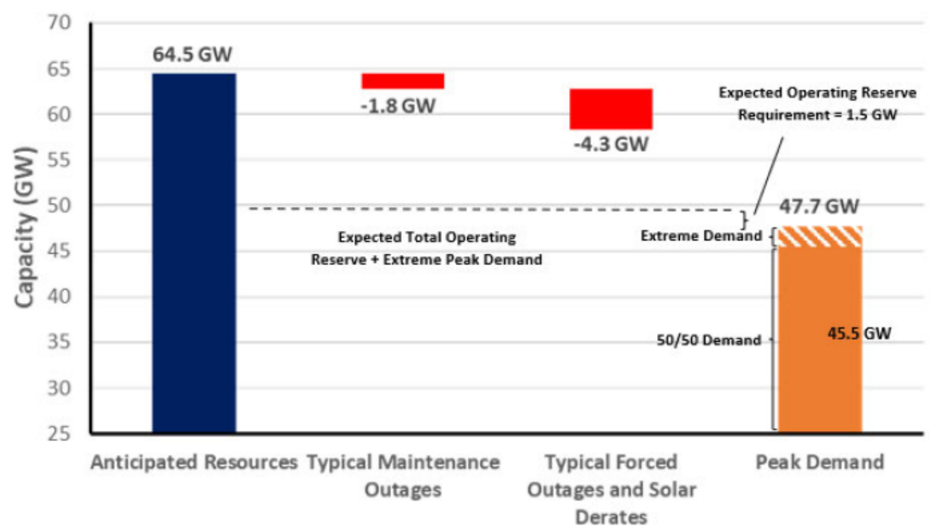
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood 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 Regional Entities across North America that is 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

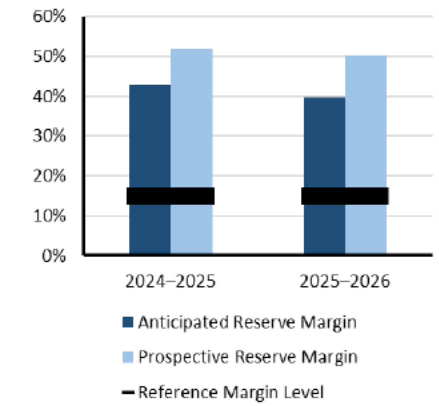
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

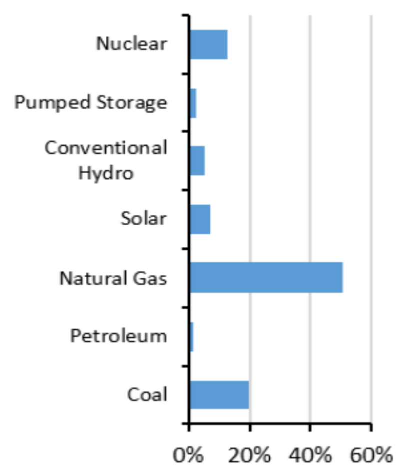
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

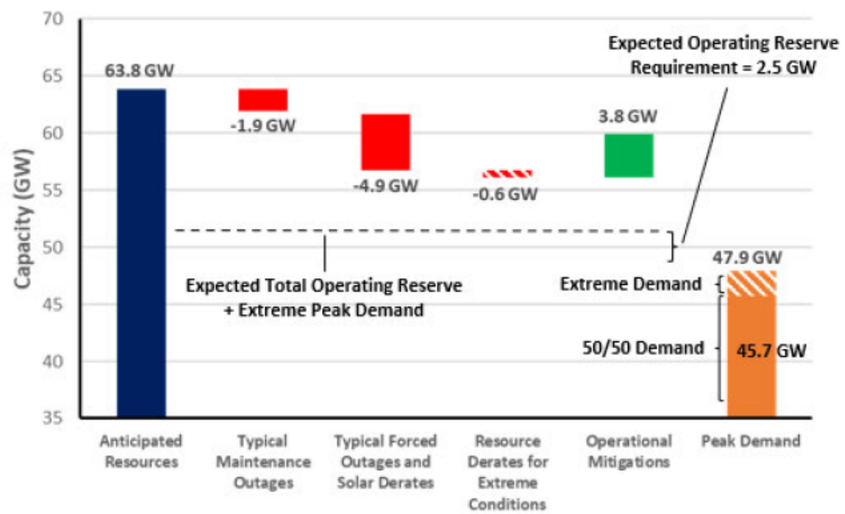
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures

Texas RE-ERCOT

ERCOT is the 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 covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 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 power grid.

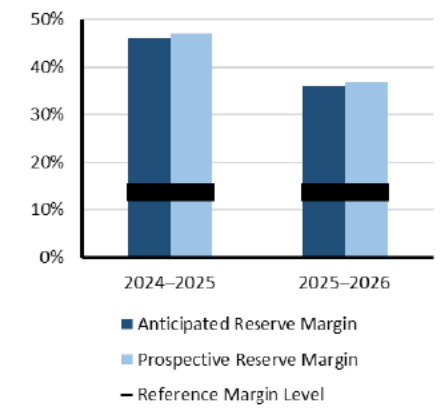
Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

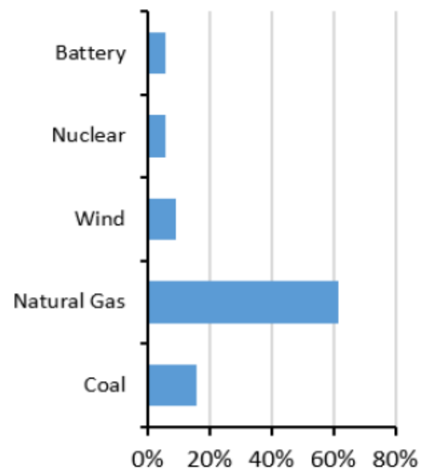
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

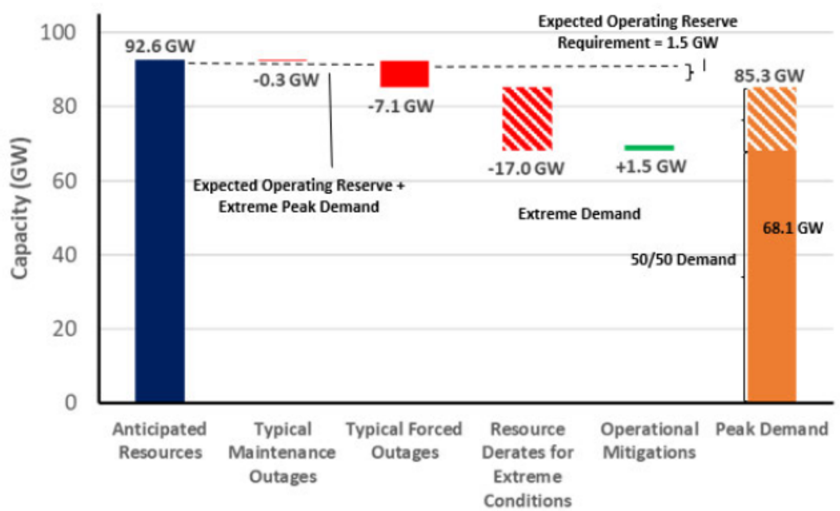
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports

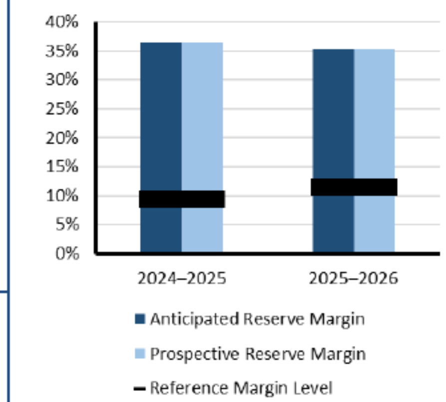
WECC-Alberta

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

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

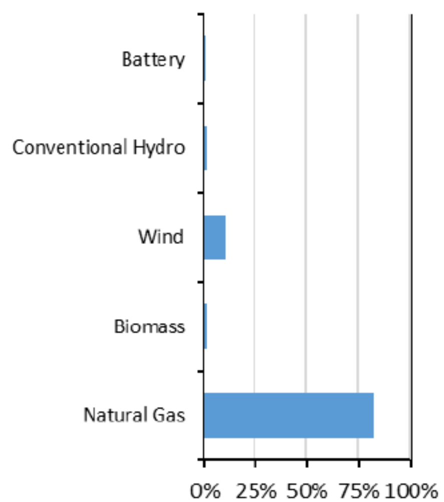
On-Peak Reserve Margin



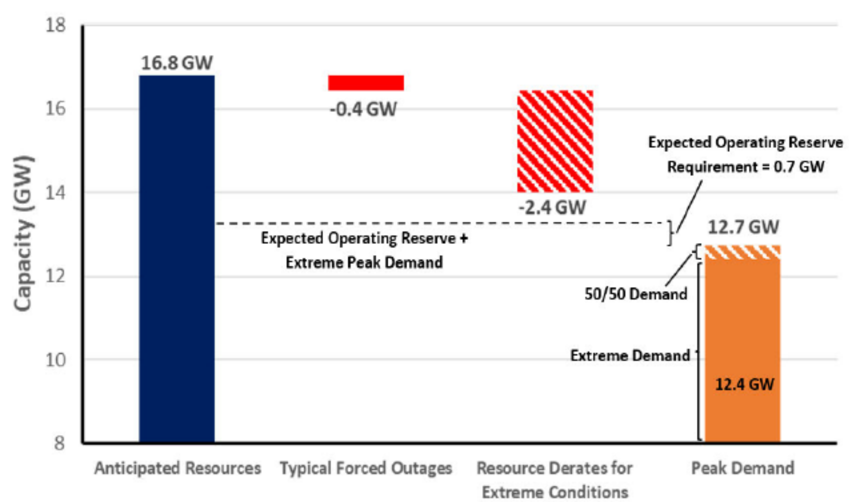
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 BA 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 2025-26 WRA 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 2024–25 WRA.*

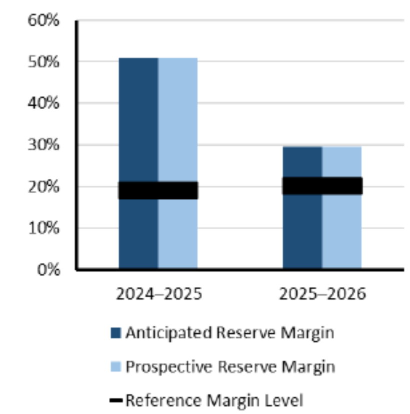
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

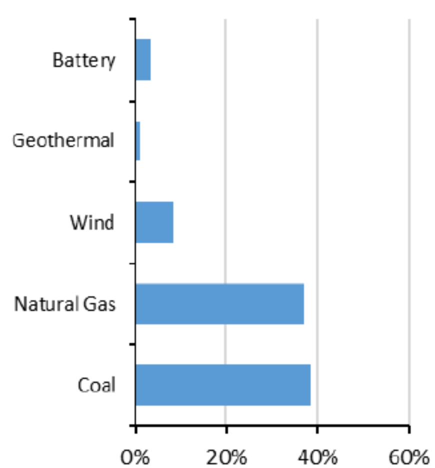
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

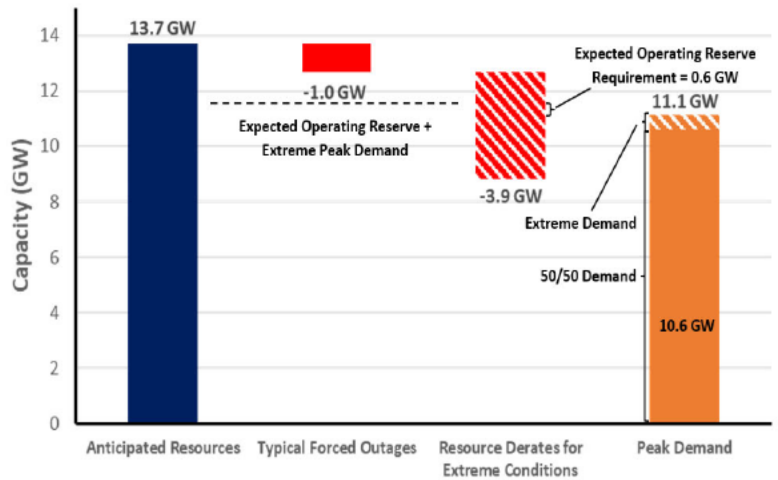
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 30 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 winter.

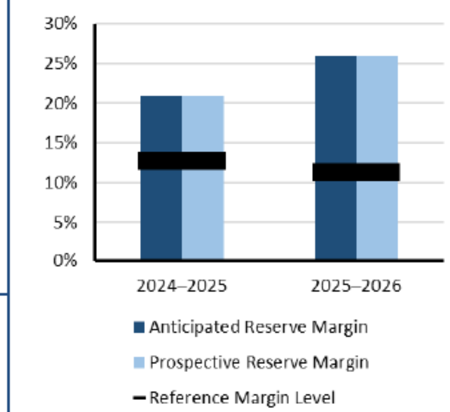
Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

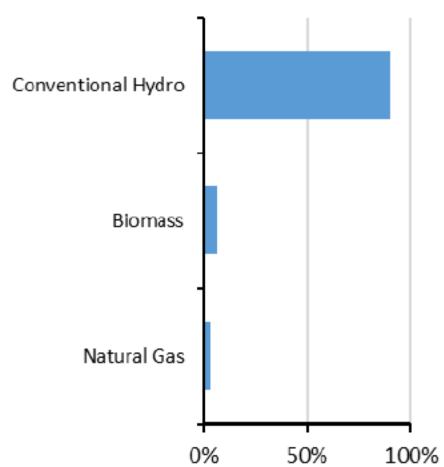
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

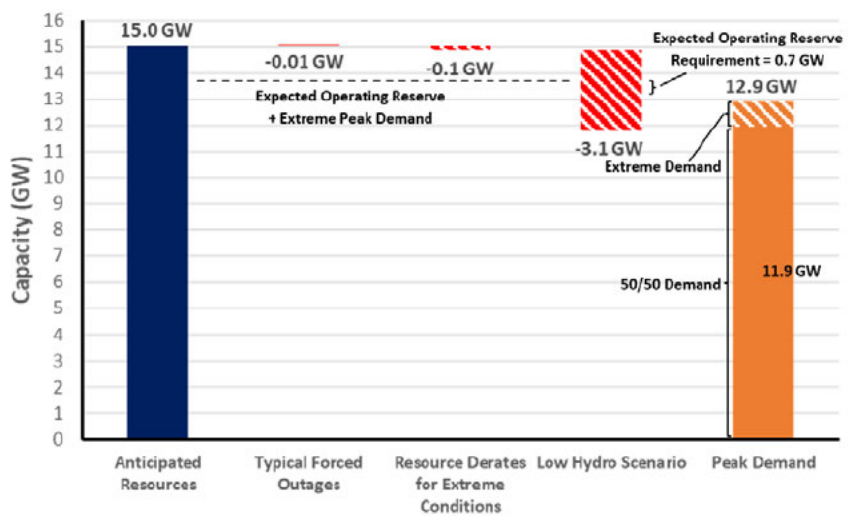
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output

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. *Note: The 2025–26 WRA 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 2024–25 WRA.*

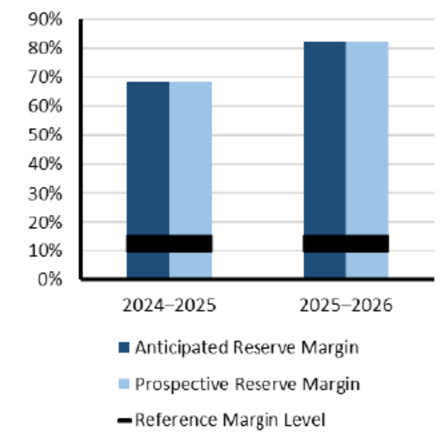
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

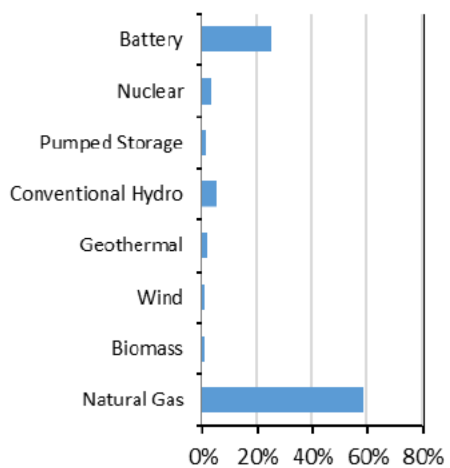
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

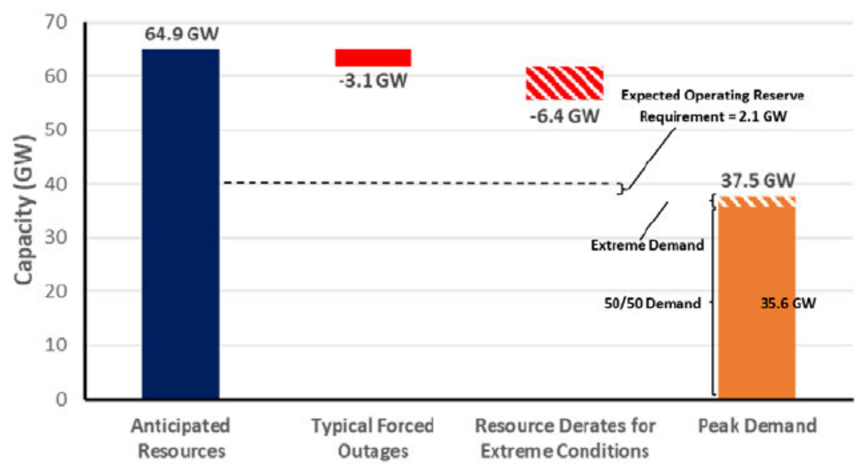
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA 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 2024–25 WRA.*

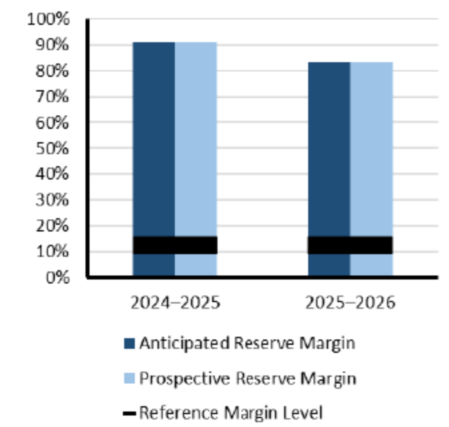
Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

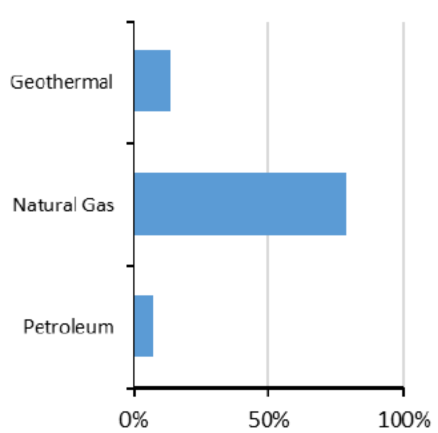
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

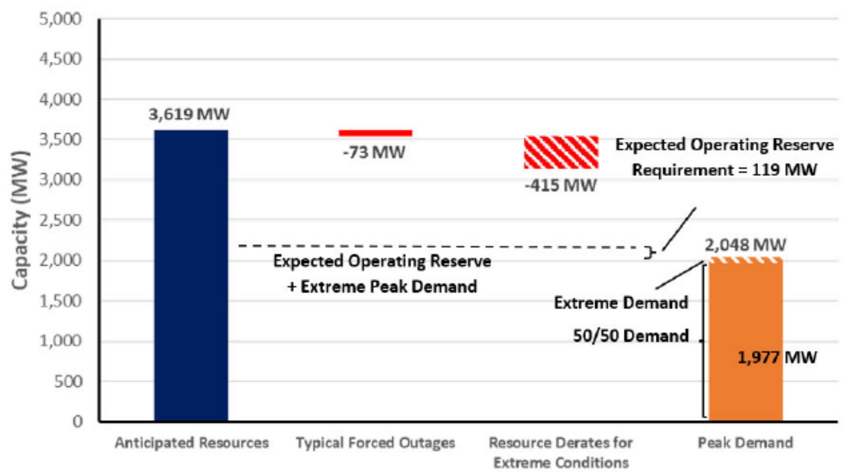
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 2025–26 WRA 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 2024–25 WRA.*

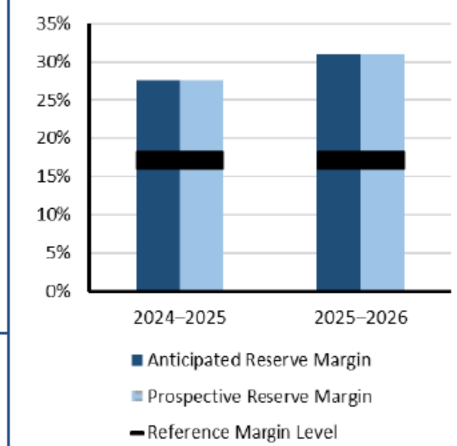
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

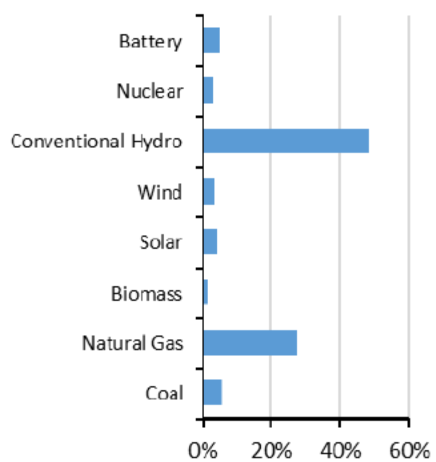
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

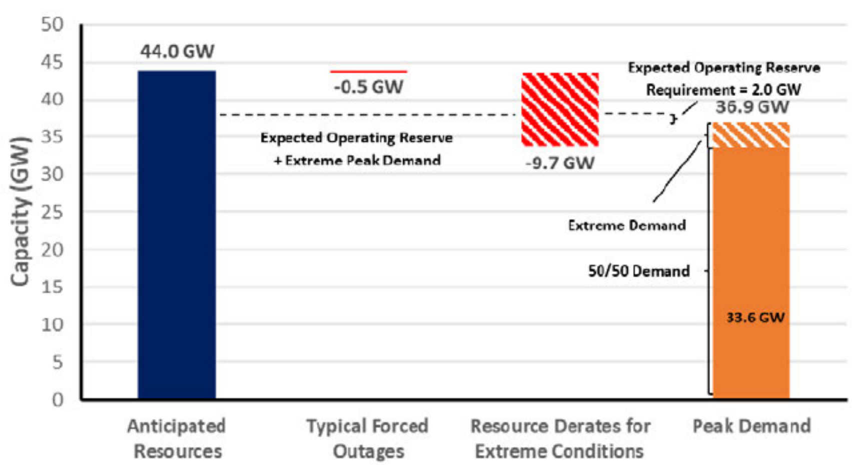
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA 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 2024–25 WRA.*

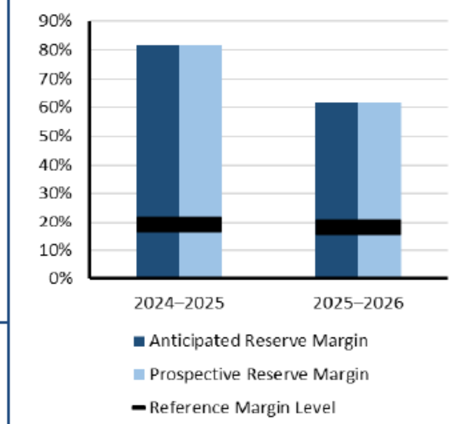
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

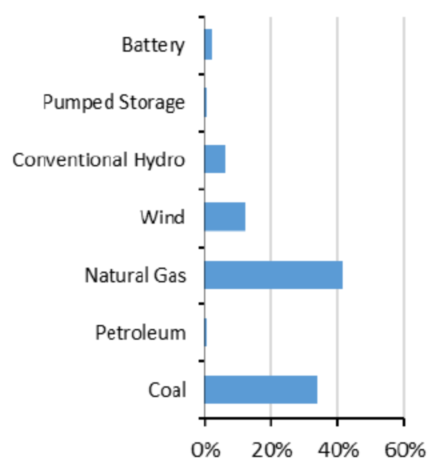
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

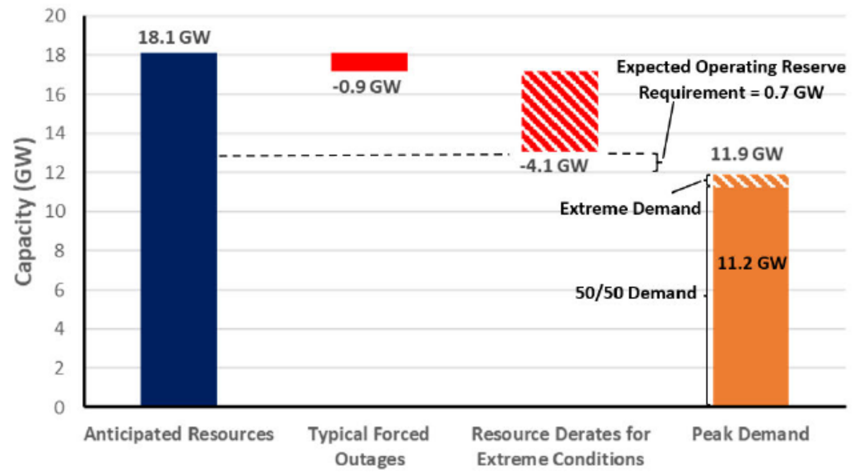
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 2025–26 WRA 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 2024–25 WRA.*

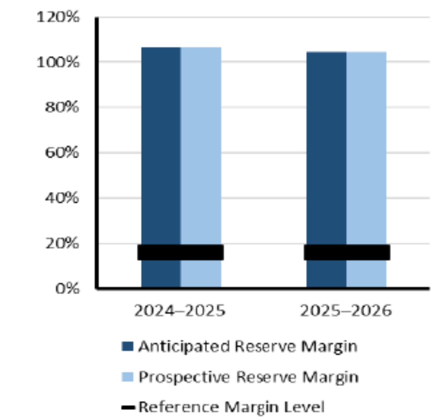
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

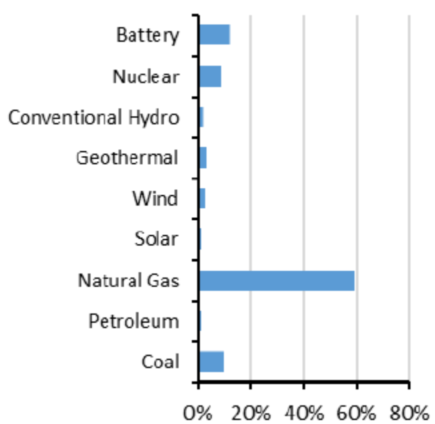
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

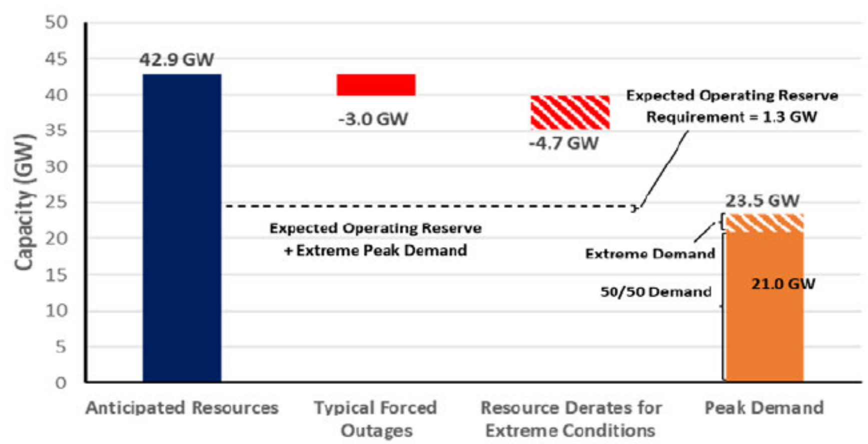
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

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

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] 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 variable energy resources (VER) (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.

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

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

[13] 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.

[14] 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 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.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in Figure 4.

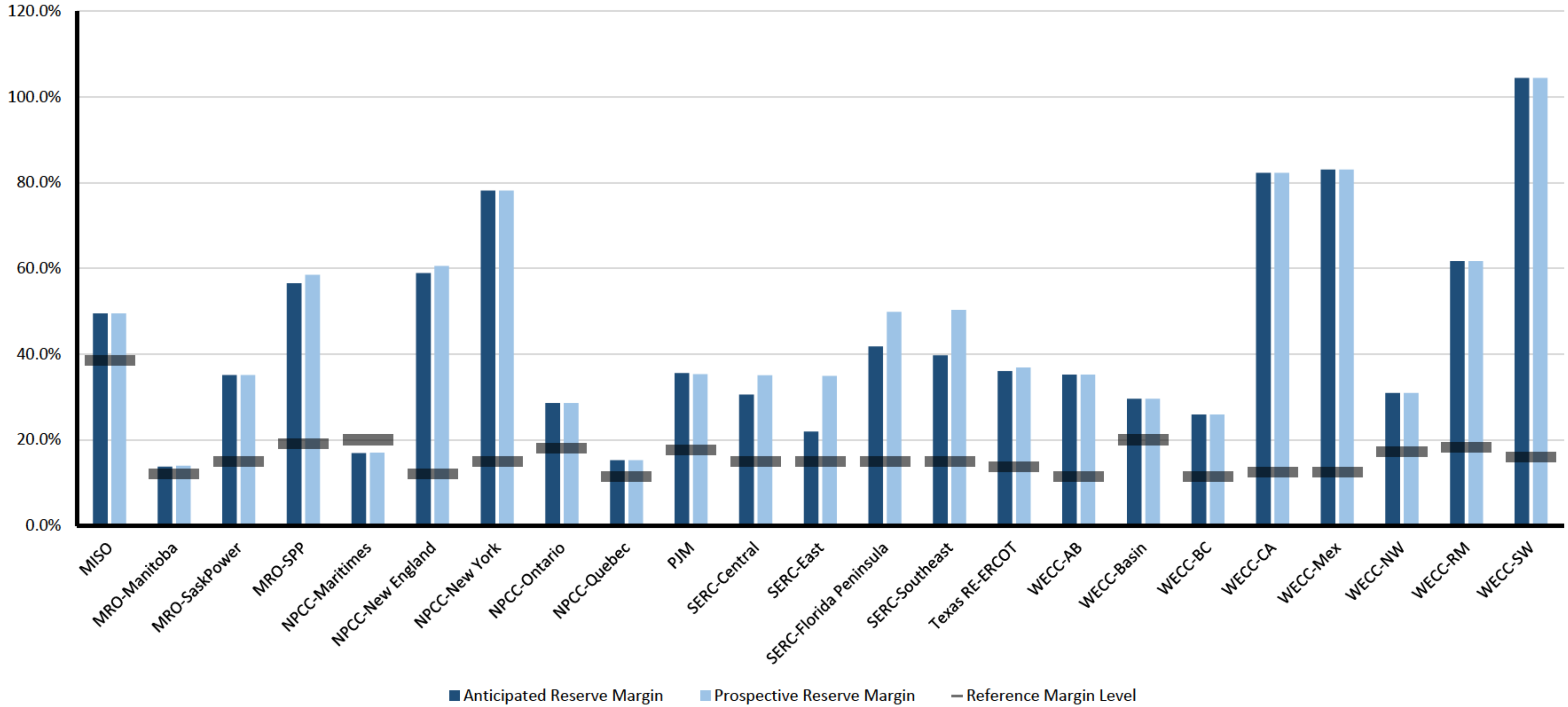


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] 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 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

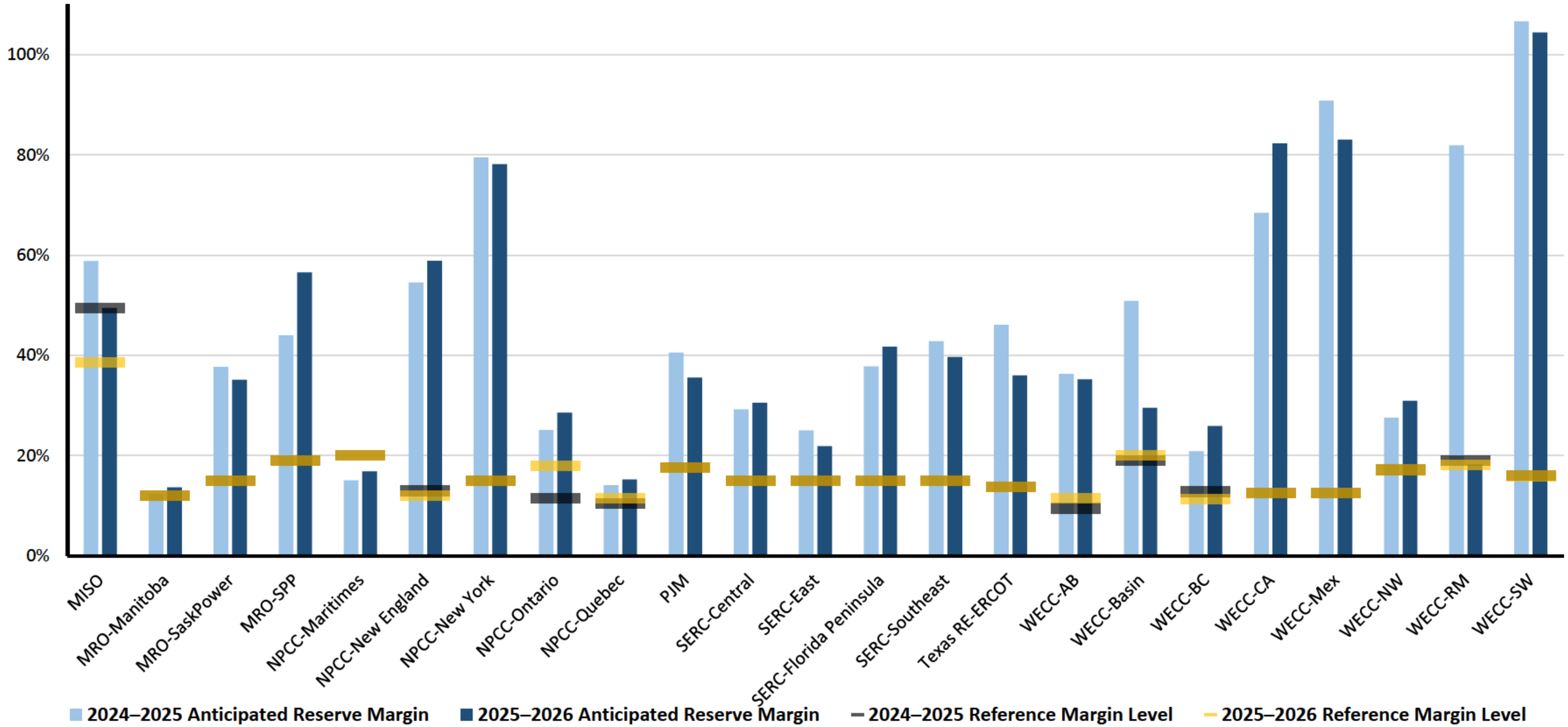


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

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 and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	184,711	43,556	23%	155,664	12,685	8%	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5.132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
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

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)

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 *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter 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 *2024–2025 WRA*.

[4] Values from NERC Generator Availability Data System for the 2024–2025 winter 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 2024–2025 winter risk period scenarios in the *2024–2025 WRA*.

[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.

*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.

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-60:
Department Press Release on Centralia Order

U.S. DEPARTMENT of ENERGY

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

“The last administration’s energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won’t let that happen,” said **Energy Secretary Wright**. “The Trump administration will continue taking action to keep America’s coal plants running so we can stop the price spikes and ensure we don’t lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining.”

According to DOE’s Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment warns that "extreme winter conditions extending over a wide area could result in electricity supply shortfalls." With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

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Energy Department Grants Woodside Louisiana LNG Project Additional Time to Commence Exports

December 16, 2025

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