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 1-21:
DOE Order No. 202-24-1

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds, torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;
(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;
(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. “Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT”;
(iv) Amount, type and formulation of any fuel used by each Specified Resource;
(v) All reporting provided under the Specified Resource’s operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;
(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and
(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.

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Jennifer Granholm
Secretary of Energy

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Exhibit 1-22:
Overview of Power Council's Resource Adequacy Approach

Resource Adequacy

Electricity does more than keep the lights on in the Pacific Northwest. It literally powers our economy. The absence or presence of an adequate electricity supply can either curtail or facilitate economic growth. In the worst extreme, an inadequate electricity supply can affect public health and safety, as in a blackout. Fortunately, such events are rare and when they do happen are most often caused by a disruption in the delivery of electricity (transmission lines), not the supply. However, there have been times – during extreme cold spells or heat waves – when the supply has been tenuous.

Adequacy refers to having sufficient resources to serve loads. In determining adequacy, the Council uses sophisticated computer programs (such as GENESYS) that simulate the hourly operation of the power system over many different futures. Each future is simulated under a different set of unknown parameters, such as water supply, temperature, wind and solar generation and thermal resource performance.

Historically in the Pacific Northwest, the biggest risk for power system adequacy was having a bad water year coincide with high loads. That is no longer the case. Planning for the future grid is becoming more complex with the changing resource mix, increased load growth from electrification, periods of extreme weather, and additional uncertainties.

To better address these challenges, in FY 2023 the Council's Power Division staff adopted a new, more sophisticated way to test whether the region's power grid has adequate resources by using multiple metrics. The Council was among the first power planners in the U.S. to move to a multiple metric approach.

The Council's previous adequacy metric of Loss of Load Probability (LOLP) focused on identifying the probability of a year with one or more simulated shortfalls from modeling that tested a range of hydropower, load, and wind conditions. The LOLP metric was effective for a power system heavily reliant on hydropower, thermal plants, and energy efficiency, where generation uncertainty was minimal and revolved around the coincidence of high loads and low water.

The Council evaluates shortfalls as a signal for needing emergency measures, such as a utility buying amounts of power from wholesale markets that are above market-import caps to meet peak demand. A multi-metric adequacy framework provides insights into the frequency, duration, and magnitude of potential shortfall events. An adequate system means all metrics stay within their respective thresholds.

The previous LOLP approach didn't offer insights into how large the shortfall would be, how long it would last, or what month or season it would occur in.

With a multi-metric approach, it is now possible to fully understand the shape and size of adequacy issues. This is a major advancement in helping the Council and the region plan for needed solutions.

The process to develop the multi-metric adequacy standard featured working with utilities and energy providers, including Bonneville Power Administration, throughout the region. Staff consulted with regional organizations such as the Western Power Pool, Pacific Northwest Utilities Conference Committee, Pacific Northwest Generating Cooperative, and the Columbia River Inter-Tribal Fish Commission. Finally, staff interviewed representatives and technical staff from public utilities commissions in Idaho, Oregon, and Washington.

Multiple metrics

Following an extensive public engagement and research process, the Council adopted the following adequacy metrics in FY 2023:

- **Frequency – Loss of load events (LOLEV)** is used to prevent overly frequent use of emergency measures.

The next three metrics are designed to protect against extreme shortfall events 39 out of 40 years. It means adequacy events do not last too long or have large magnitudes.

- **Duration – Value at Risk** sets a limit to protect against prolonged use of emergency measures. This helps to capture the risk of a summer heatwave or a winter storm.
- **Magnitude – Peak Value at Risk** protects against large magnitude emergency measure use.
- **Magnitude – Energy Value at Risk** protect against large aggregate use of emergency measures during a year.

The Council continues to refine these metrics by developing provisional thresholds, and will further evaluate them in advance of the next power plan process.

See the Resource Adequacy Advisory Committee for all current work.

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Exhibit 1-23:
Overview of Power Council's Approach to Load Forecasting

Explaining how the Council forecasts load growth for the Pacific Northwest power system

At an April 29 meeting that will be hosted online, staff will present results from a new load forecast for the Northwest

MARCH 20, 2025 | PETER JENSEN

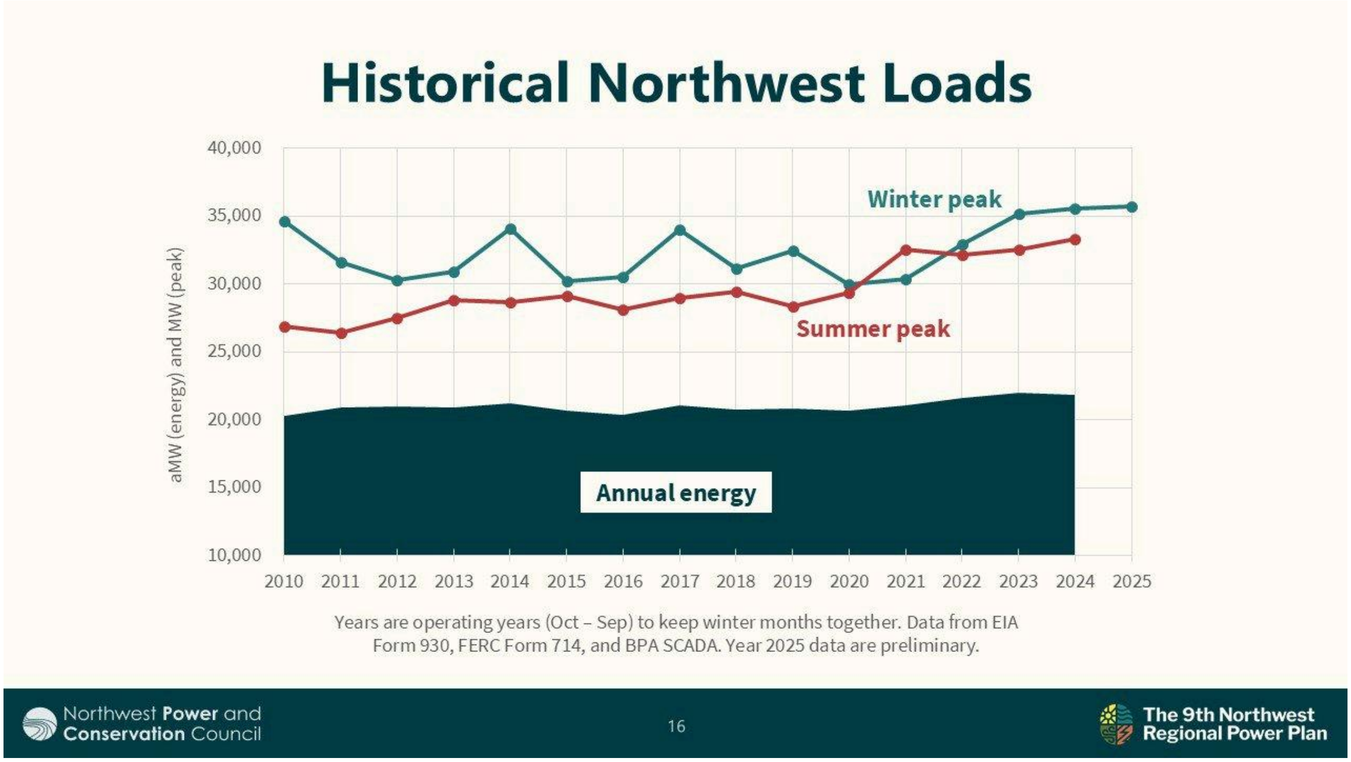
EVs are expected to be a significant source of load growth in the Northwest. Image credit: Department of Energy

When you need to see in the dark, which will illuminate the terrain better – a flashlight or an aerial flare? This spring, Council Power Division staff will be using the latter approach to produce a new 20-year load forecast for the future of the Pacific Northwest's power system.

At March's Council meeting, Senior Energy Forecasting Analyst Steve Simmons and Senior Power Analyst Tomás Morrissey explained their analytical approach and methodology to load forecasting (read presentation | watch video). "We're going to try to illuminate a pretty large area," Simmons said.

This was the first of a multi-part discussion on load forecasting this spring, which is a key component of the Ninth Northwest Power Plan. At a meeting on April 29 that will be hosted online, staff will present comprehensive results from the new load forecast for the Northwest.

The Council's approach to load forecasting



In Feb. 2025 during a cold snap, the Northwest power system peak load reached 35,700 MW, which sets a new post-Direct Service Industry record high for the region. The peak load during a January 2024 winter storm was 35,600 MW. However, the total energy needed in January 2024 was 2,000 aMW higher than what was needed in February 2025.

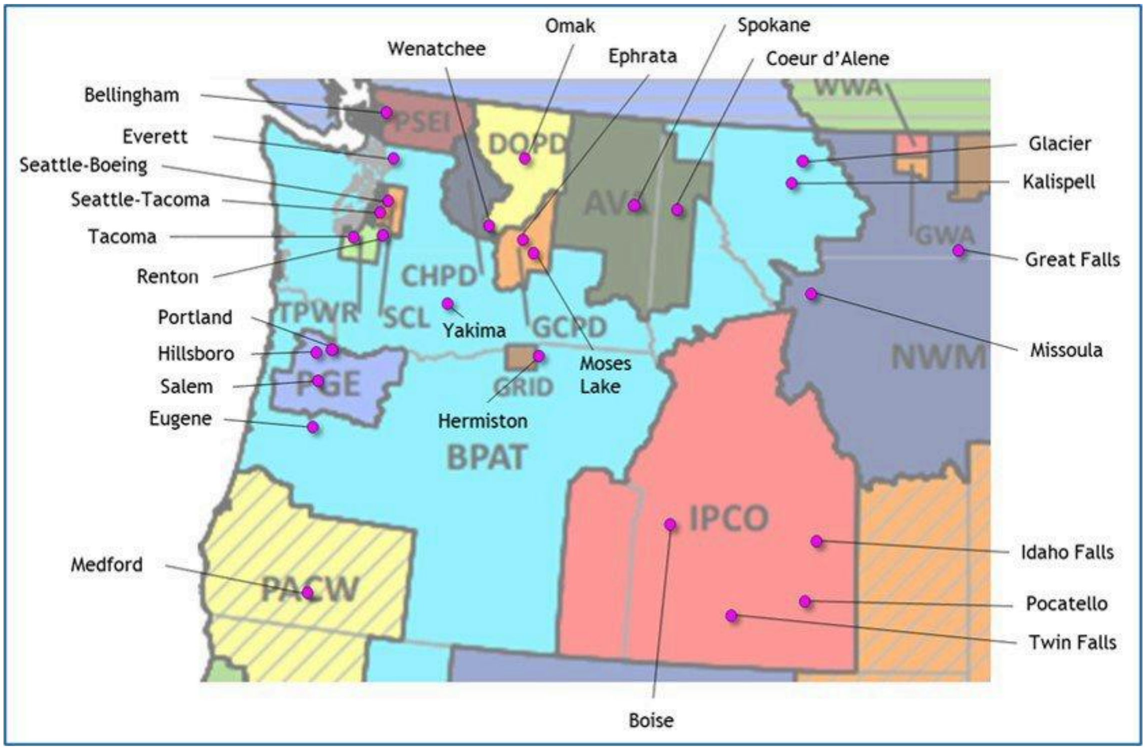
As the chart above shows, growth in electricity demand does not travel upward on a linear trajectory. It ebbs and flows over time. This is true for both annual energy and peak demand. This demonstrates the need for greater flexibility in forecasting, and to capture a range of possible futures rather than one future plotted precisely on a graph. This is why the Council uses forecast ranges instead of an exact "best guess" number. This has been the Council's approach ever since its first Power Plan in 1983. This method, innovative for the time, was developed at a moment when the Northwest's power system had veered badly off course due to errors in load forecasting in the 1960s and 1970s, resulting in disastrous over-building of the region's electricity generation resources.

While load forecasting computer modeling systems, analysis, and methodologies have all advanced tremendously since 1983, electricity demand growth still ebbs and flows over time in similar patterns. For the Ninth Plan, the Council's forecasts of the Northwest's power demand will consider several possible trajectories, which capture and reflect a range of future uncertainties for how much electricity demand materializes on the Northwest's power system, and by when. This range of uncertainty is core to successfully planning for the future.

Improvement in computer modeling, growing data complexity

At March's meeting, Simmons noted that the goal is to create an accurate and comprehensive forecast of demand for electricity in the region across 20 years. To do that, staff needs to analyze the region's current and historic energy use, which helps to gain an understanding of what might drive changes to future demand. That requires building a computer model. The demand forecast is an output from this model, which is highly input data driven and is getting more complex for the Ninth Plan.

In producing the 2021 Power Plan, staff continually bumped up against limitations to their old models' ability to do long-term load forecasting, among other essential tasks in power planning. In 2023 staff contracted with Itron, a company offering energy forecasting software tools, to upgrade the Council's long-term load forecasting.



The Council has upgraded its load forecasting capabilities for the Ninth Power Plan. Power system analysts will be able to produce annual, monthly, and hourly forecasts of load across 20+ years for the region as well as individual utilities' balancing authorities, shown on the map above. They'll also include data for 27 weather stations around the Northwest (noted with purple dots on the map).

Power system analysts now have the capability to produce annual, monthly, and hourly forecasts of load across 20+ years for the Northwest as well as for 13 individual utilities' balancing authorities. They'll also be able to include data from 27 weather stations in Oregon, Washington, Idaho, and Montana, which will allow staff to forecast changes related to weather conditions. Forecasts will represent residential, commercial, and industrial sectors, as well as for electric vehicles, data centers, electrification, and rooftop solar. Those added capabilities have made data inputs and management more complex and challenging, Simmons said. Staff is taking care to monitor quality and check for accuracy for all inputs going into the model to develop the load forecast.

Simmons reviewed data sources staff is working with for this load forecast:

Building stock – new and existing by type

- Units
- Square feet

End use technology, such as space heating or cooling in buildings

- Fuel type
- Unit saturation
- Energy efficiency
- Load shape

Economic conditions

- Population
- Employment income

Quantitative and qualitative data and analysis on industries and the tech sector, including data centers and chip fabrication facilities

Future weather

Electric Vehicles

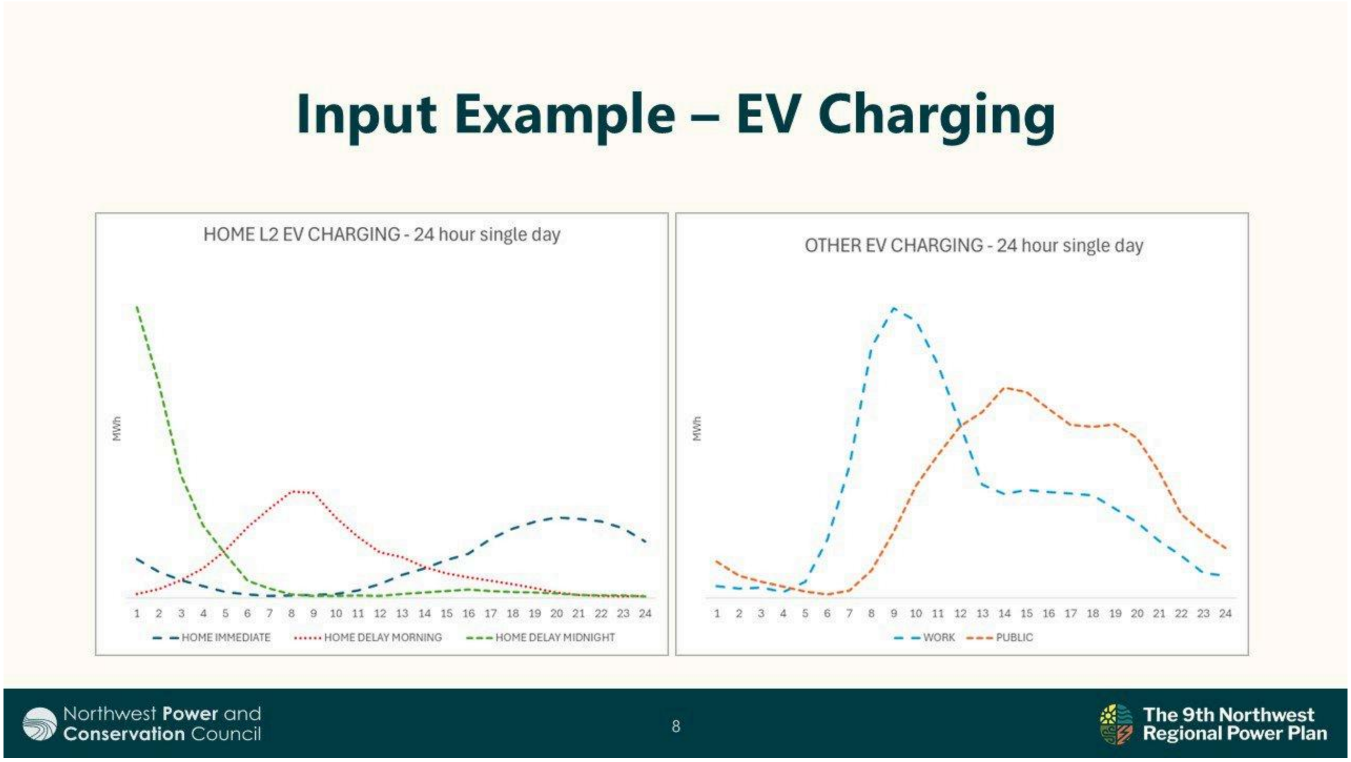
- Registration & Sales
- Usage
- Load shape

Rooftop Solar

- Installations and shape

Load shapes and future demand trajectories

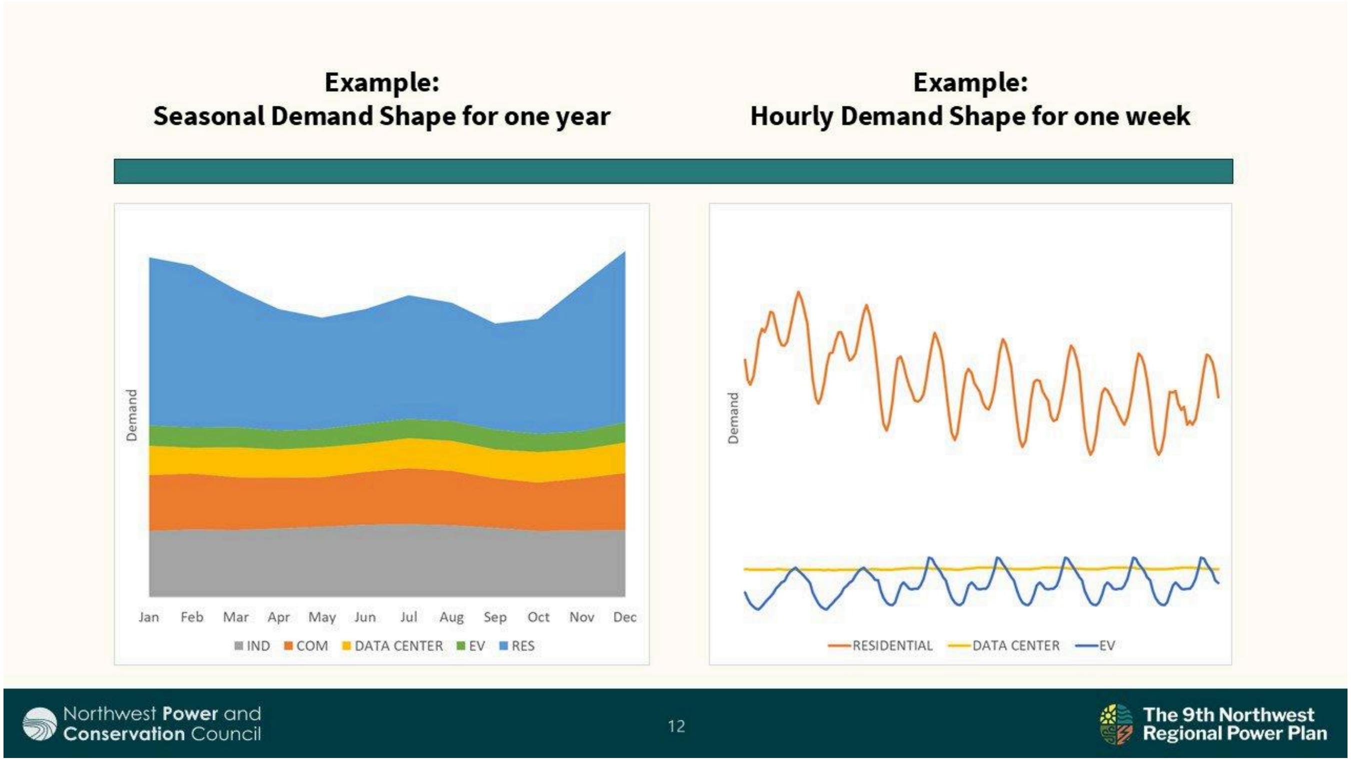
A vital part of the Ninth Power Plan will be to evaluate cost-effective energy efficiency and demand response potential and compare and contrast it with other resource options to meet future energy needs in the Northwest. Therefore, the initial load forecast will freeze efficiency at today's levels and assume no demand response. This will result in a forecast that might be higher than actual long-term loads, or have larger peaks. For example, unmanaged electric-vehicle charging that often occurs in after-work hours can coincide with other peak hour power needs. Utilities pursuing demand response could manage the charging in several different ways that have less impact on power system peaks – such as after midnight. The initial load forecast will assume unmanaged charging, leaving the demand response potential of managed charging as an option to the model.



Near the end of the power planning cycle, once the Council has made decisions on how much cost-effective efficiency, rooftop solar, and demand response should be included, staff will re-run the load forecast to get the final version to include in the Ninth Plan.

Staff will also be analyzing three demand characteristics – magnitude, timing, and shape – for six key futures: weather, economic growth or stagnation, electric vehicles, data centers, building electrification, and hydrogen production.

- Future weather affects summer loads' peaks and the timing will occur throughout the Ninth Plan's 20 year horizon.
- Electric vehicles affect residential loads' peaks and will have a large impact mid-way through the 20-year period. EVs will be a significant source of demand in some zones, such as Western Washington and Western Oregon, while not as much in others.
- Data centers will be single large loads that will come on early in the plan period. The profile will be flat. It will be significant in some zones but not others.
- Building electrification will affect winter loads' peaks, but will have a larger impact late in the 20-year period.
- Hydrogen production will be a single large load with a flat profile that will also be late in the 20-year period.



Understanding the differences between loads' magnitude, timing, and shape down to monthly, daily, and hourly levels will help the Council's power planners identify the right cost-effective suite of resources to add to the Northwest's power system so it continues to be adequate, efficient, economical, and reliable.

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Exhibit 1-24:
Sylvan & GridLab Independent Evaluation of E3 Presentation

Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges

SYLVAN ENERGY ANALYTICS

Sylvan Energy Analytics

January 2026

This work was sponsored by GridLAB

Who we are

SYLVAN
ENERGY ANALYTICS

Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.

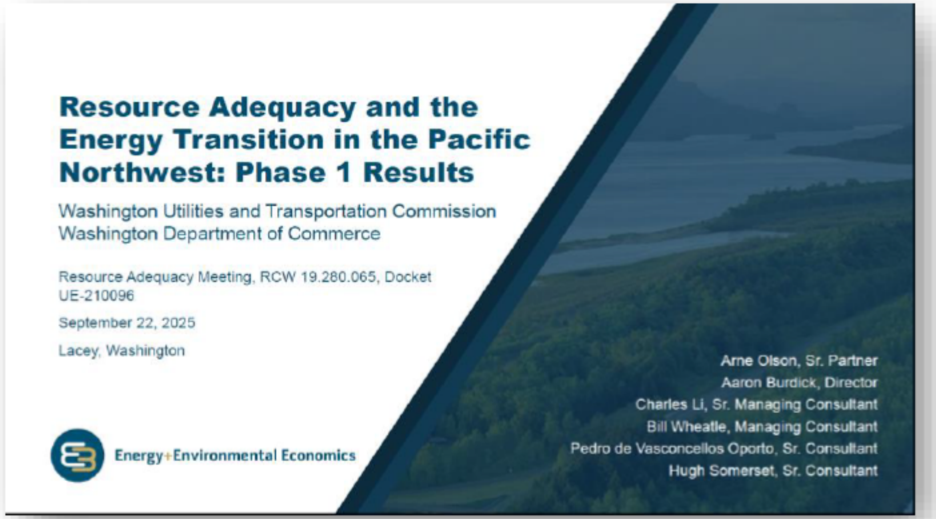
GridLAB

GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
  - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
  - It projected a 9 GW shortfall by 2030 across the “Greater NW,” with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
  - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
  - Phase 2 is underway and is expected to be released in early 2026
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3’s analysis and findings and identify near-term opportunities to support regional RA



Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from “In-Development” Firm Resources	-	296	407	580	770	1,114
ELCC from “In-Development” Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

Overview

Problem statement: If we take the E3 study Phase 1 results at face value, the region needs solutions well before significant amounts of new infrastructure can come online

Objective: Understand what drove E3's Phase 1 findings and explore the potential contributions of near-term solutions that may not be considered in Phase 2 of their analysis

Scope:

- Conduct a methodological review in key areas that could impact RA results, including large load flexibility, hydro dispatch flexibility, imports & coordination with California, and retirements & conversions
- Conduct an independent evaluation of the near-term winter RA challenge in the Pacific Northwest
  - Develop multiple load scenarios based on recent load trends and various projections of future data center demand
  - Examine winter resource adequacy challenges in 2030 based on the weather and hydro conditions experienced in January 2024 (the most recent example of highly constrained winter conditions in the Pacific Northwest)
- Identify near-term opportunities to support regional resource adequacy based on findings

Executive Summary

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High
Hydro flexibility	• E3 study may underestimate weekly energy shifting available from hydro dispatch • E3's load following hydro dispatch assumption may overlook contributions from short-duration storage	Uncertain (requires further study)
Imports and coordination with California	• E3 study assumptions may slightly underestimate import winter capability • Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)	Low
Retirements and conversions	• Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation • E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)	Low-to-moderate

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High

Because of the high potential near-term impact of large load flexibility, most of our analysis focuses on these two highly related questions:

1. How much of the projected need is being driven by data centers (i.e., “new large loads”)?
2. What is the potential for management of new large loads to avoid the most catastrophic consequences of potential supply shortages during extreme weather conditions?

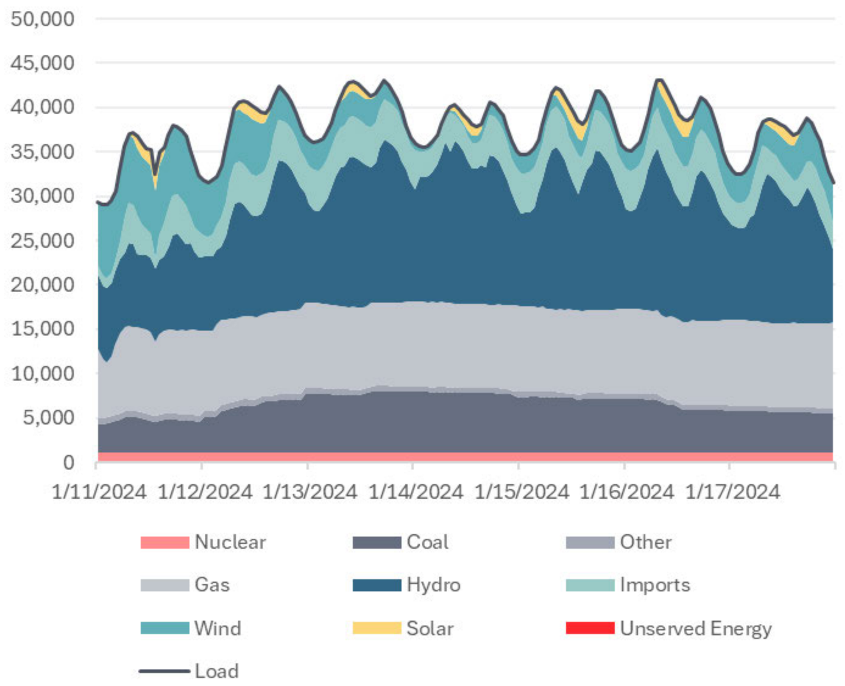
Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

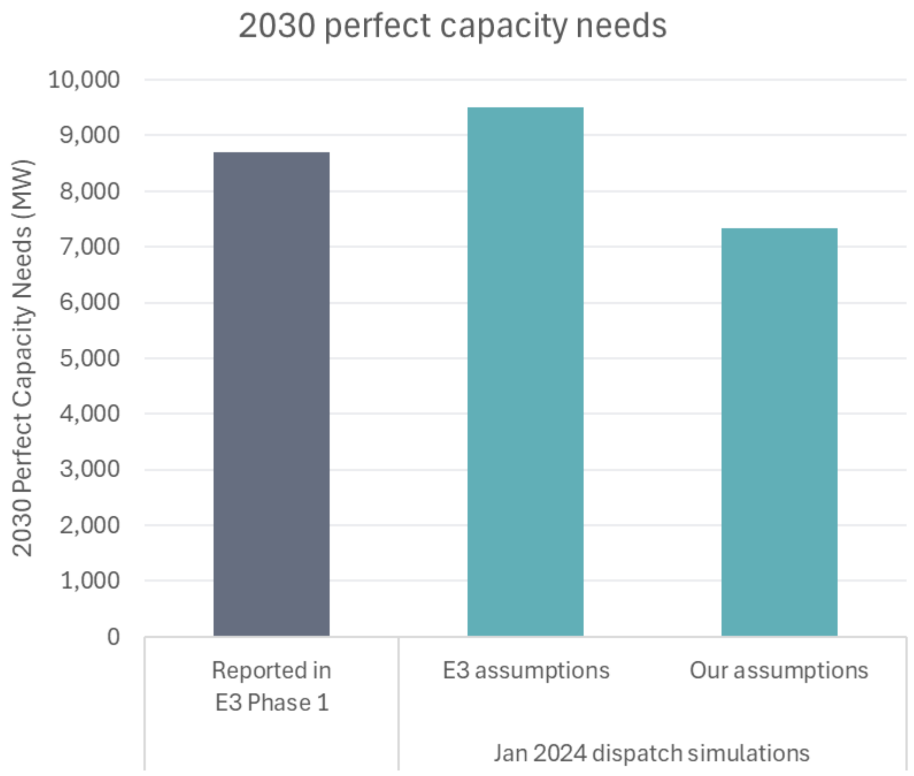
1. Developed dispatch simulation for the “Greater NW” that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
  - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
  - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas), except Centralia 2
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



Alternative 2030 load scenarios

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

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Finding #1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends

We estimate winter capacity needs in 2030 of 1.0 GW – 4.9 GW after accounting for coal-to-gas conversions and resources in development

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

Finding #2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

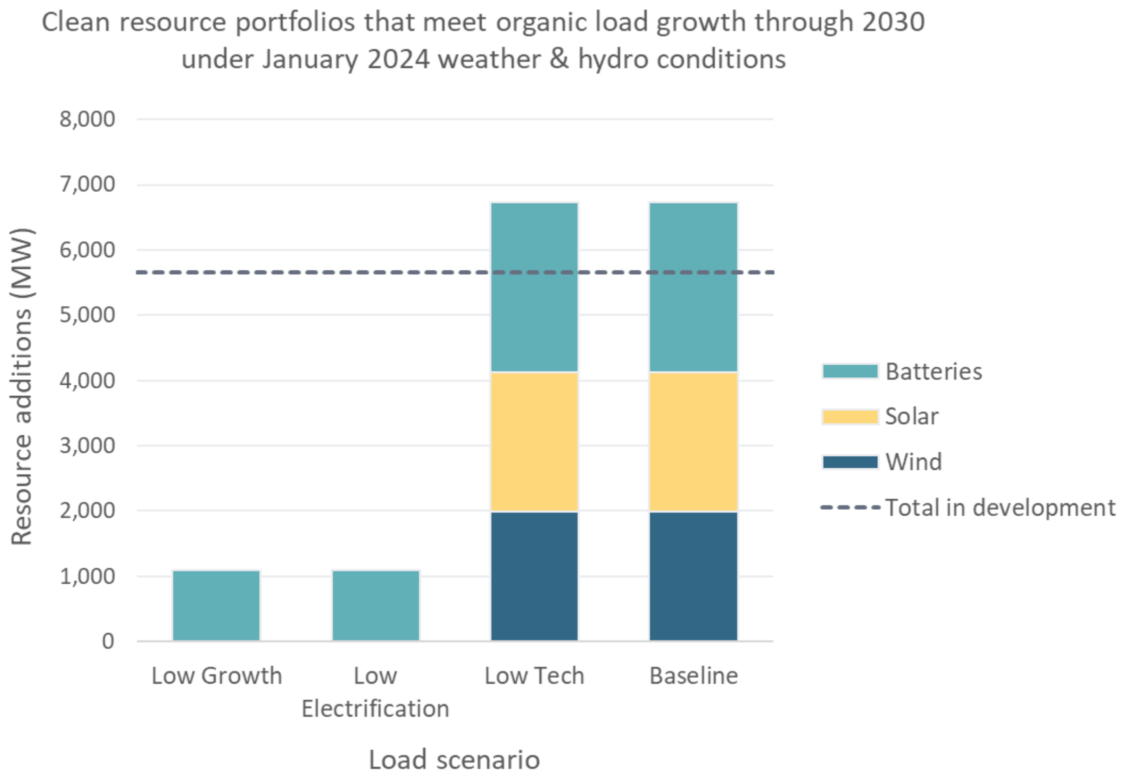
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	Reported by E3 in Phase 1
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW
+ Large load flexibility	0.0 GW	0.0 GW	1.1 GW	1.2 GW	3.1 GW	NA

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

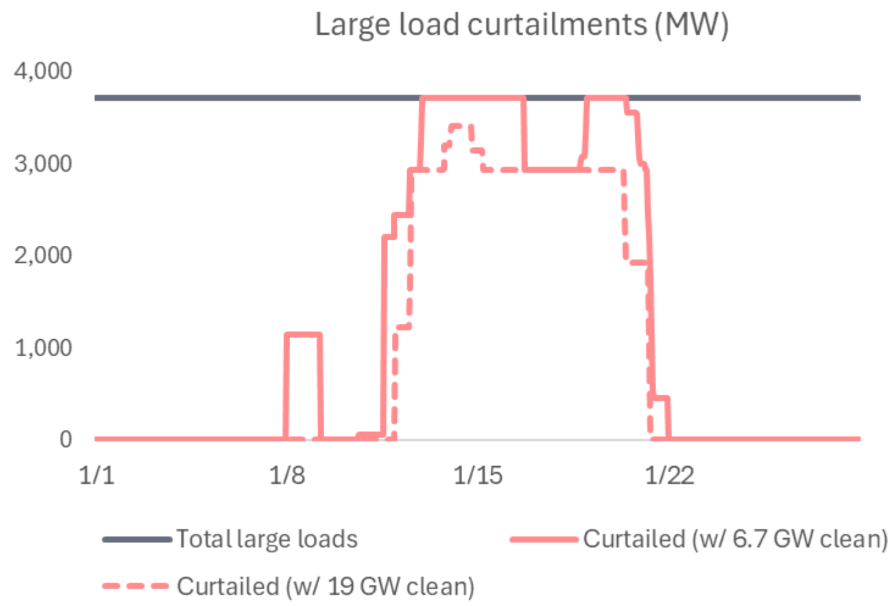
Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- We estimate that less than 7 GW of new wind, solar, and batteries are adequate to avoid supply shortages among non-data center customers under January 2024 weather & hydro conditions in 2030 across our four load scenarios
- Under the E3 Load Forecast Approximation (with more electrification and fewer data centers than our load scenarios), supply shortages cannot be avoided even if all proposed clean resources (19 GW) come online by 2030



Finding #4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events

Without these additional resources, we estimate that large load curtailments could range from 0 hours to 9 days under January 2024 weather & hydro conditions, depending on the load scenario and clean resource buildout



Load scenario	Large load curtailments in 2030 under January 2024 weather & hydro conditions
Low Growth	0 hrs
Low Electrification	2.5 - 4.6 days
Low Tech	2.3 - 6.2 days
Baseline	7.0 - 9.3 days

Note: Clean resource additions range from the greater of the resources under development and the resources needed to meet organic load growth to all proposed clean resources as of December 2024 (19 GW)

Finding #5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

We estimate that large load management could reduce average outages among other customers during critical winter weather conditions from 19 hours to 0.1 hours (assuming only resources already in development come online by 2030)

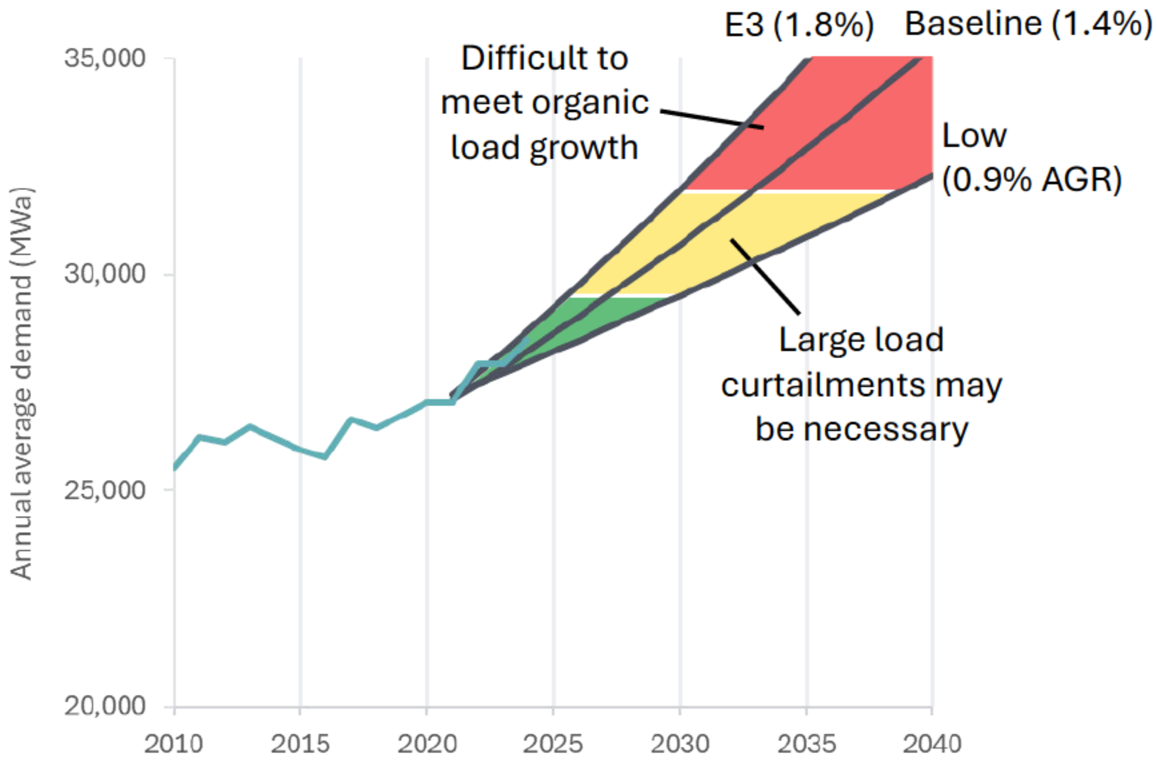
Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario
(assuming only resources already in development come online)

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Finding #6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency)
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

Extrapolated* organic load growth trajectories and resource adequacy challenges



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

Near-term opportunities identified to support regional RA

Policy

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Analytical Details

Evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the Pacific Northwest that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
   - Resources in development
   - Emergency large load management
   - Additional proposed clean resources

Some technical notes

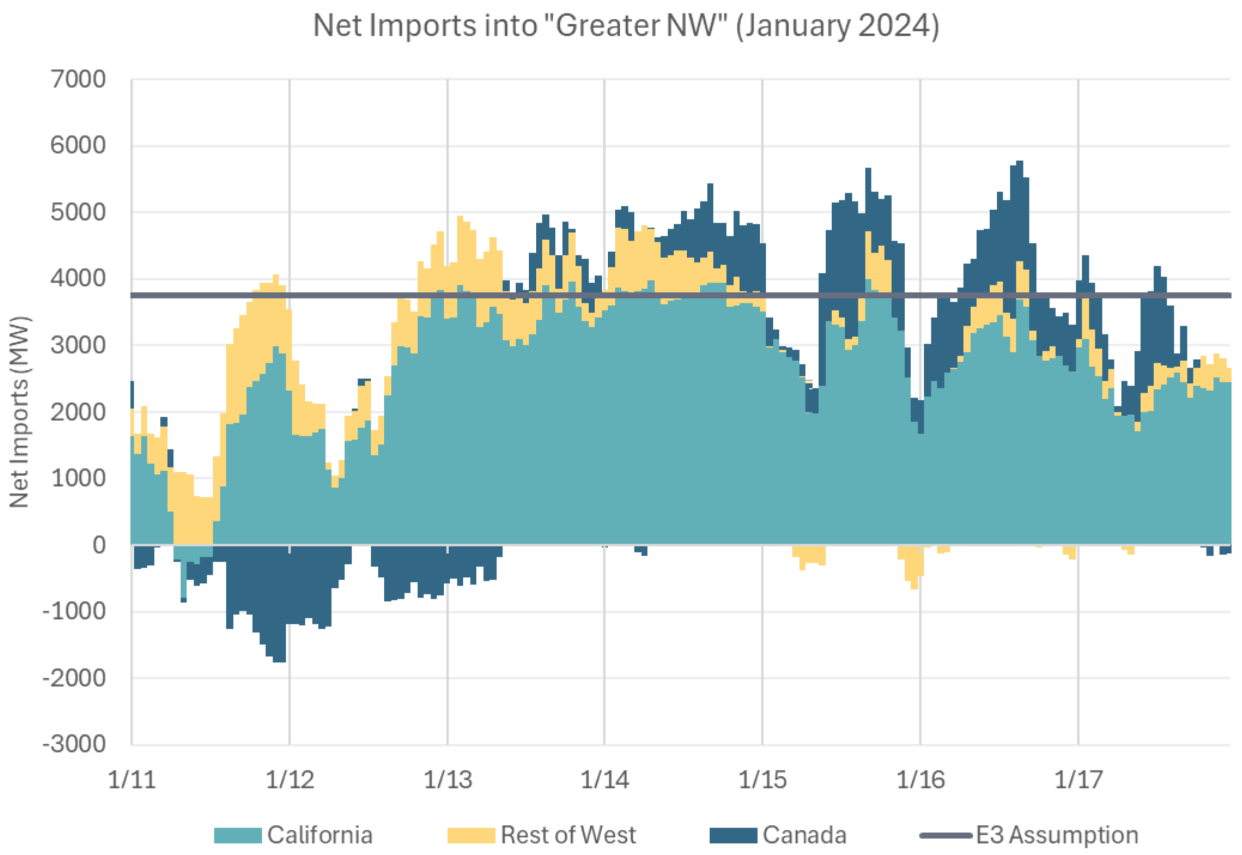
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our "Greater NW" footprint with E3's due to time and data limitations. Loads and resources likely differ between the analyses and load comparisons focus on load growth rates rather than total loads to account for these differences
- Perfect capacity needs were identified by minimizing the maximum observed unserved energy across the month
- Potential customer outages were identified by equally penalizing total and maximum unserved energy to better reflect operations

Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	Optimized with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: Constrained flows between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	<u>Total: 5,000 MW</u> Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	<u>Total: 3,750 MW</u>
Canadian entitlement	2024 benchmark: 660 MWa net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWa	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired <u>Coal-to-gas conversions of Centralia 2</u>, Dave Johnston 1 & 2, Naughton 1 & 2	Existing and in development resources based on WECC ADS Dave Johnston 3 and <u>Centralia 2 retired</u> Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

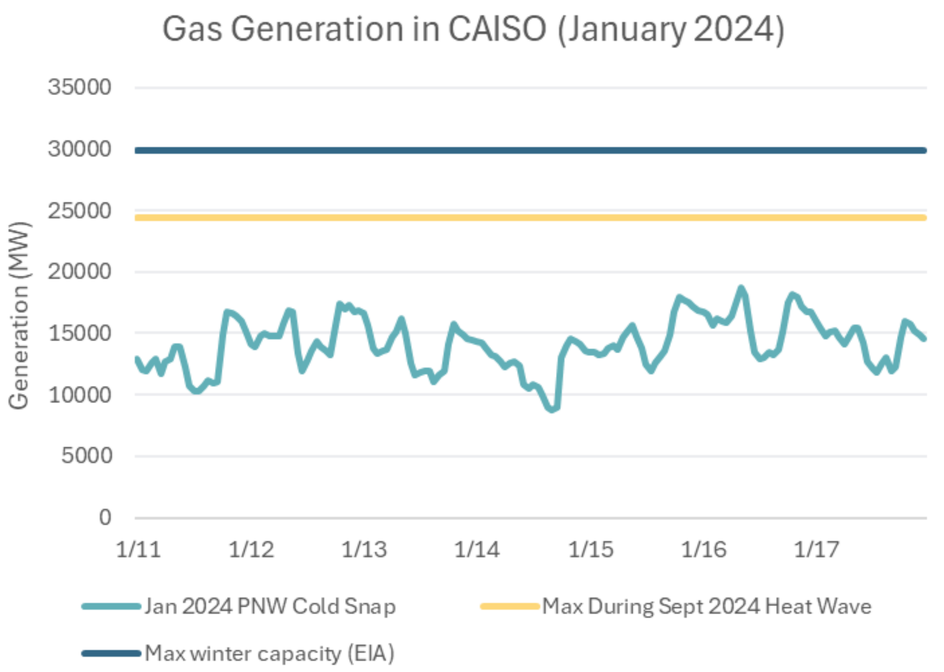
Winter import constraints

- The E3 study assumes 3,750 MW of imports are available in all hours based on imports during the January 2024 cold event
- Net imports into the “Greater NW” exceeded 3,750 MW in 102 hours in January 2024 and exceeded 5,000 MW in the most constrained hours
- The 3,750 MW limit aligns well with imports from California during the event, but may neglect additional import capability from Canada and the rest of the West



Transmission, not available supply, limited imports

- Much of the gas fleet in California went unused during the January 2024 event (i.e., there was not a shortage of regional generating capacity in the West)
- However, South-to-North transmission flows between California and the Pacific Northwest were constrained by operating limits
- South-to-North operating limits on COI and PDCI are tighter than North-to-South limits
  - Max N-to-S during Sept 2024 heatwave: ~5,500 MW
  - Max S-to-N during Jan 2024 cold snap: ~3,800 MW



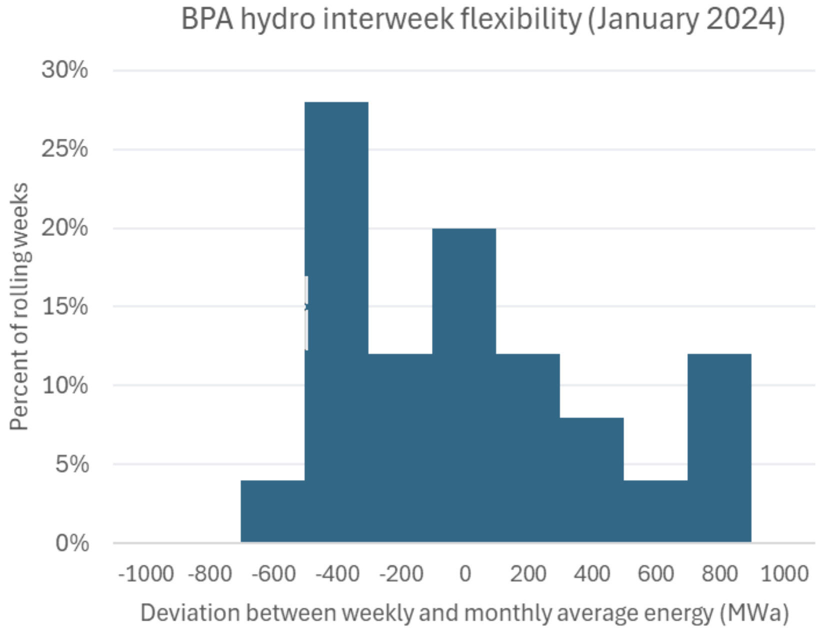
Near-term opportunities to support increased imports during winter events:

- ➢ Prioritize transmission studies and upgrades that support increased S-to-N flows into the PNW during the winter
- ➢ Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest

Hydropower dispatch

Study review:

- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize between hydro and other resources, including short-duration batteries
- Analysis into BPA hydro dispatch in January 2024 suggests that any given week could have access to as much as 880 MWa (14%) of additional hydro beyond the monthly average energy



Outstanding substantives questions:

- How do hydro operators value stored water when dispatching their hydro fleets? Does it adequately account for the value of supporting winter reliability over longer timescales (i.e., future days, weeks, or months) or is hydro dispatch over-optimized for short-term economics?
- How will day-ahead market participation affect this tradeoff between short-term revenues and winter reliability value?

Near-term opportunity:

➢ Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits

Retirements and conversions

Study review:

- E3 confirmed the 8,689 MW identified need assumes that coal plants retire instead of undergoing coal-to-gas conversions
    - E3 analysis suggests that capacity needs could be 850 MW smaller with coal-to-gas conversions included

Our approach:

- Include all announced coal-to-gas conversions to avoid over-stating incremental needs
    - While conducting the analysis, Transalta announced the conversion of Centralia 2 to gas. This update was incorporated into our final simulations.

	Winter Capacity	E3 initial need evaluation	Our analysis
Dave Johnston 1	99 MW	Retired	Converted to gas
Dave Johnston 2	106 MW	Retired	Converted to gas
Dave Johnston 3	220 MW	Retired	Retired
Naughton 1	156 MW	Retired	Converted to gas
Naughton 2	201 MW	Retired	Converted to gas
Centralia 2	670 MW	Retired	Converted to gas
Total retired		**1,452 MW**	**220 MW**
Total converted to gas		**0 MW**	**1,232 MW**

Outstanding substantive question:

- Some of PacifiCorp's coal-to-gas conversion plans suggest winter downtimes, which may be avoidable by pushing the schedule out or accelerating it by a matter of months. How does winter reliability factor into scheduling for coal-to-gas conversions?

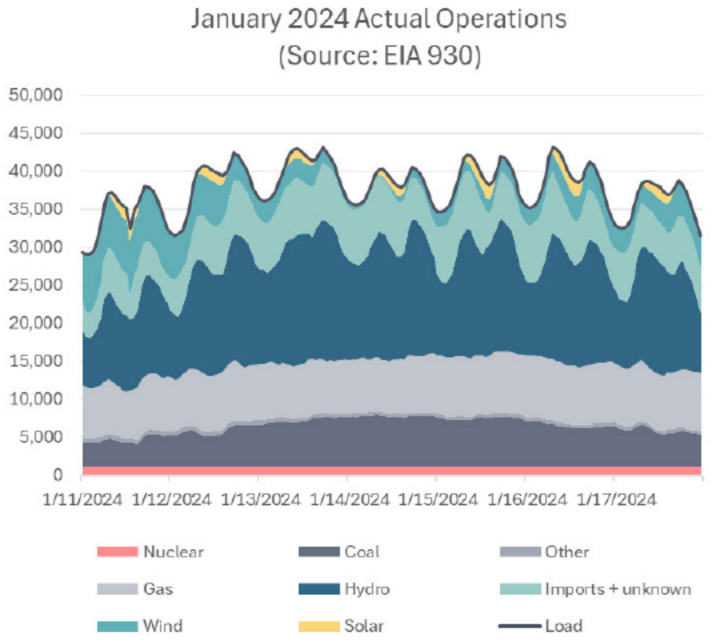
Near-term opportunity:

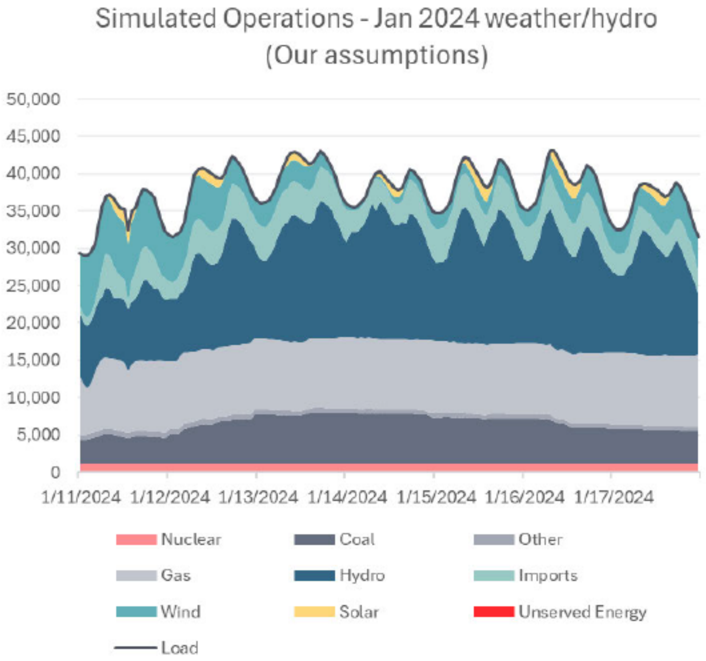
➢ Schedule coal-to-gas conversion activities to minimize winter downtimes

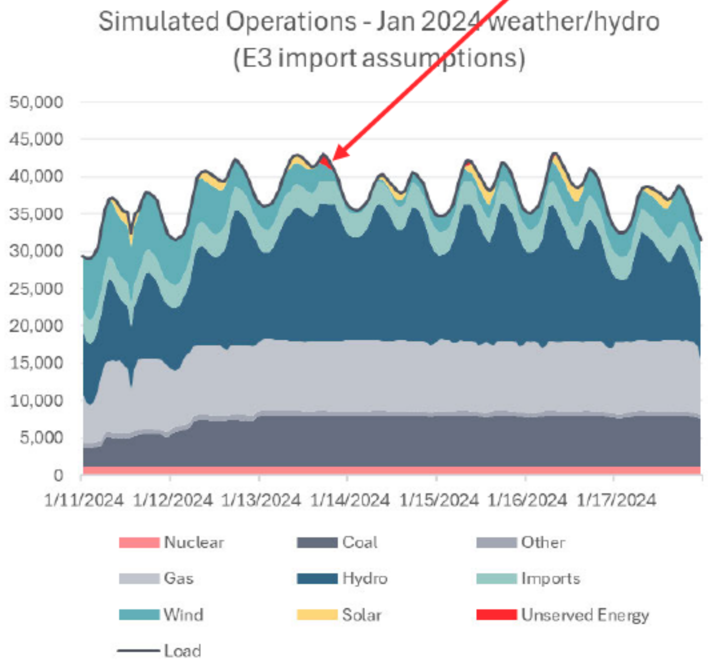
2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



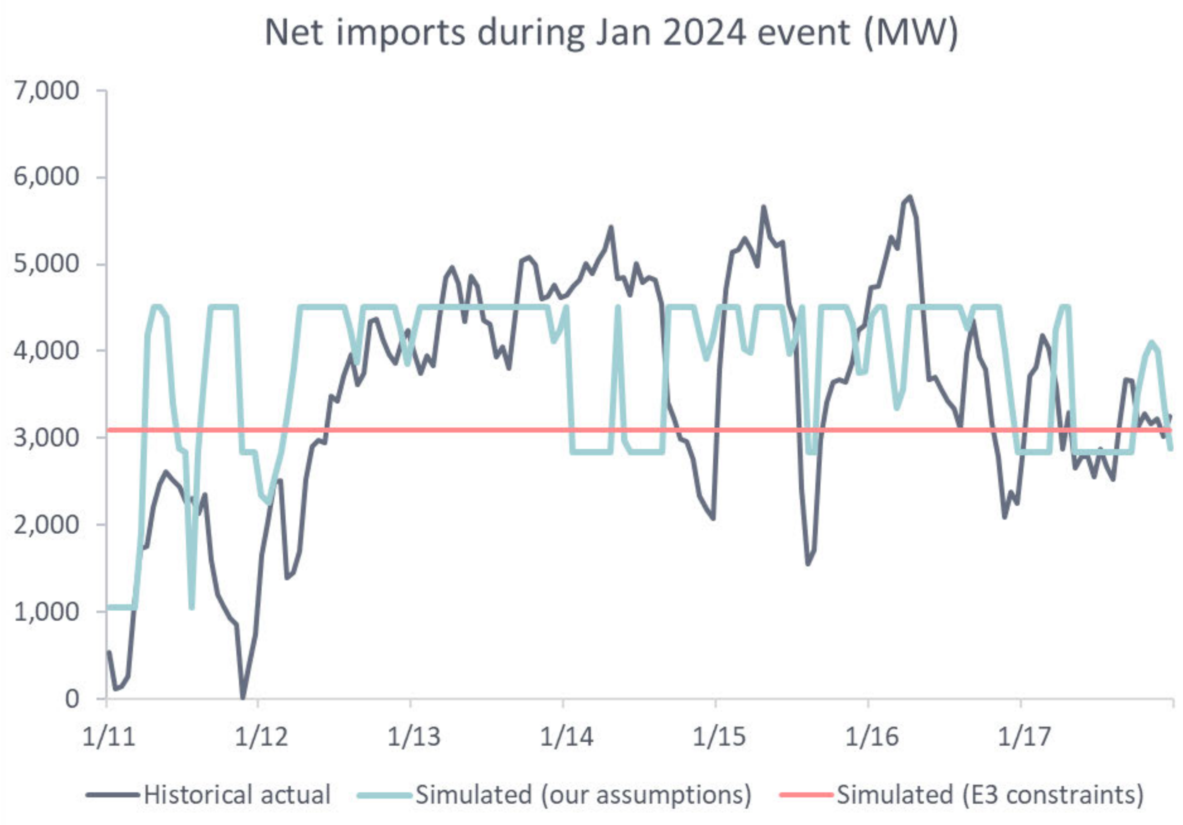




*Actual and simulated operations have different classifications for some resources that are interconnected to BPA, but not reported by BPA (or other BAs) in EIA 930. These resources are simulated explicitly and grouped by technology in the simulated operations plots, but fall within "Imports + unknown" in the actual operations plot (on the left)

2024 benchmarking

- Additional imports in our assumptions are adequate to clear unserved energy in Jan 2024 benchmarking exercise
- Average net imports between 1/11 and 1/17 are similar across historical actuals and simulations:
  - Historical actuals: 3,508 MW
  - Dispatch simulation with our assumptions: 3,811 MW
  - Dispatch simulation with E3 constraints: 3,090 MW
- Reminder: simulations reflect system capability, not fully economic dispatch



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- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
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- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
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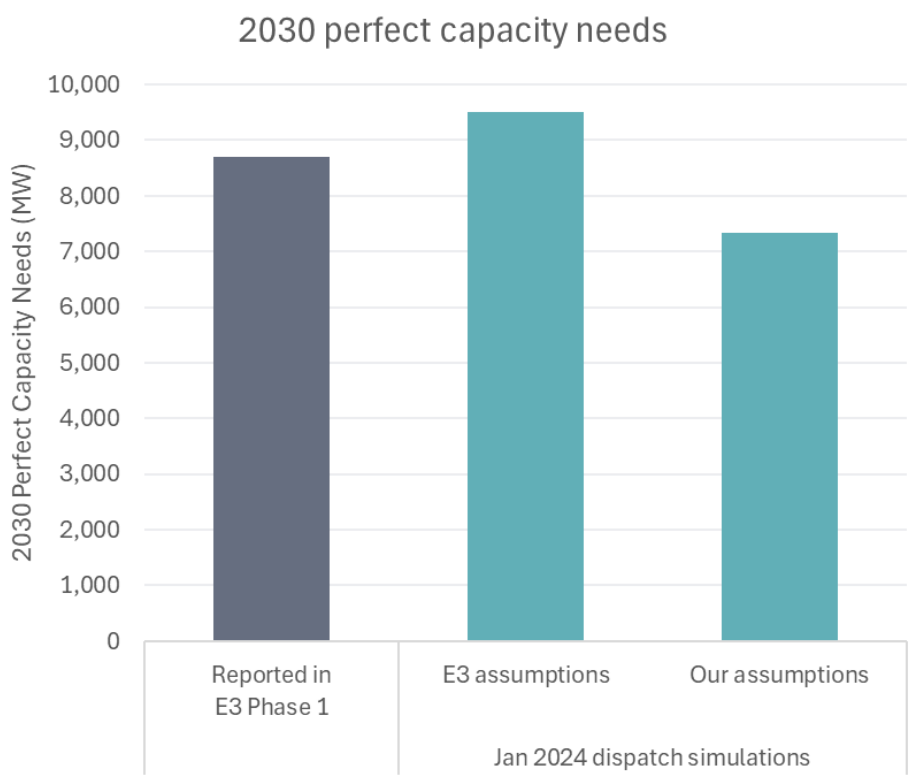


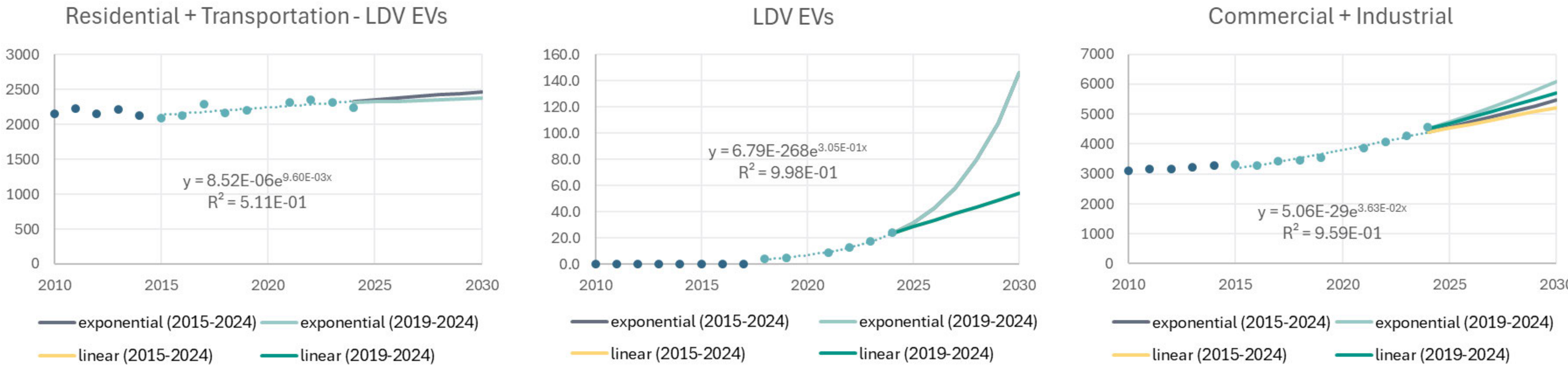
Electricity demand scenarios for 2030

- The E3 study relies on E3's internal load forecast, which comes from their bottom-up PATHWAYS model and internal data center demand forecasts
- E3's annual energy tracks closely with PNUCC's 2025 forecast (with aligned footprints), which is based on utility forecasts and projects 3.2% annual growth
- Data centers vs. electrification
    - E3 suggests that their forecast includes higher EV and electric space heating than the PNUCC forecast, which is potentially offset by a lower data center forecast
    - PNUCC has not collected information from their members to clearly distinguish between organic load growth and data center loads
- To understand the sensitivity of 2030 resource needs to future load growth and data center flexibility, Sylvan developed additional top-down load growth scenarios from available public data

Estimating organic load growth trends

- “Organic” load growth includes everything but new large loads (i.e., includes electrification)
- We estimated plausible ranges of sector-specific loads by fitting linear and exponential functions to recent historical sector-specific loads
- Data sources: EIA historical sales by sector and state, EIA historical LDV EV electricity consumption by state

Example: estimation of organic load growth trends in Oregon



Organic load growth scenarios

- **Baseline organic load growth:** upper bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls between NWPCC "Mixed bag" and "Persistent high growth" load scenarios (excluding data center and H_2 demands)
- **Low organic load growth:** lower bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
  - Falls just below NWPCC "Mixed bag" load scenario (excluding data center and H_2 demands)
- Note: comparisons are high level and indicative, as footprints vary between forecasts and NWPCC loads assume fixed energy efficiency

Scenario	Average annual organic growth rate through 2030
NWPCC[2] "Persistent high growth"	~1.9%
E3 Forecast[1]	~1.8%
Baseline Organic Growth	**1.4%**
NWPCC[2] "Mixed bag"	~1.0%
Low Organic Growth	**0.9%**
NWPCC[2] "Persistent low growth"	~-0.1%

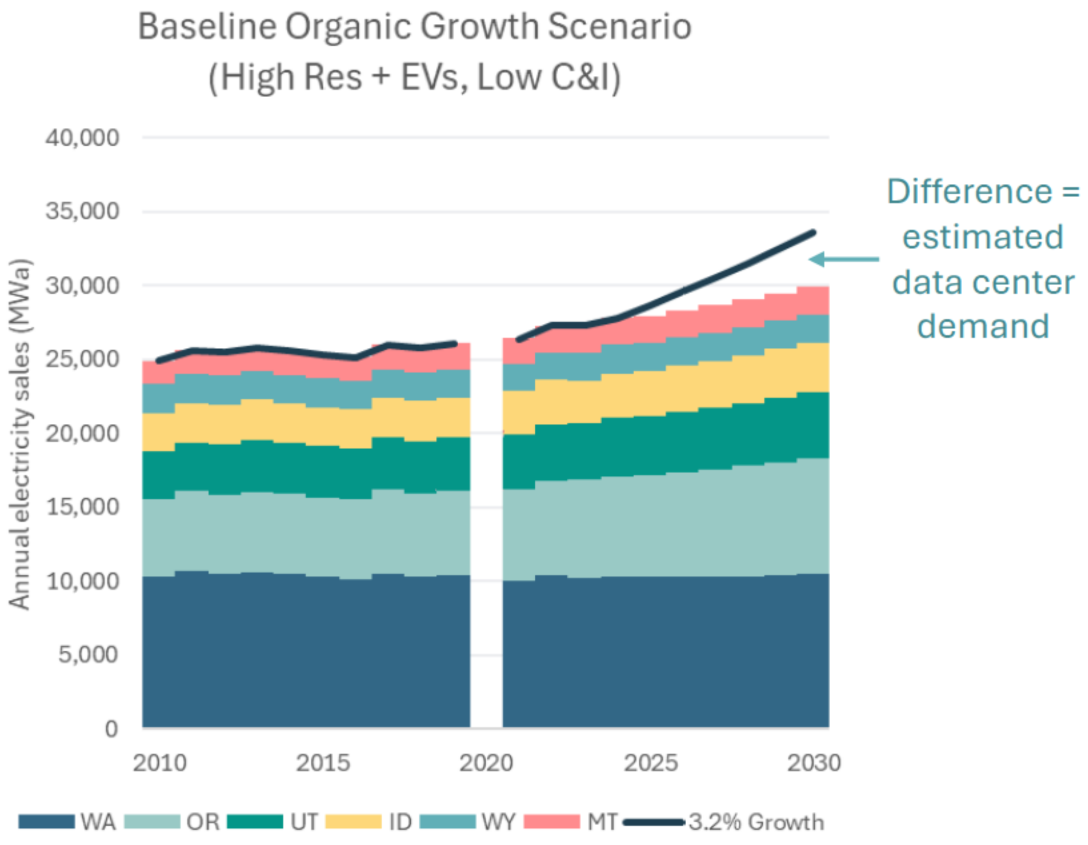
[1]E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

[2]NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H_2 demand on slide 33 from total forecasted demand scenarios on slide 46 of the Ninth Plan Demand Forecast Part 2 (https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf)

Data center demand scenarios

- **Baseline data center demand:** estimated as the difference between the organic load growth forecast and 3.2% total load growth reported by PNUCC
    - Higher than E3 forecast, between Mid and High forecasts from the NWPCC
- **Low data center demand:** E3 data center forecast

Scenario	PNW MWa (WA, OR, ID, MT)	"Greater NW" MWa (PNW + UT + WY)
Baseline Scenario	**2,931**	**3,717**
Low Scenario (E3 Data Center forecast)	**1,100**	**1,700**
NWPCC Low Tech Load	~1,400	NA
NWPCC Mid Tech Load	~2,200	NA
NWPCC High Tech Load	~4,600	NA



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Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
Historical growth in electricity sales (2019-2024, excluding 2020)			*1.3%*

All alternative load scenarios envision accelerated load growth relative to the last 6 years

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

Detailed findings

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  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

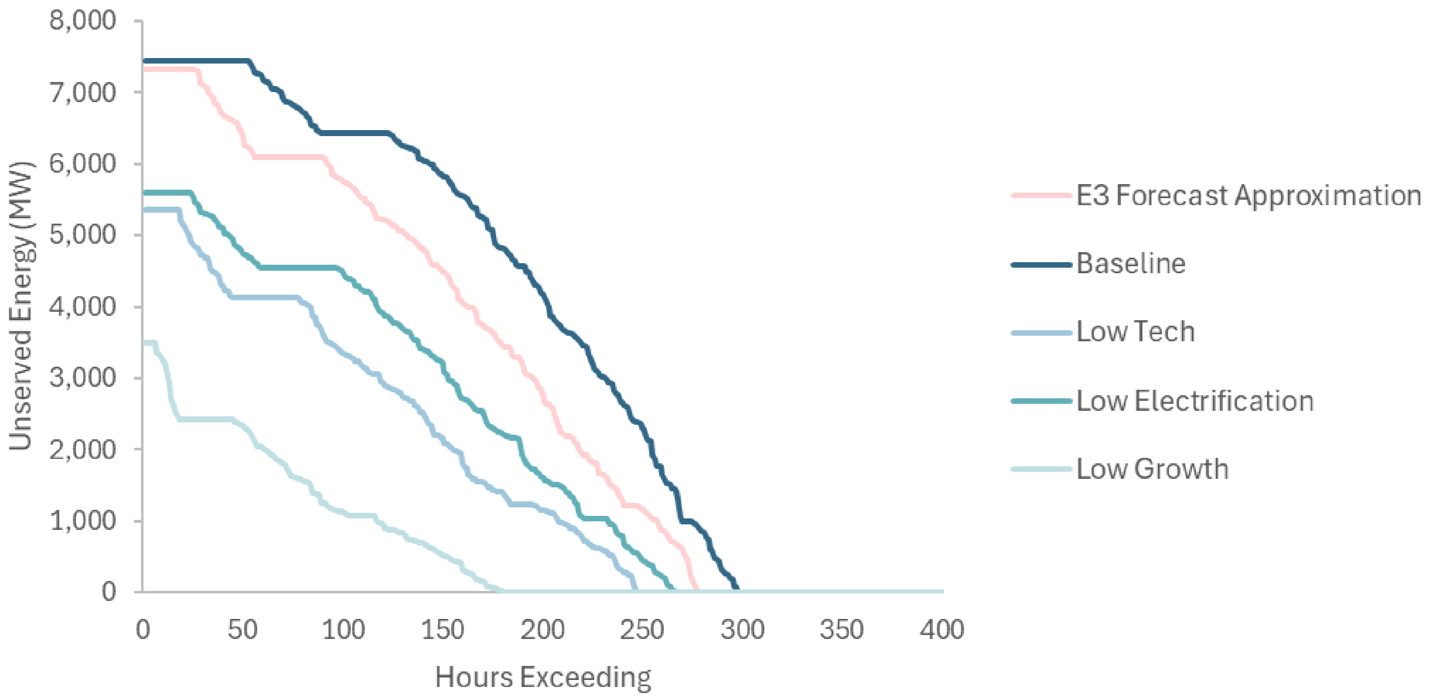
Our findings generally corroborate E3's high level problem statement

Across all load scenarios, unserved energy is observed in large quantities and in several hours if there are no resource additions through 2030, similar to E3's findings

Notes:

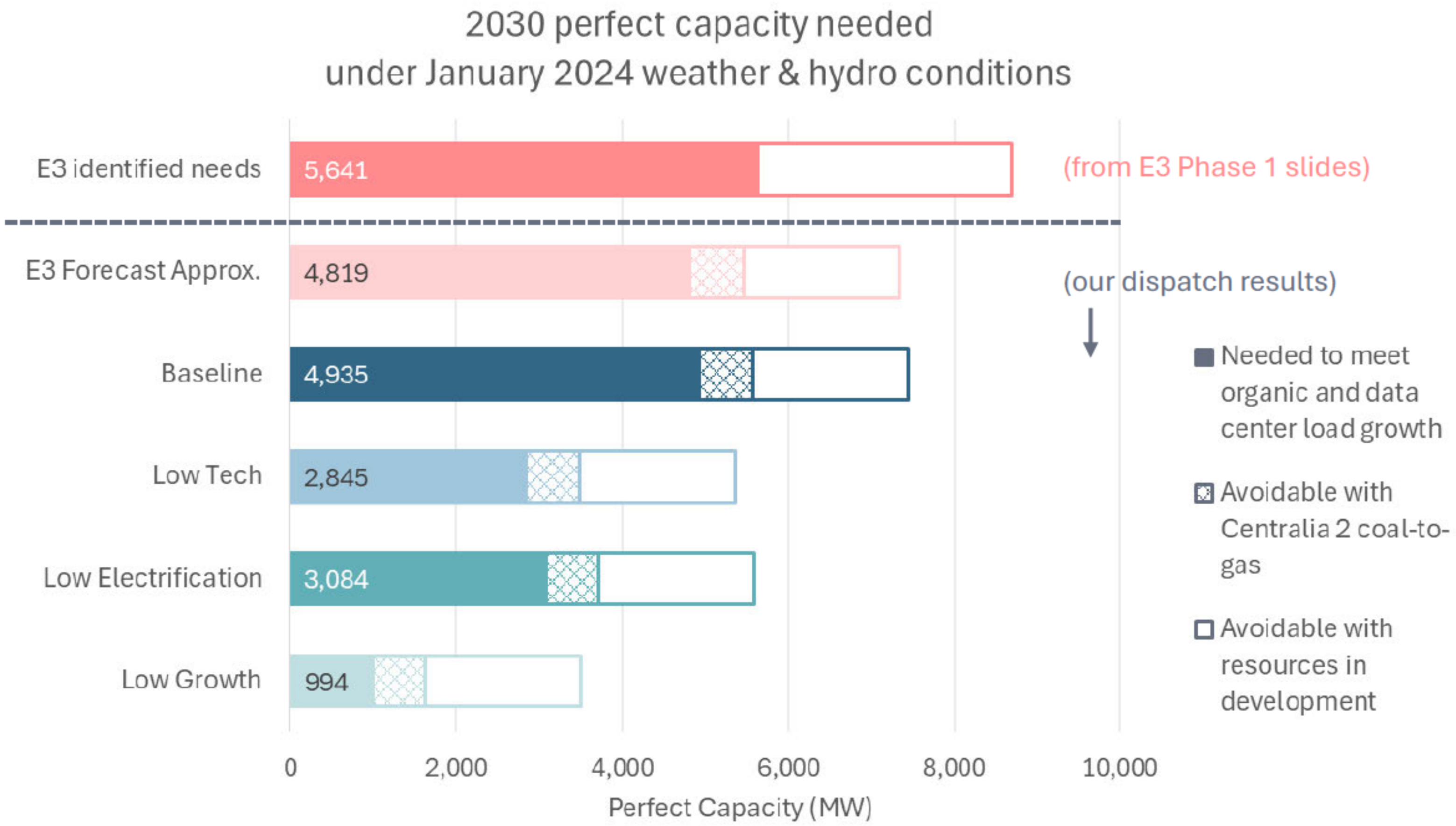
- These results are based on "operational" runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

Simulated unserved energy (sorted from high to low) with no resource additions, before Centralia 2 coal-to-gas conversion



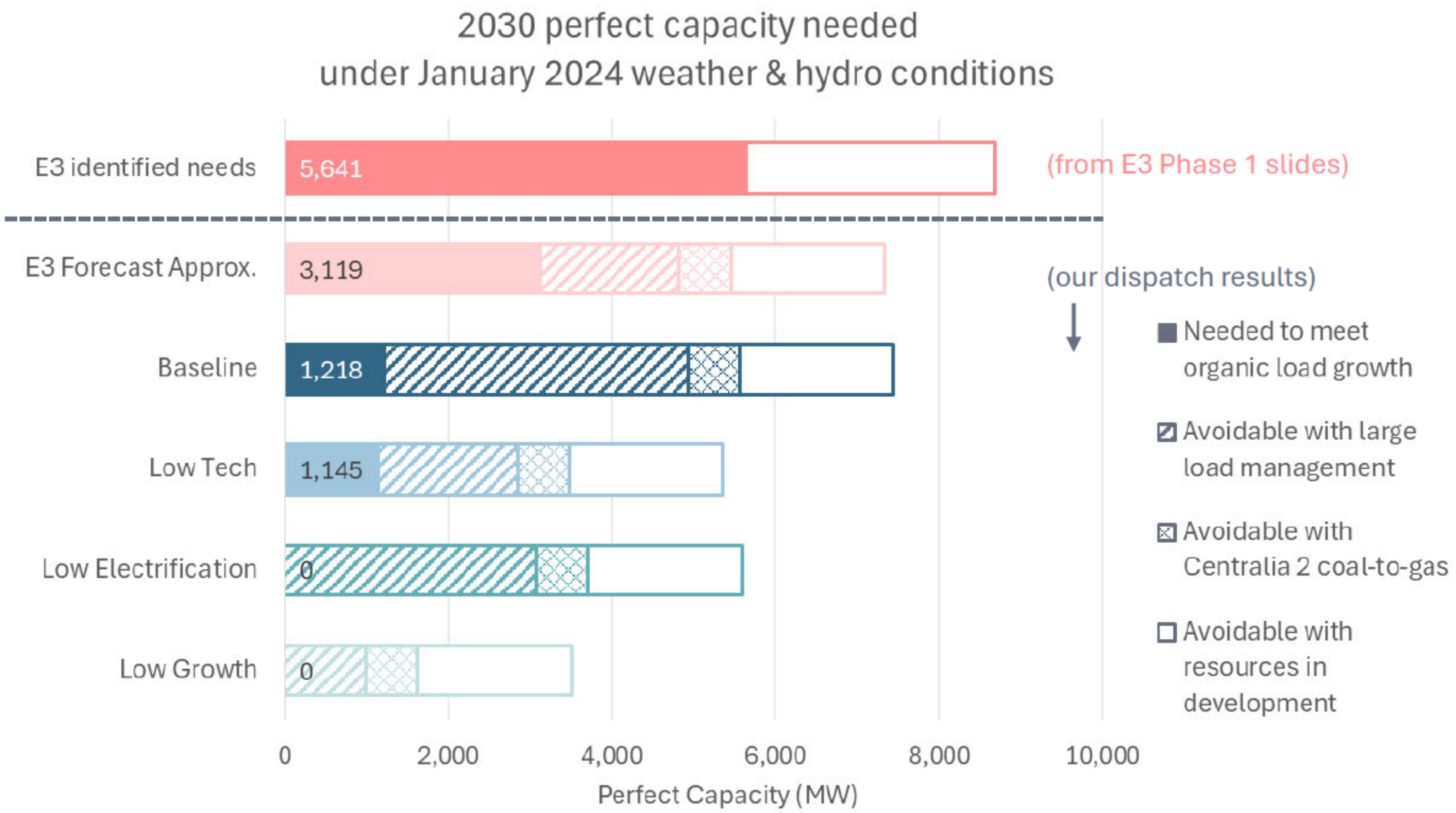
How sensitive are 2030 resource adequacy needs to future load growth?

- No analysis can predict the future and resource needs in 2030 remain highly uncertain, due both to new large loads and electrification trends
- After accounting for resources already under construction or with regulatory approvals in place as of December 2024 according to EIA 860 (“in development”) and coal-to-gas conversion of Centralia 2, estimated remaining 2030 needs range from 1 GW to 5 GW of “perfect capacity” across load scenarios



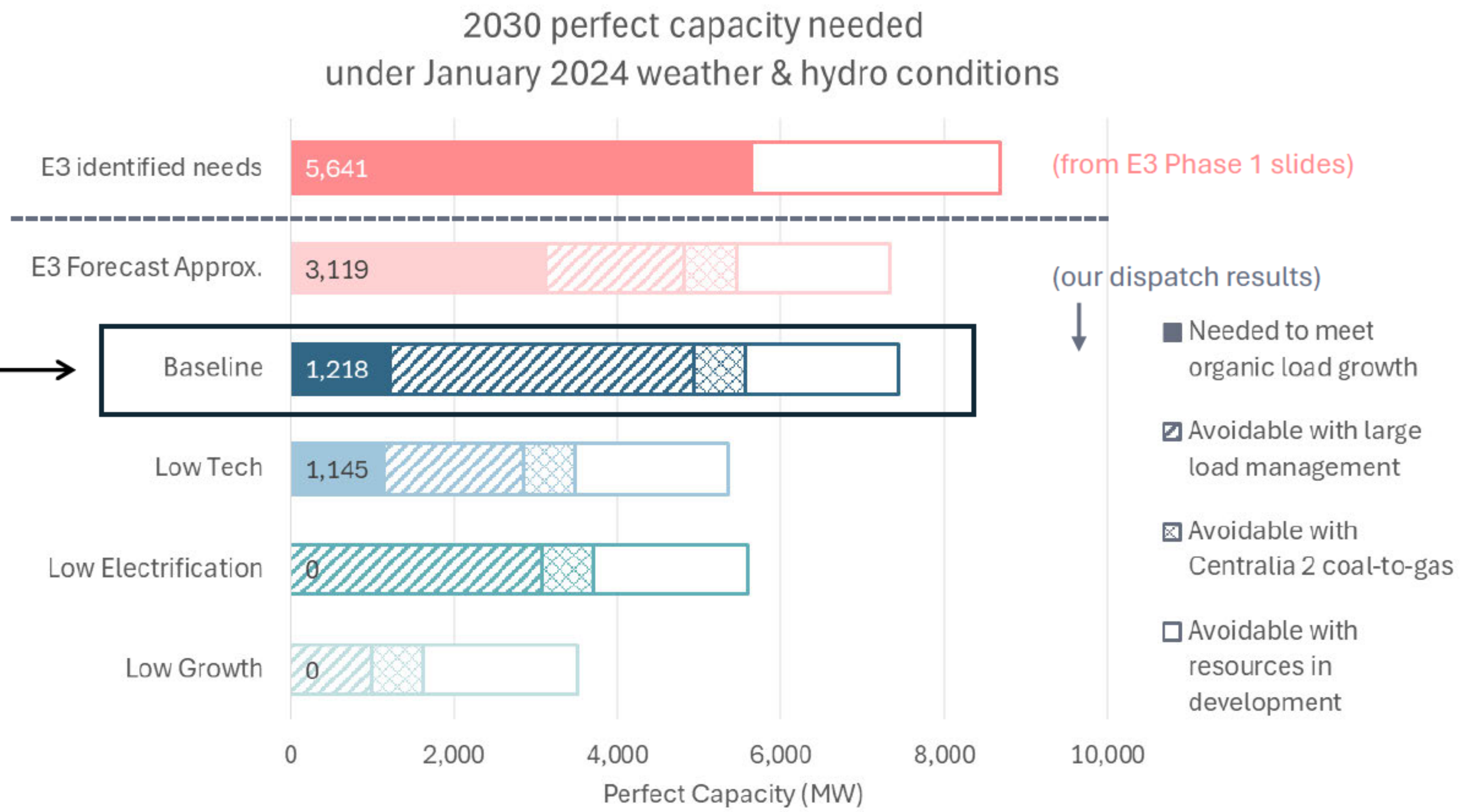
"Connect and manage" for large loads and resource adequacy

- Large loads, which remain highly uncertain in terms of both whether they will materialize and how long they will persist on the grid, are a key driver of near-term needs
- If large loads are interconnected before adequate supply is secured, emergency large load curtailment during extreme weather could mitigate risks to other customers, similar to new requirements in Texas
- If large loads can be managed during extreme weather events, estimated remaining 2030 needs range from 0 GW to 3 GW, depending on organic load growth (including electrification)



"Connect and manage" for large loads and resource adequacy in the Baseline Scenario

Let's dig further into the Baseline Load Scenario



Supply shortages from the customer's perspective

If no additional resources are secured beyond those already in development, what does the shortage under the Baseline Scenario look like from the customer perspective during this event?

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	**19 hrs**	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Near-term opportunity:

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages
  - Could be paired with bring-your-own generation strategies
  - Could enable more rapid interconnection

*Resources in development were either under construction or had final regulatory approvals in place as of December 2024

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

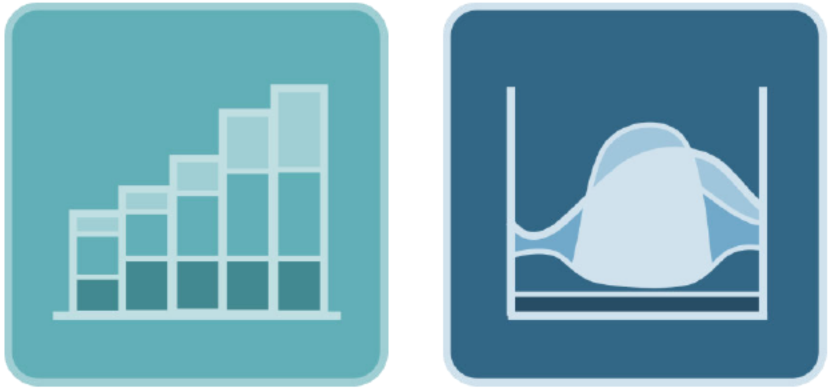
Addressing supply shortages with new clean resources

- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
  A. To meet organic load growth; and
  B. To meet all load growth, including data center demand
- Findings are broadly indicative
  - Resource costs were high level and imprecise (i.e., these are not optimal selections)
  - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

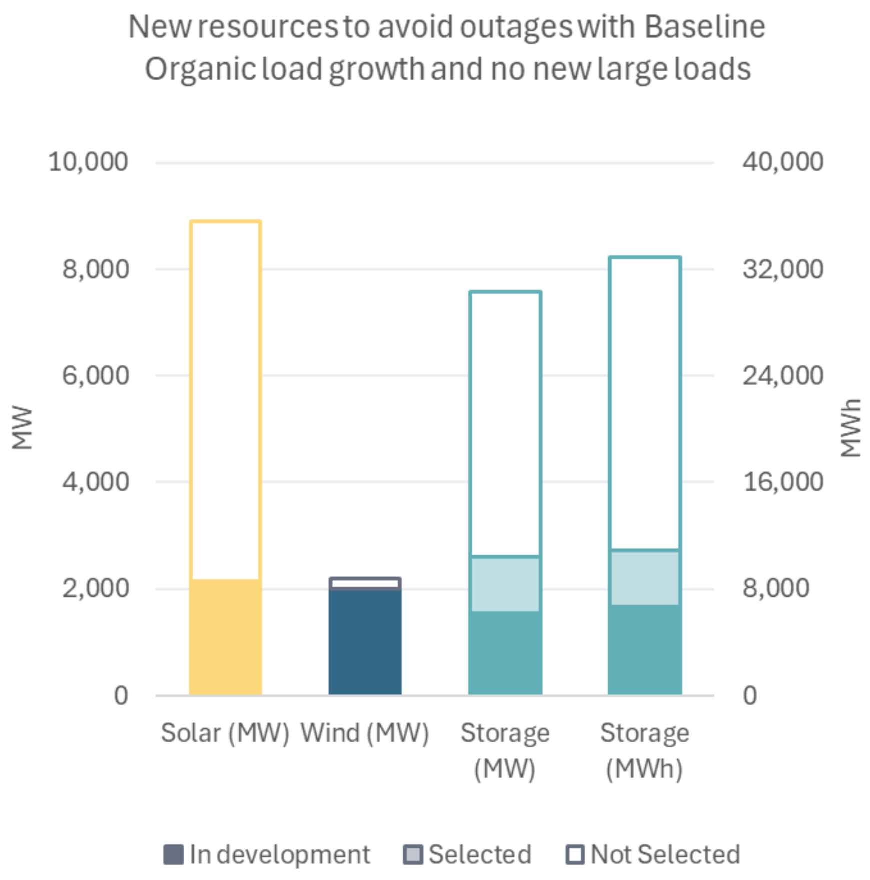
Blended production cost/capacity expansion mode

GridPath

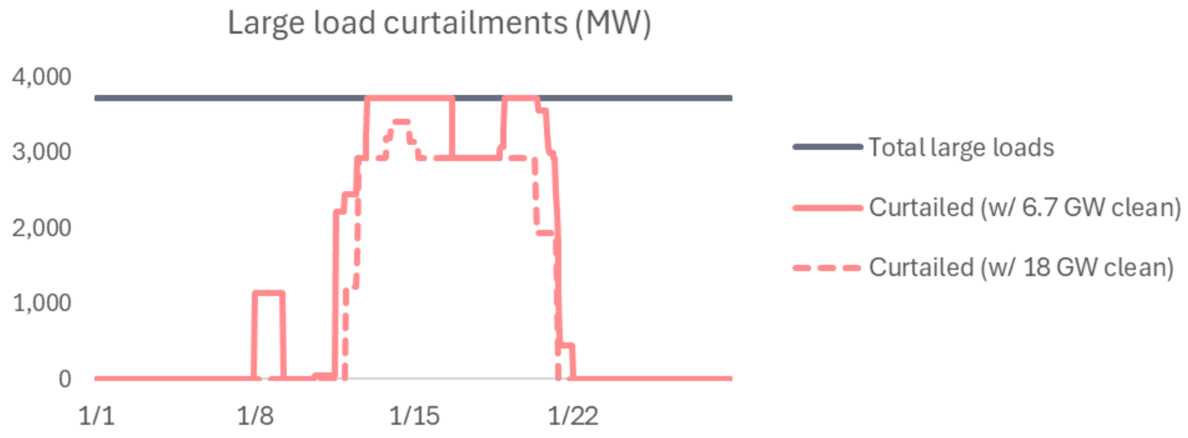
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



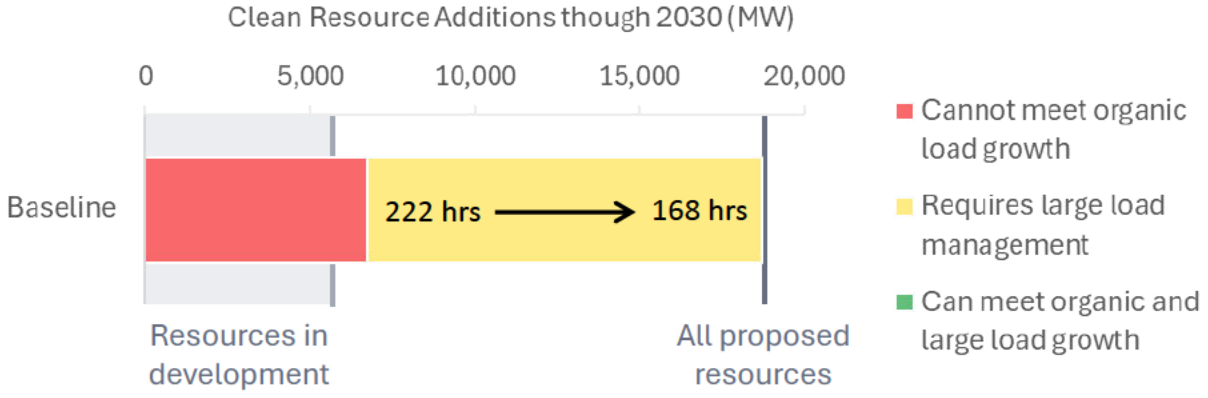
Clean resource additions and large load management in the Baseline scenario



- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event

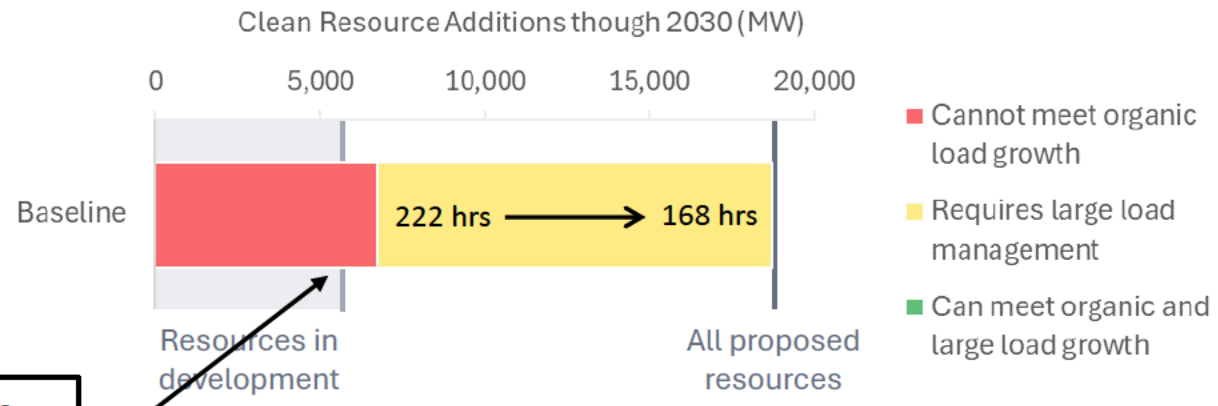


Clean resource additions and large load management across the scenarios



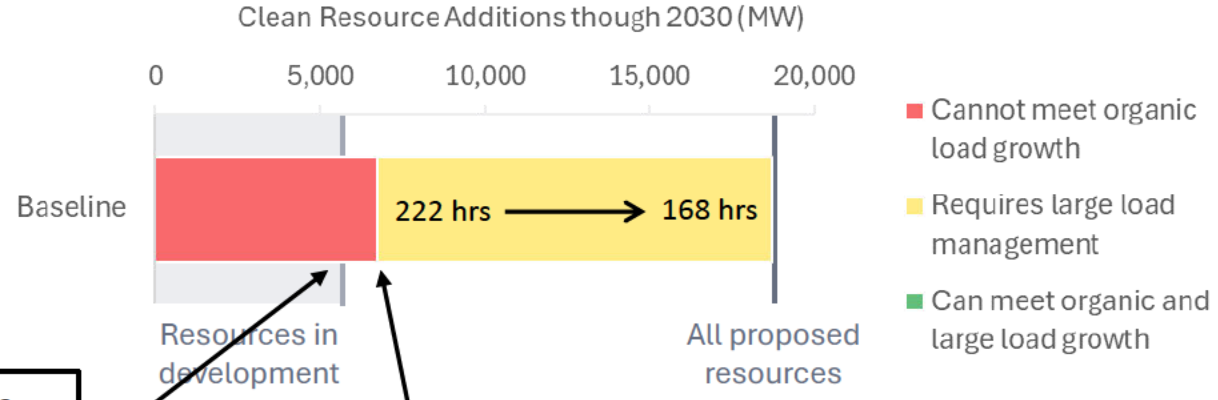
To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

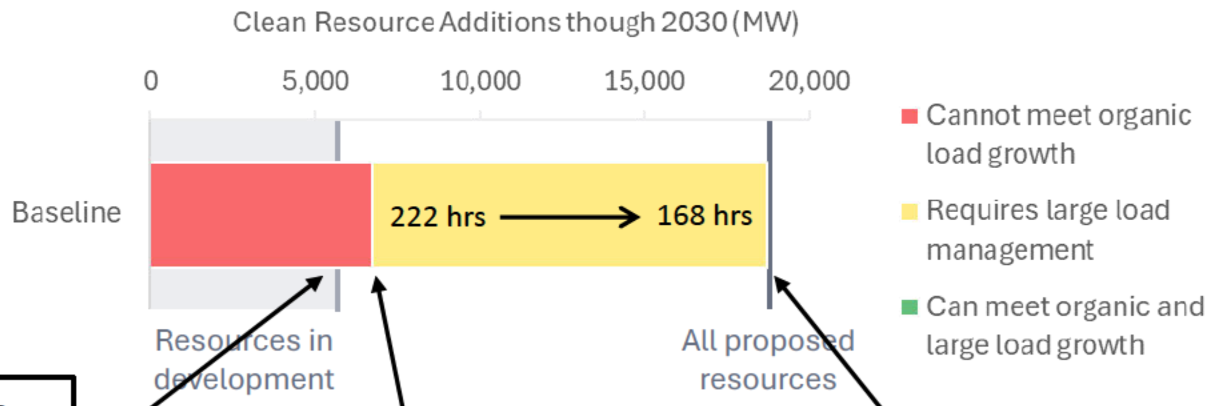
Clean resource additions and large load management across the scenarios



1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

Clean resource additions and large load management across the scenarios

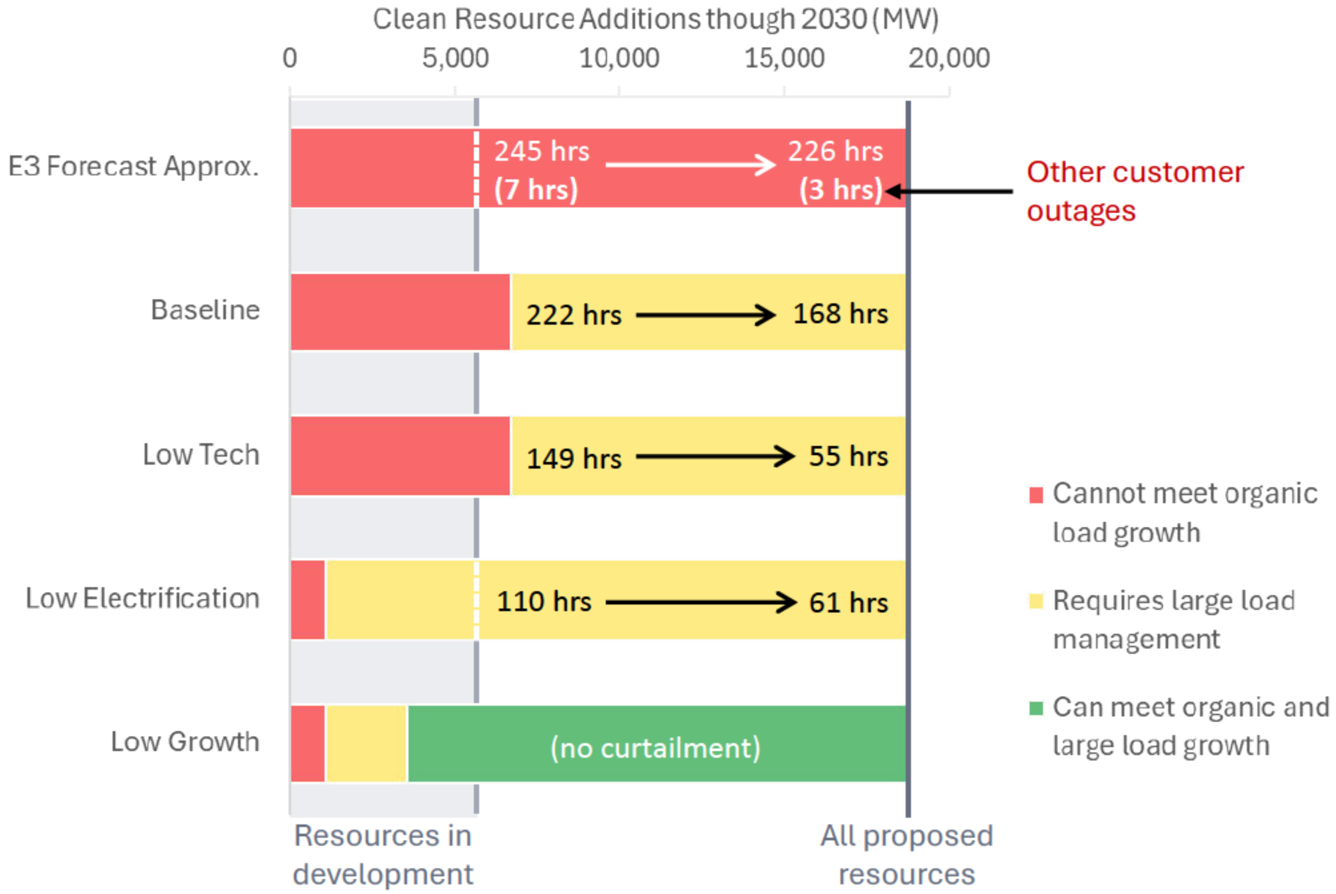


1. Clean resources in development (5.7 GW) <u>are not</u> adequate to meet organic load growth during the event

2. Resources in development plus additional clean resources (6.7 GW total) <u>are</u> adequate to meet organic load growth, but require 222 hrs of large load curtailment

3. With all proposed clean resources (19 GW), large load curtailment persists (168 hrs)

Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios

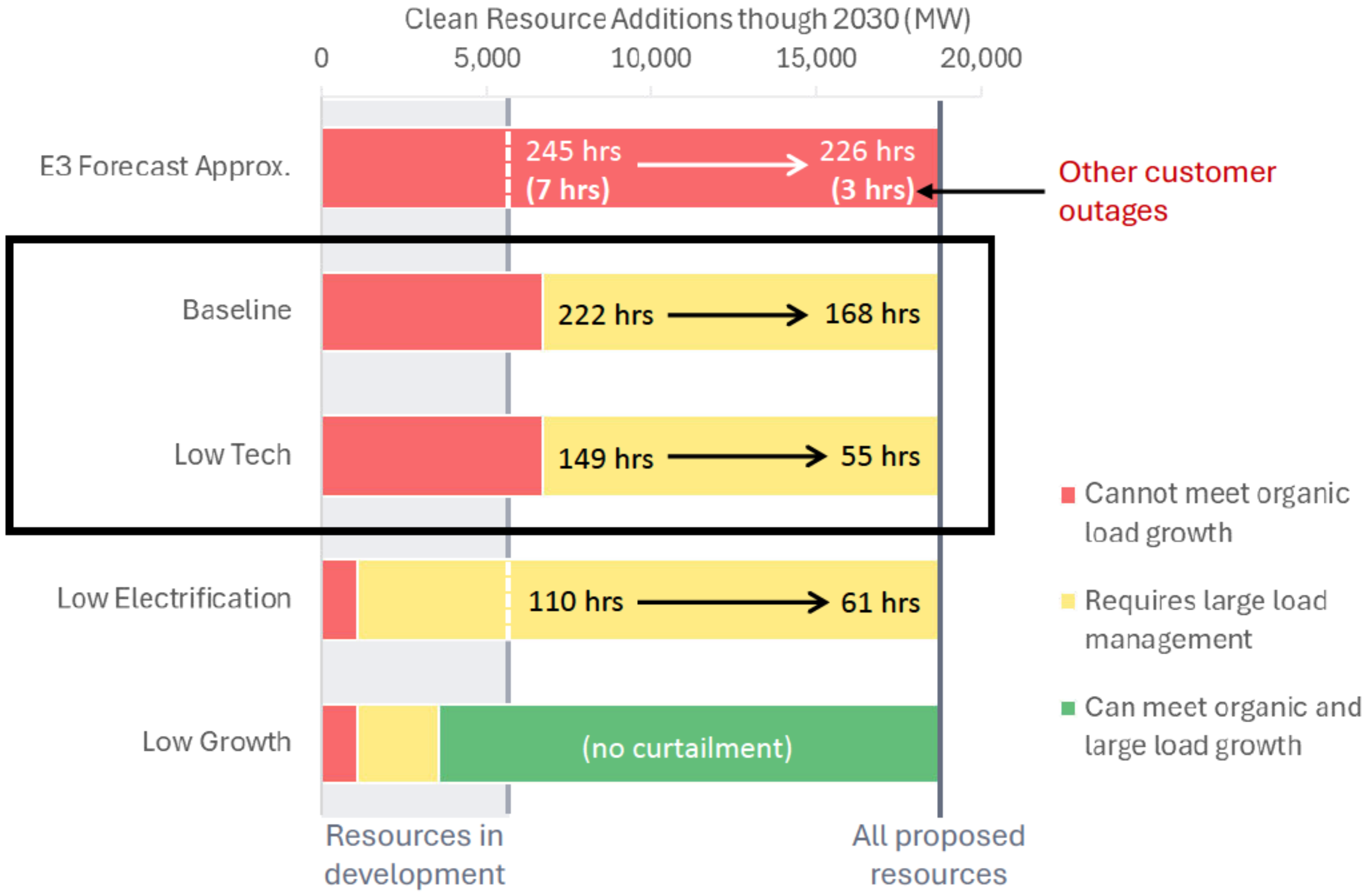
In scenarios without accelerated electrification (Low Electrification and Low Growth):

- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)

Clean resource additions and large load management across the scenarios

In scenarios that project 1.4% annual organic load growth (Baseline and Low Tech):

- Clean resources in development plus a relatively small amount of incremental resources are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 55 hrs to 222 hrs)



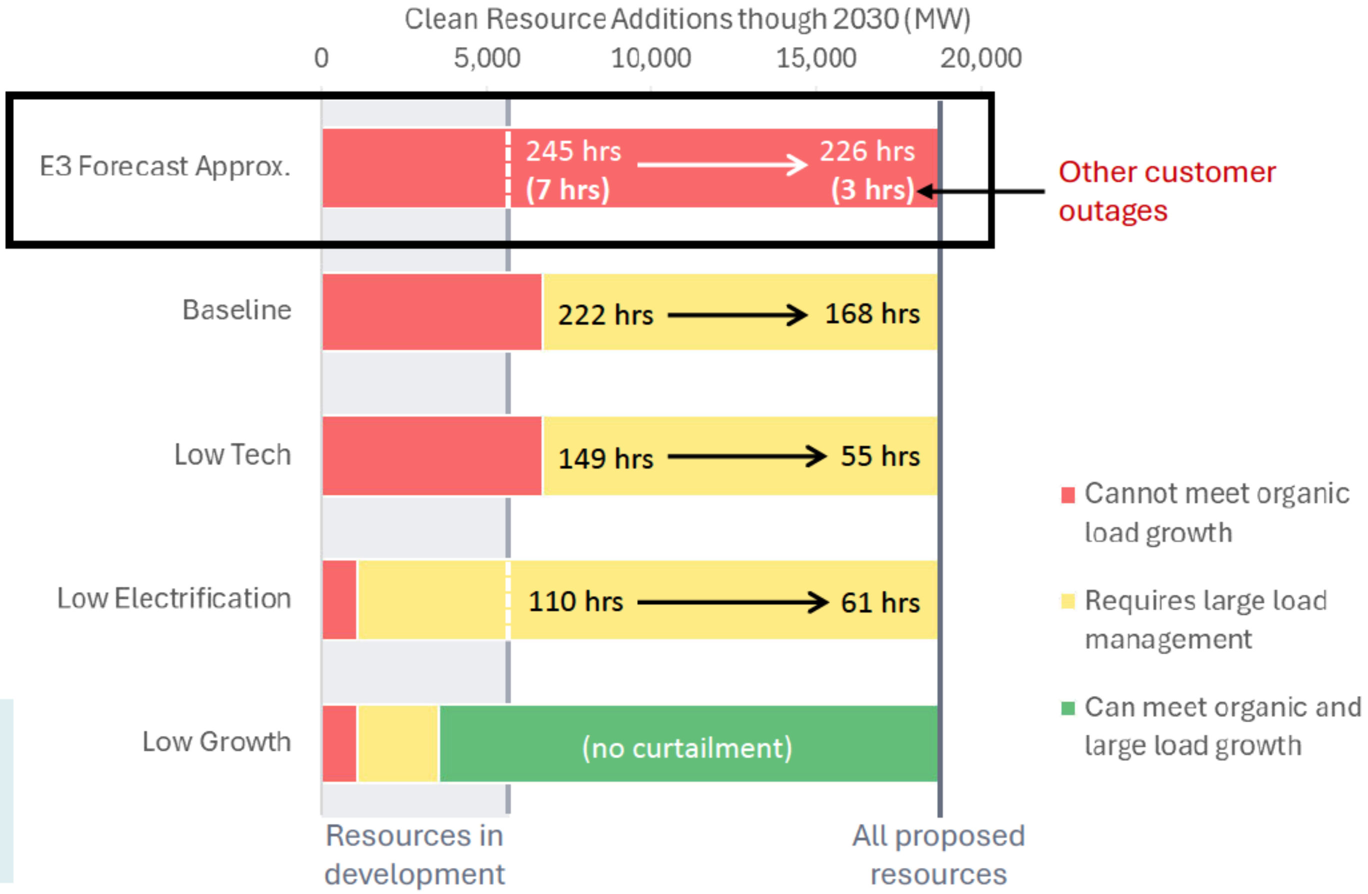
Clean resource additions and large load management across the scenarios

Under E3's load growth scenario, which includes more rapid electrification and relatively low data center demand, <u>the region is in a real bind!</u>

- Resource needs to meet organic growth exceed the quantity of proposed clean projects (19 GW)
- Large load curtailments exceed 100 hrs and other customers may experience rolling brown outs even with large load curtailments unless additional resources can come online
- New gas has been discussed as a solution to this challenge, but the gas system was constrained during the January 2024 event as well

Near-term opportunity:

➢ Study impacts of regional natural gas system constraints on regional electricity reliability

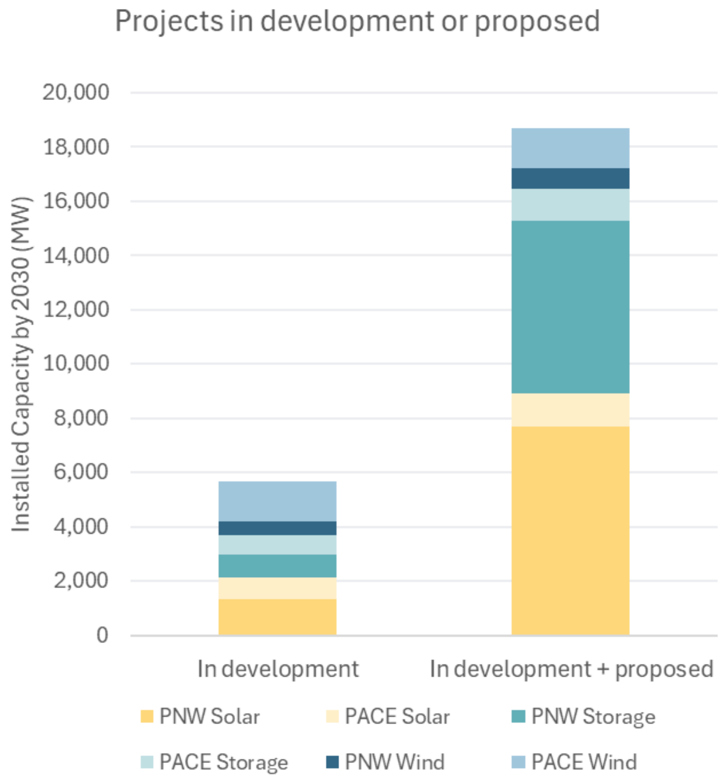


Winter portfolio ELCCs of new clean resources

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

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
Total	18,675	4,348	23%

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

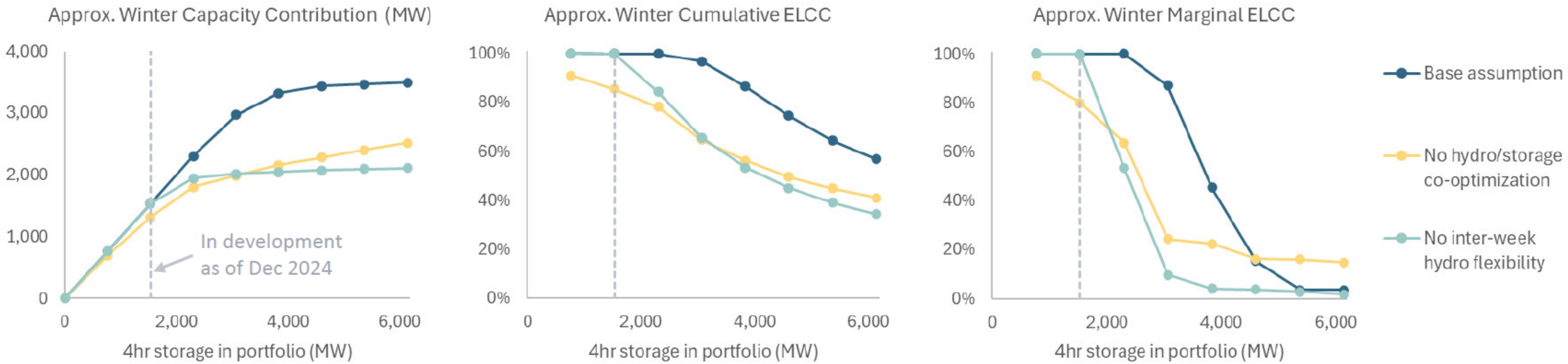


Near-term opportunity:

➢ Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities

Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
    1. Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
    2. Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



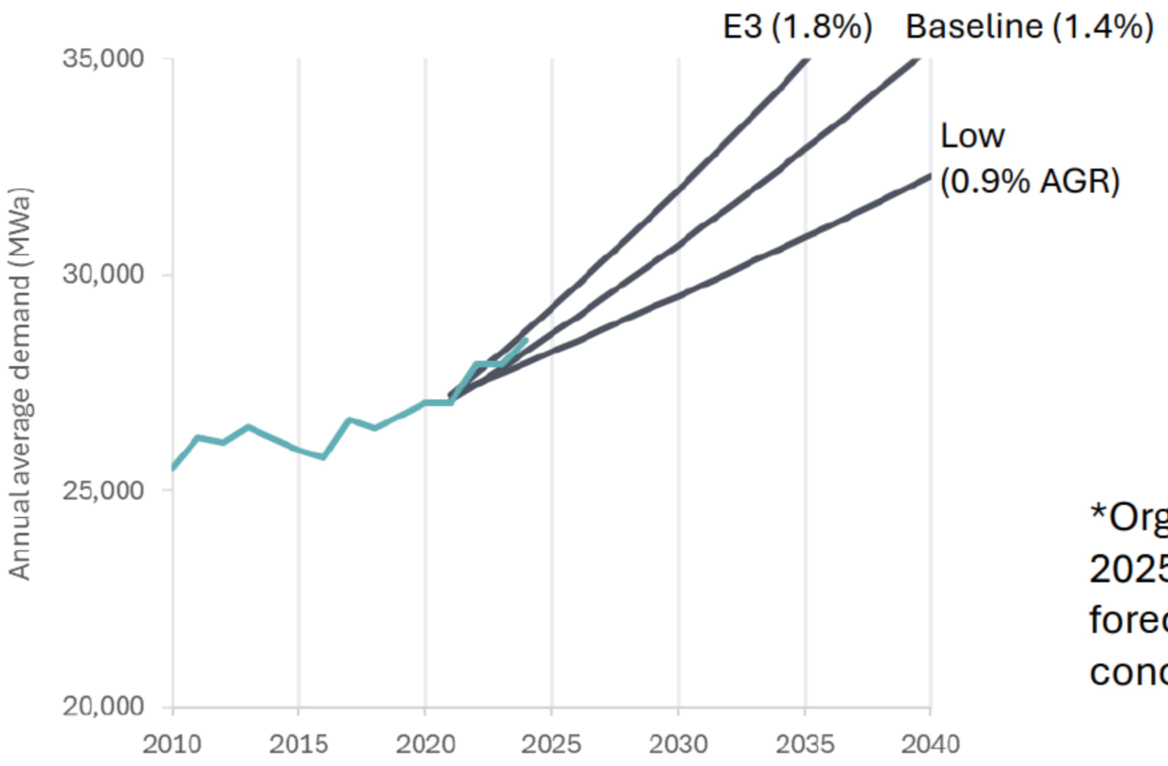
Notes:
- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
  - With no incremental resources
  - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
  - With emergency large load curtailment
- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

The need for dispatchable or baseload solutions is not a question of if, but when

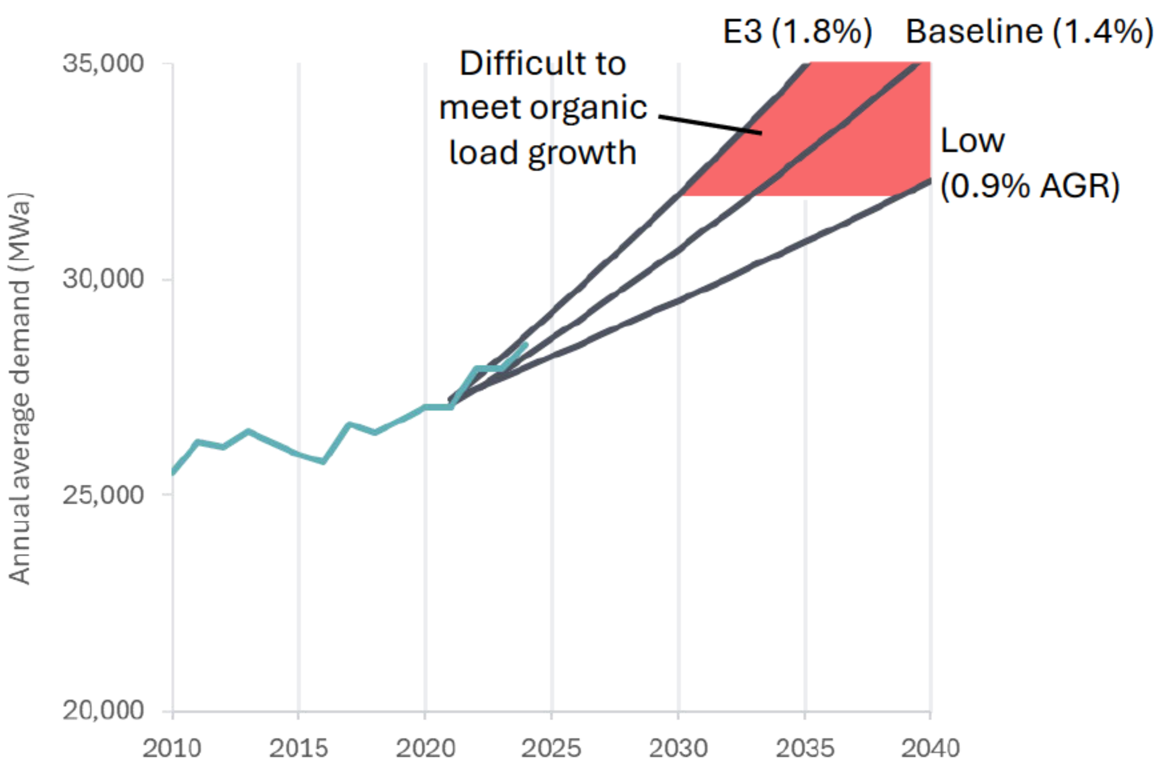
Extrapolated* organic load growth trajectories



*Organic load growth trajectories estimated by applying the 2025-2030 average annual organic load growth rate from each forecast to 2031-2040. This exercise is indicative and conceptual and may not align with actual load forecasts.

The need for dispatchable or baseload solutions is not a question of if, but when

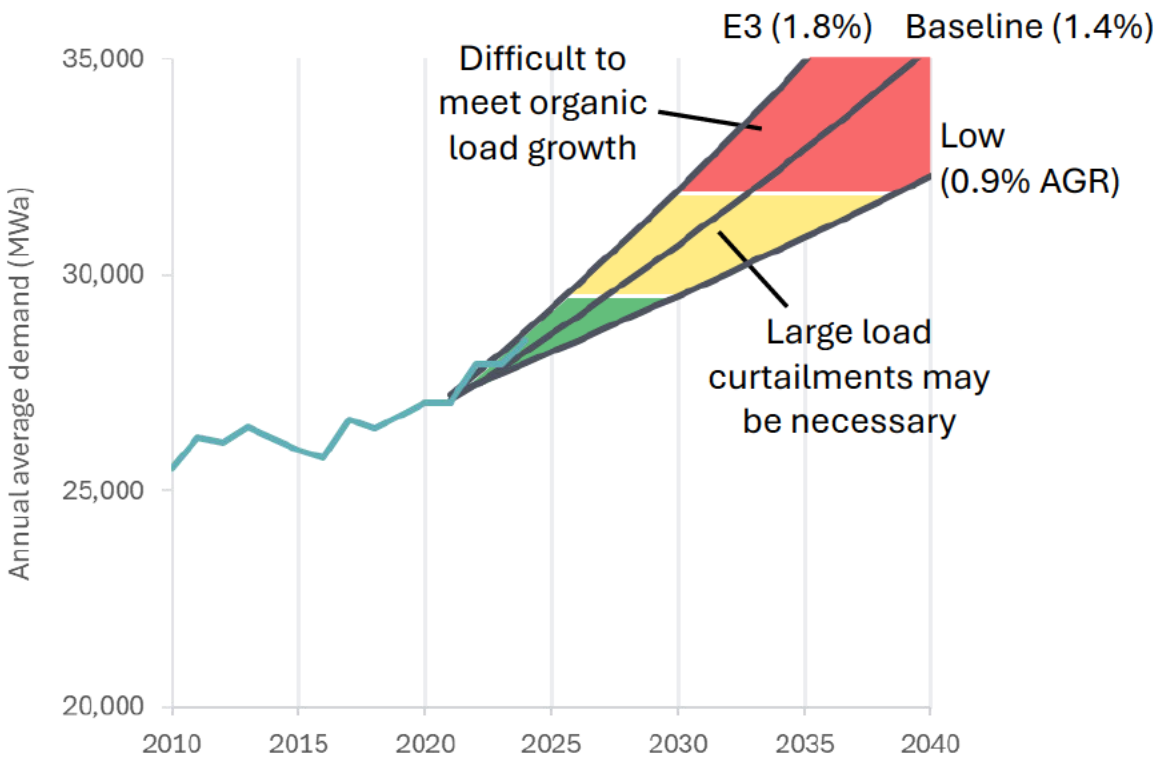
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

The need for dispatchable or baseload solutions is not a question of if, but when

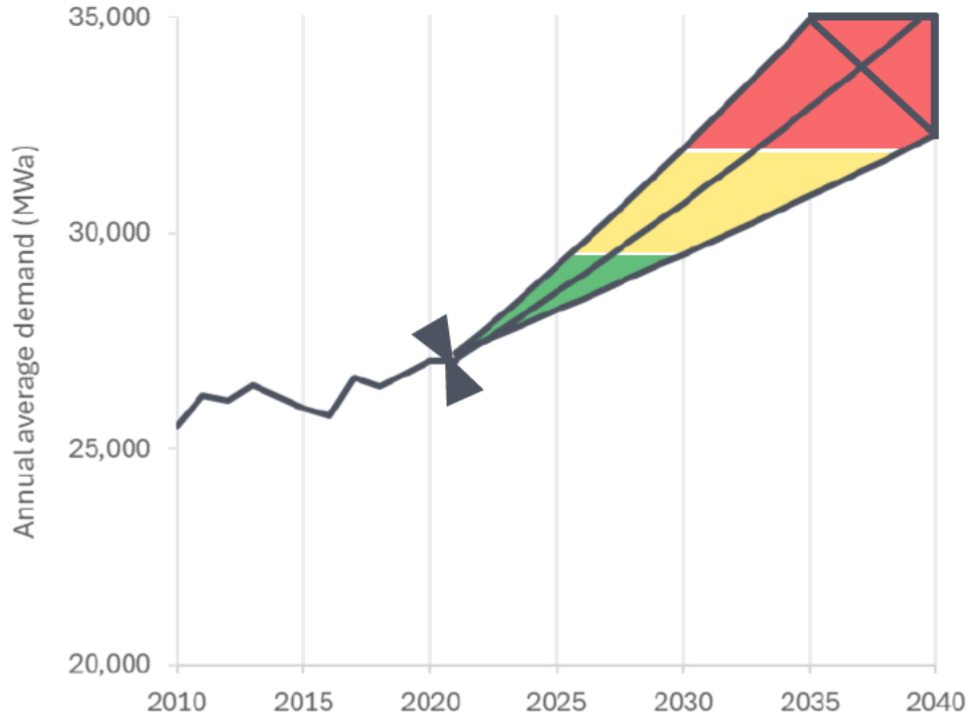
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
  - E3 Forecast: By 2030
  - Extrapolated Baseline Forecast: Roughly early 2030s
  - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

"A kite only flies when it's tethered"

-Victor Robert Lee



We can't control the wind (or the economy), but we have some tethers on the demand side that could buy the region some time

Near-term opportunities:

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)


Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Near-term opportunities identified to support regional RA

Policy

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages

Planning & Development

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)
- Prioritize transmission studies and upgrades that support increased South-to-North flows into the Pacific Northwest during the winter
- Schedule coal-to-gas conversion activities to minimize winter downtimes
- Study impacts of natural gas system constraints on electricity reliability

Operations

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest
- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits


Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

Thank you!

For more information, contact:

elaine@sylvan.energy

SYLVAN ENERGY ANALYTICS

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 1-25:
MISO LOLE Presentation

LOLE 101: Probabilistic Analyses

LOLE 101 Training

5/8/2018

Loss of Load Expectation (LOLE) 101 Sections

- LOLE Background & History
- LOLE Study Connections to other MISO Processes
- Generating Availability Data System (GADS) Overview
- LOLE Modeling
- Strategic Energy Risk Valuation Model (SERVM)
- LOLE Results Walkthrough
- Takeaways
- Reference Materials

Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand

Loss of Load Probability (LOLP) is the probability in a given hour	Sum of the Daily Peak LOLP values is an expectation (LOLE)	Sum of all LOLP values is called Loss of Load Hours (LOLH)

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, "perfect storm". The study of low probability, high impact events.

1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:

<1-day in 10-years

=

NERC Standard BAL-502-RF-03

- Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

Common Terminology Misconceptions

- 1 day in 10 years LOLE ≠ 24 hours in 10 years LOLH
  - Example: 2 hours of firm load shed = 2 loss of load hours and 1 day of loss of load
  - By definition 1 day/ 10 years LOLE ≤ 24 hours / 10 years LOLH

- Cannot calculate Loss of Energy Expectation (LOEE) from LOLH without running complete analysis

LOLE Connections to Various MISO Processes

LOLE

- **Planning Reserve Margin (PRM) Study**
  - **Resource Adequacy**
    - Tariff Module E-1
    - Planning Resource Action
  - **Planning Studies**
    - MTEP Futures Development
    - MTEP Study
- **Assessments**
  - NERC Assessments
  - MISO Informational Forums

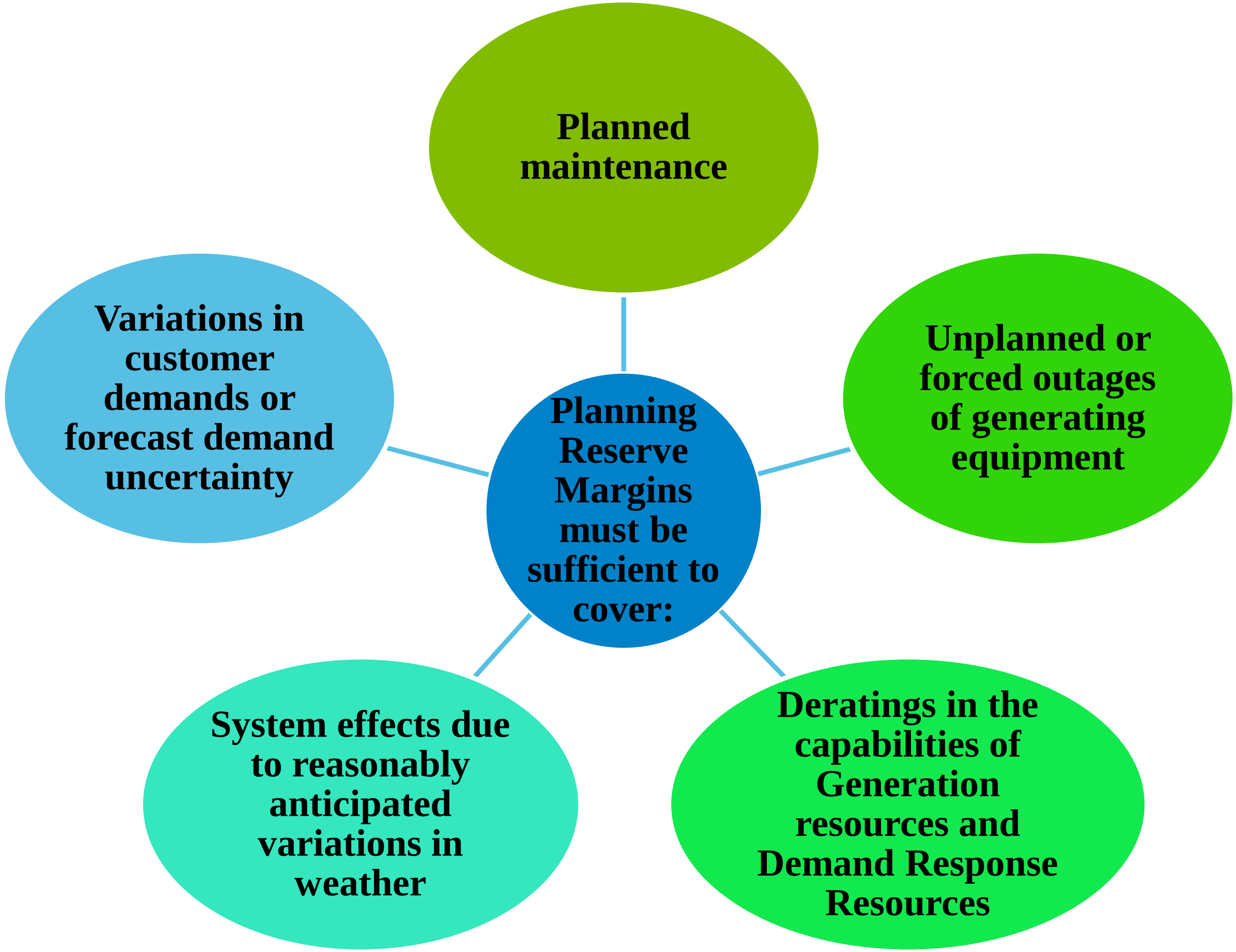
Resource Adequacy Overview

- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin

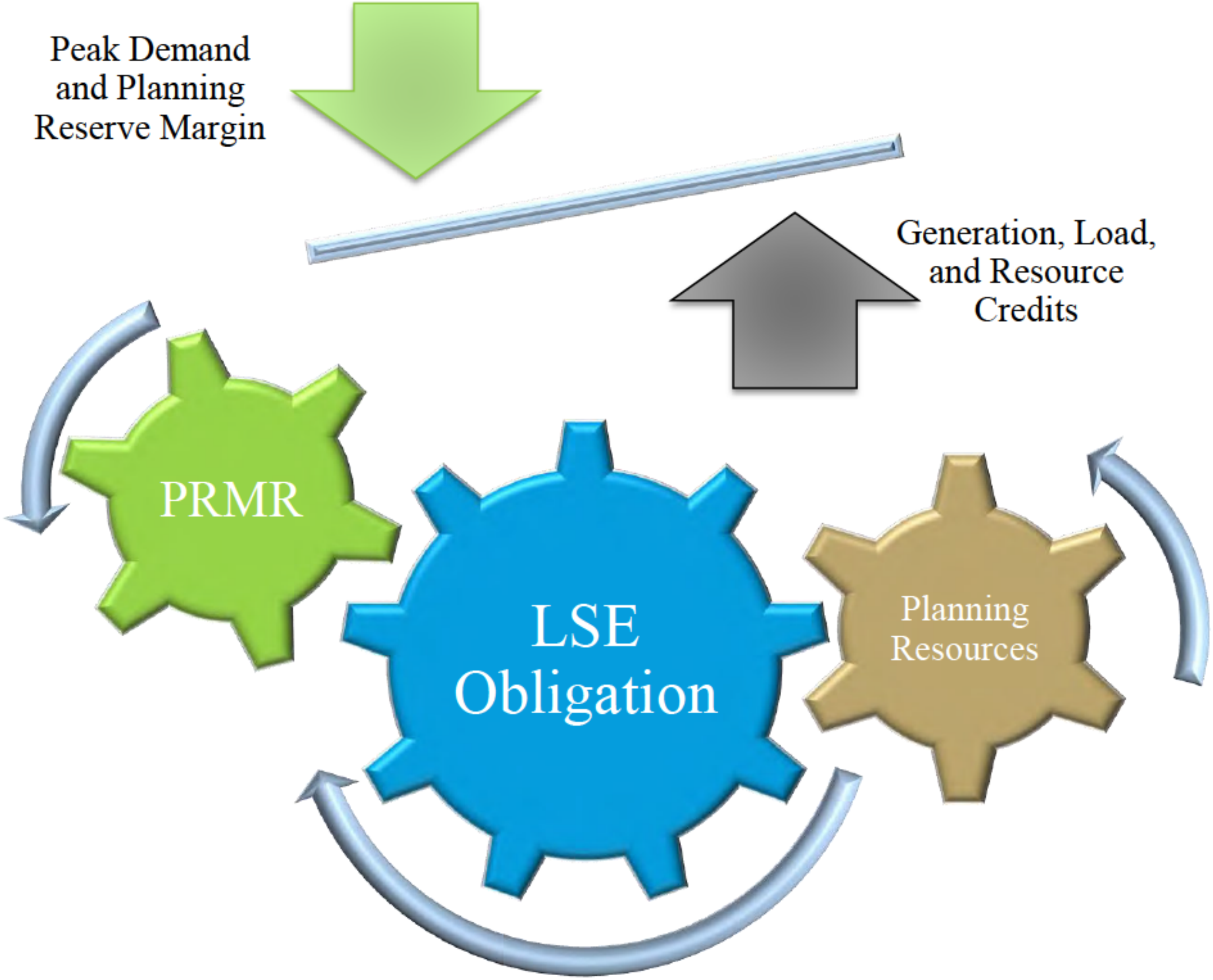
Margins necessary to promote Resource Adequacy need to be assessed on:

Longer-term planning basis	Near-term operational basis
Focus of MISO's RA Construct is on the longer-term planning margins used to provide sufficient resources to reliably serve load on a forward-looking basis	Resources dedicated to meet Demand have an obligation to be available to meet real-time customer demand and contingencies

Planning Reserve Margins (PRMs)



Overview of MISO Resource Adequacy Requirements



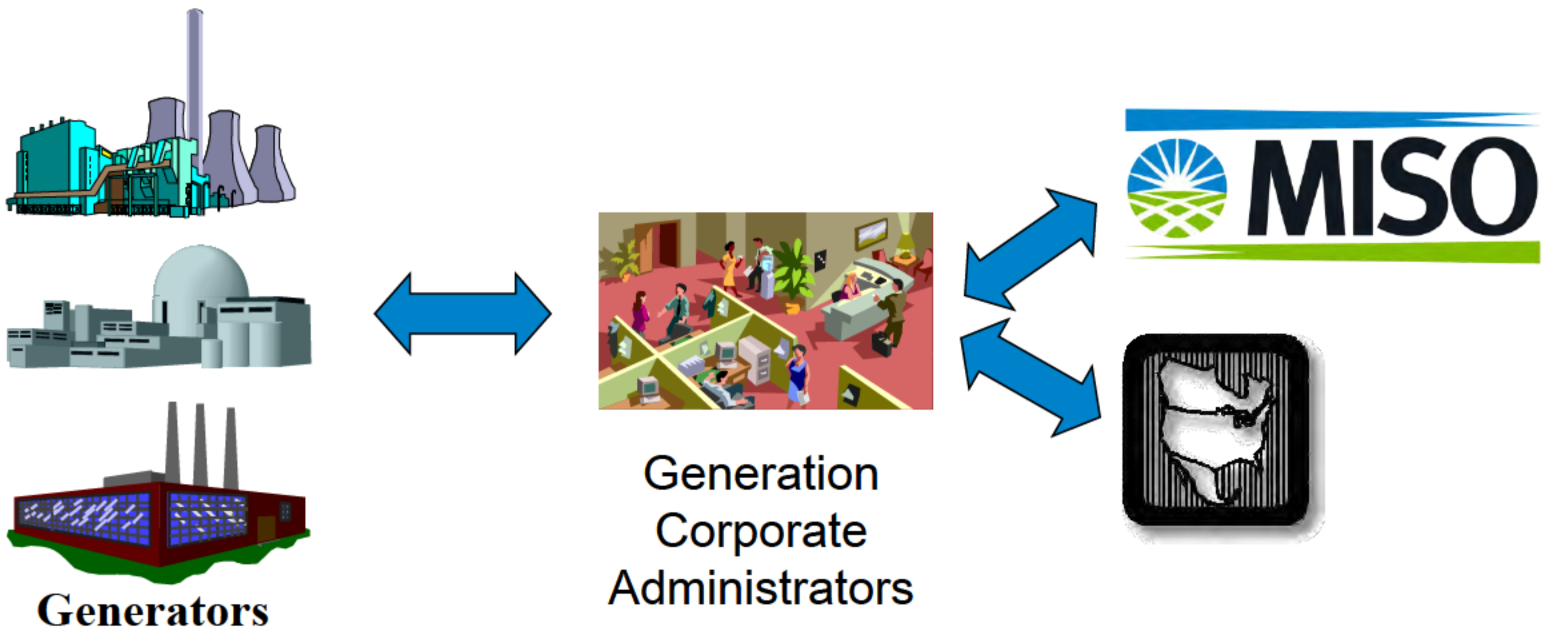
PowerGADS – Performance & Reliability System

For capacity planning and reliability study purposes,

all generating facilities declared as capacity resources in the MISO market

are required to submit GADS event and performance data

to determine the value of the facility as an unforced capacity resource



GADS Data Requirements…

- Generation Resources
- External Resources
- Demand Response Resources backed by behind the meter generation
- or Behind the Meter Generation (BTMG)

Greater than or equal to 10 MW, based on Generation Verification Test Capacity (GVTC)

- Must submit generator availability data (including, but not limited to, NERC GADS) into PowerGADS through the Market Portal

Less than 10 MW, based on (GVTC), that begin reporting generator availability data

- Must continue to report such information

GADS Data Requirements…

- Quarterly Submittal of Data
  - Stakeholders are expected to submit data on a quarterly basis
  - Quarterly GADS data must be received by the last day of the month following the operating quarter
  - Quarterly GADS data must be Level 2 Validated by the last day of the month following the operating quarter

GADS Data Requirements…

- A unit will receive 100% EFORd if it fails to submit GADS data and successfully Level 2 Validate

- Assigning 100% EFORd will impact a unit's unforced capacity calculation
  - $UCAP = GVTC \ * (1 - EFORd)$

Three Types of Data are to be Collected…

Event Data

- Each time a unit has a change in operating status or capability, an *event* is recorded
- From these event reports a unit's operational history can be reconstructed

Generation Performance Data

- A unit's actual generation, hours of operations, and operational characteristics

Fuel Performance Data (optional)

- A unit's actual fuel consumption and fuel quality data

PowerGADS – Event Data

Event data – to be collected:

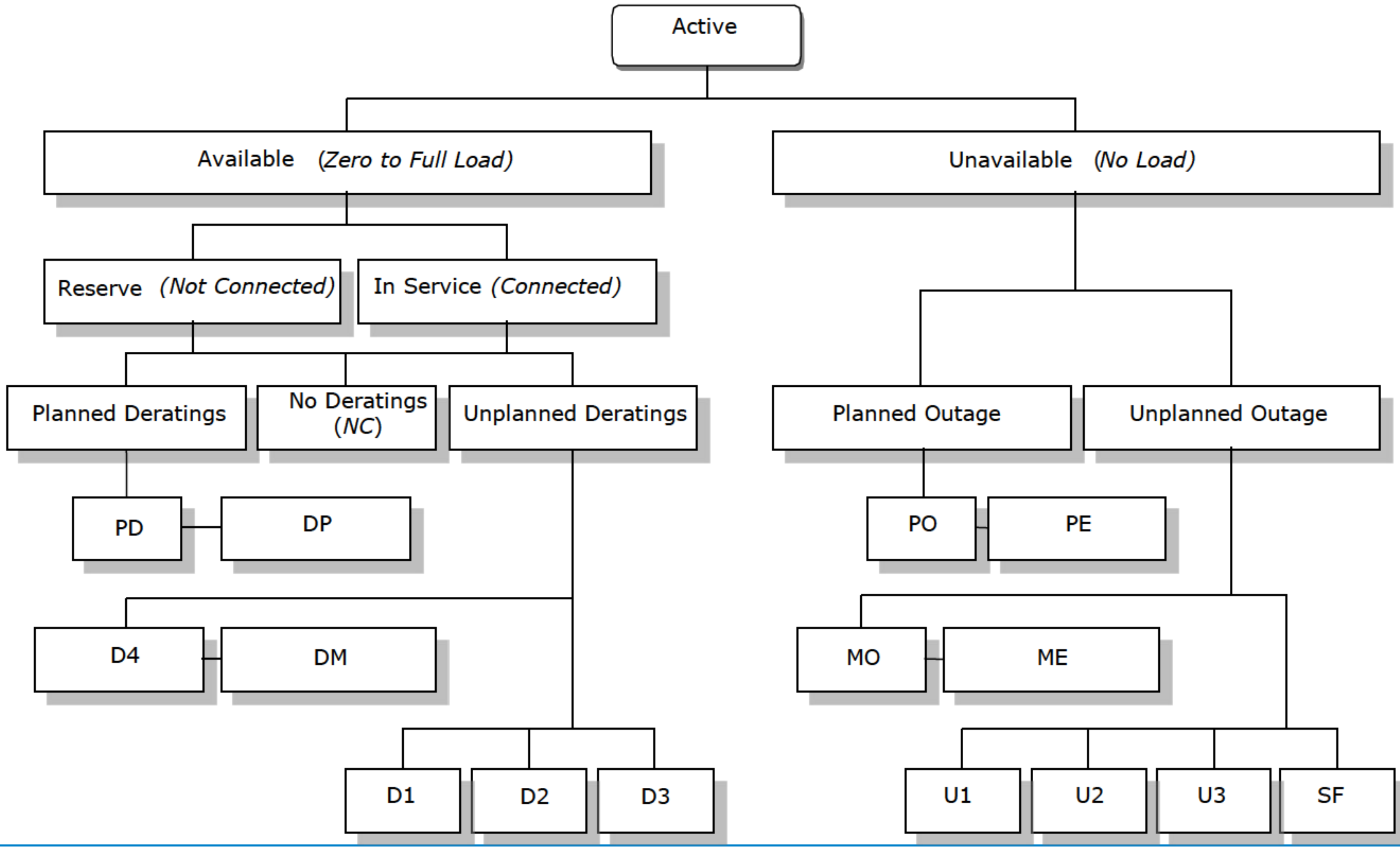
- Event Number
- Event Type
- Start of Event
- End of Event (Can be blank if event is ongoing)
- Net Available Capacity
- Primary Cause Code
- Additional Cause Code (Optional)
- Event Contribution Code
  - describes impact or contribution that this cause or component had on the event
- Verbal Description (Optional)
- Failure Code (Optional)

PowerGADS – Performance Data

Performance data – to be collected:

- Net Maximum Capacity
- Net Dependable Capacity
- Net Actual Generation
- Typical Unit Loading Code
- Loading Verbal Description
  (If Typical Unit Loading Code is 6)
- Attempted Unit Starts
- Actual Unit Starts
- Unit Service Hours
- Reserve Shutdown Hours
- Pumping Hours
- Synchronous Condensing Hours

PowerGADS – Event Types



LOLE Model Inputs Include:

Generation Resources

- Operating Parameters
- Unit Forced Outage Rates
- Planned Maintenance Schedules & Rates
- Dispatch Limits for Demand Response

Study System

- Zone & Pool definition
- External Tie Limits
- External System Model

Load

- Demand and Energy Forecast
- Load Shape/Profile
- Load Uncertainty

LOLE Model Inputs

Source of LOLE Model Input Data

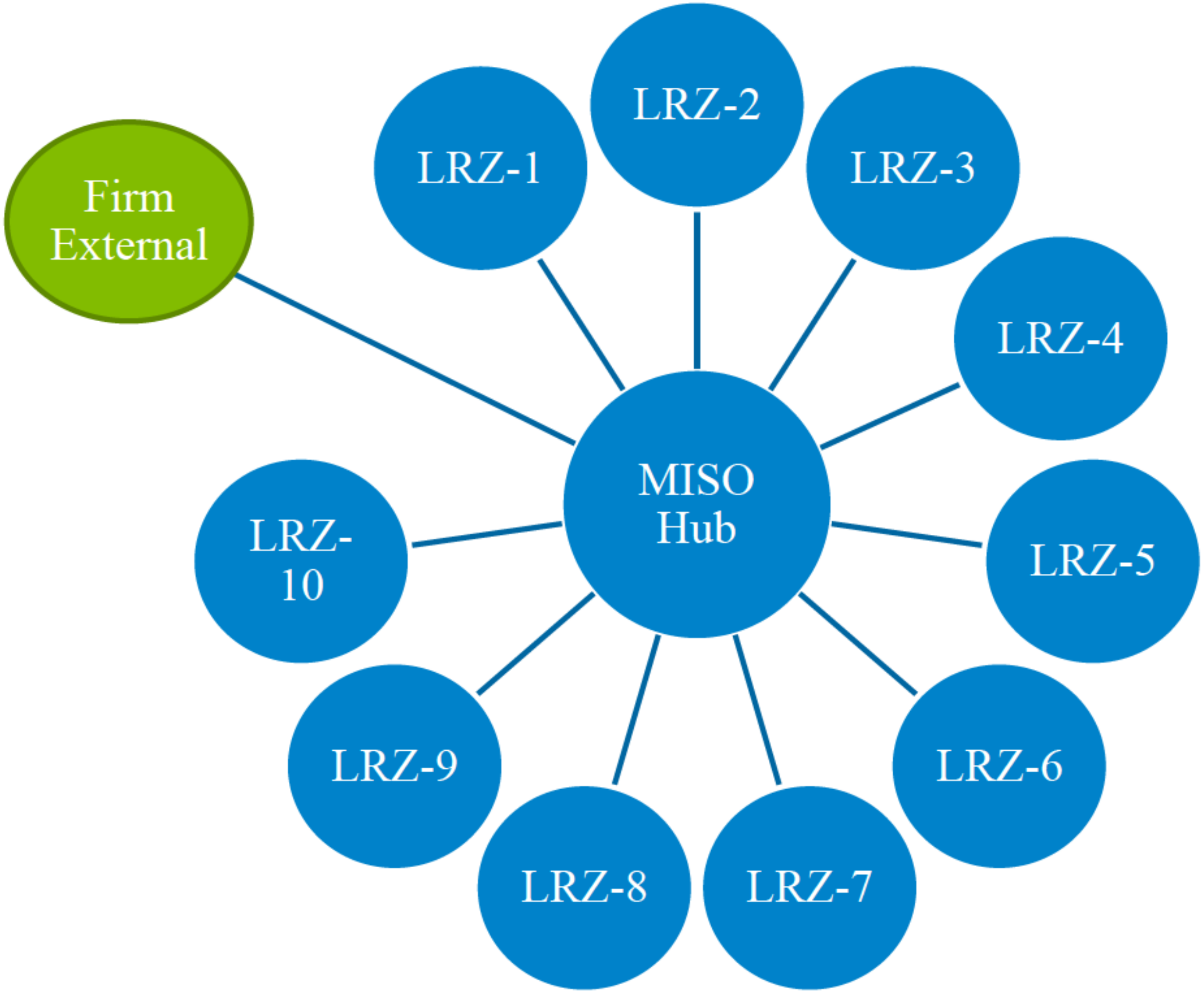
Generation Resources

- Generating Availability Data System (GADS)
  - Unit performance statistics used to calculate forced outage rates
  - Data is uploaded into the MISO system one month after end of each quarter
- Generation Verification Test Capacity (GVTC)
  - Units need to demonstrate maximum output level

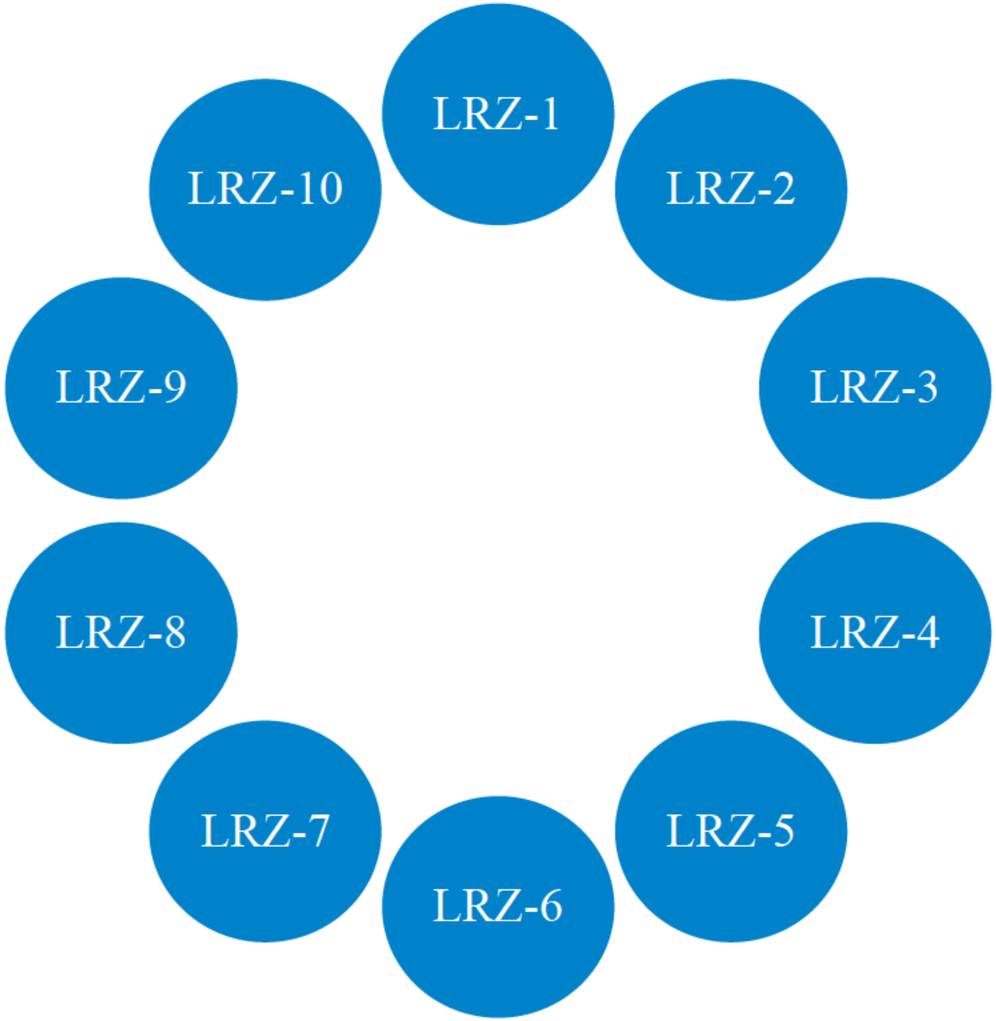
Load

- Load training using historical load and weather data
- Monthly Peak Demand, MISO Coincident Demand and Energy Forecast are uploaded by Load Serving Entities (LSEs) into the Module-E Capacity Tracking (MECT) Tool (deadline Nov. 1st)
- MISO reviews Forecast and Finalize review by March

MISO System LOLE Model



Local Resource Zone LOLE Model



MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980’s

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database

Analytical vs. Monte Carlo approach to analysis

- Analytical methods work well for small systems and represent a system using mathematical model (A direct mathematical solution)

- Monte Carlo methods simulate the actual process and repeat simulation until convergence criteria is met

- For complex systems, a Monte Carlo “brute force” approach is more appropriate

Types of Monte Carlo Analysis

- Non-Sequential Monte Carlo Simulation
  - Each hour is independent of every other hour
  - Inability to model time-correlated issues
  - Inability to calculate frequency and duration indices
- Sequential Monte Carlo Simulation
  - Steps through time chronologically
  - Ability to model time correlated issues and calculate frequency and duration indices
  - Requires more detailed system data

Utilized SERVM Characteristics

- Multi Area Model
- Multiple Weather Years (supports up to 50 years)
- Detailed DR Representation
- Granular LOLE Calculations

Additional SERVM Characteristics

- Renewable Generation Modeling
- Transportation model to represent multiple neighbors and interconnections
- Full Economic Dispatch of Resources Allowing for Dispatch Constraints on Resources
- Alternative Dispatch During Reliability Events
- Operating Reserves Modeled Based on NERC Guidelines
- Economic Calculations
- Scarcity Pricing Algorithms
- Production Costing Ability

Utilized SERVM Modeling Components

- Weather Years
  - Multiple load shapes
- Economic Load Forecast Error (LFE)
- Unit Outage Modeling
- Energy Limited Resource Modeling
  - Demand Side Options

Additional SERVM Modeling Components

- Weather Years
  - Thermal Capacity/Hydro
- Energy Limited Resource Modeling
  - Hydro and Pump Storage
  - Renewable resources (.i.e. Wind & Solar)
- Scarcity Pricing, Neighbor Modeling, and Transmission Modeling
- Emergency Operating Procedures

Importance of Load Modeling in LOLE Analysis

- Loss of Load Expectation analysis is largely driven by two factors
  - Generation Uncertainty
  - Load Uncertainty
- Accurately capturing uncertainty is crucial to LOLE analysis
- Load Uncertainty
  - Load Shape
  - Weather Uncertainty
  - Economic Uncertainty

Load Modeling Framework

- Use historic weather years to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape

- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty

- Utilize Neural-Net software to “train” data

Load Training Process

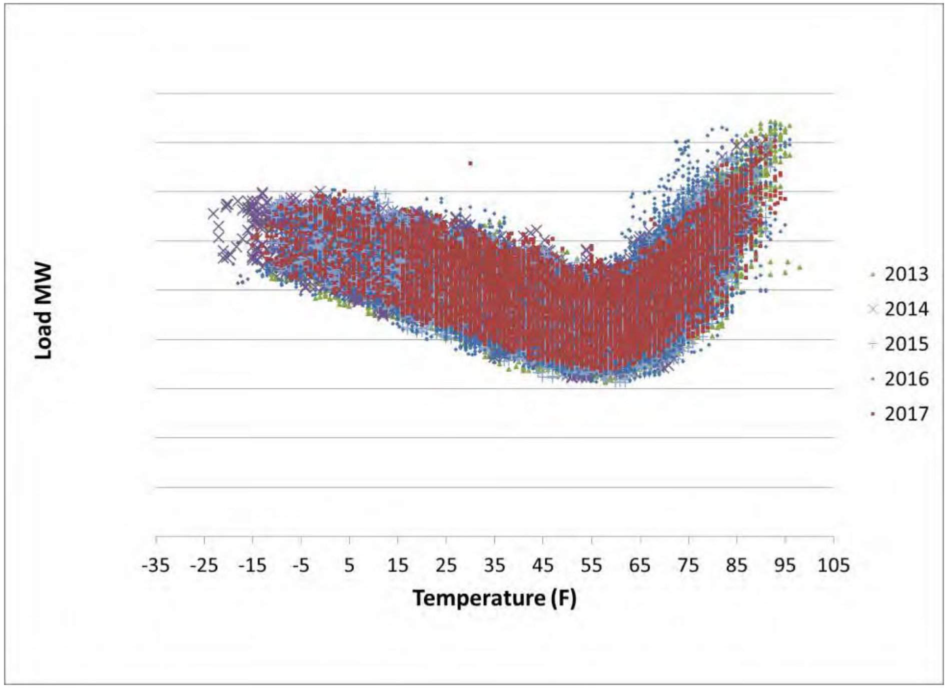
- Historical load and weather data formatting
- 5-year load growth adjustment
- Neural-net training
- Neural-net predicting
- Extreme temperature adjustment
- Load forecast adjustment

Data Sources for Load Training

- Historical real-time settlement load data
  - Source: MISO
  - 2013 to 2017
- Historical real-time LMR performance
  - Source: MISO
  - Voluntary and MISO deployments
  - 2015-2017
- Historical weather data
  - Source: NOAA
  - 1989 to 2017
- LSE load forecasts
  - Source: LSE submittals to MECT

Historical Load and Weather Formatting

- 5 years of hourly load and temperature (2013-2017)
- Weather data (2013-2017)
  - Month
  - Temperature
  - Time of Day
  - Day of Week
  - 24 hour ago Temperature
  - 48 hour ago Temperature
- Holidays are set to Sunday
  - New Year's Day
  - Memorial Day
  - Independence Day
  - Labor Day, Thanksgiving Day & Christmas Day



5-Year Load Growth Adjustment

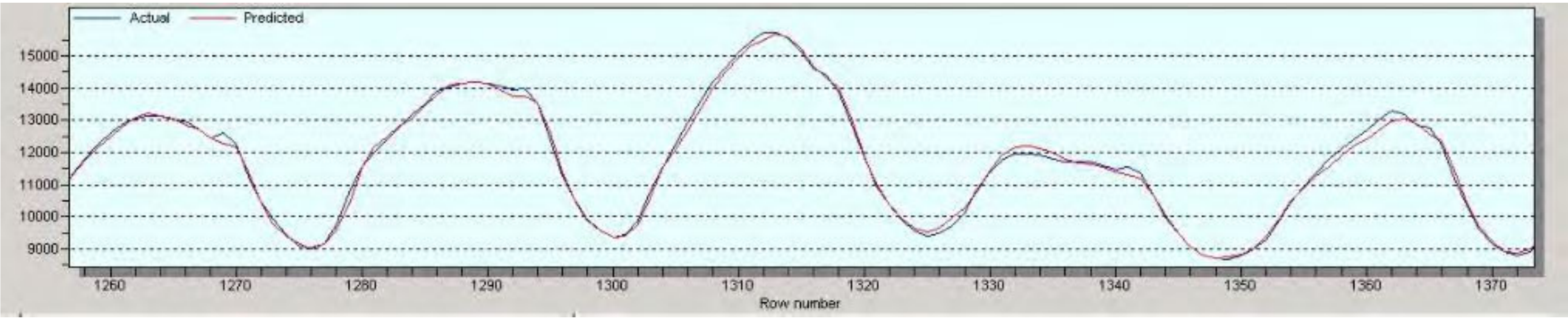
- 5 years of load data should not include load growth due to economics
- Load normalized to consistent economics
- Adjustment calculated based off high temperature load analysis i.e. 90 degrees and above

NeuroShell Predictor Software

- Ward Systems Group Software
- Used for pattern recognition of multi-variable problems
- Makes predictions based off of established neural-net functional relationships
- Software tutorial can be found at the link below:
  - http://www.wardsystems.com/predictortutorial.asp
- Load Training Input Variables:
  - Month
  - Day of week
  - Time of day
  - Previous hour load
  - Temperature
  - 24 hour ago temperature
  - 48 hour ago temperature
- Load Training Output Variables:
  - Actual Load

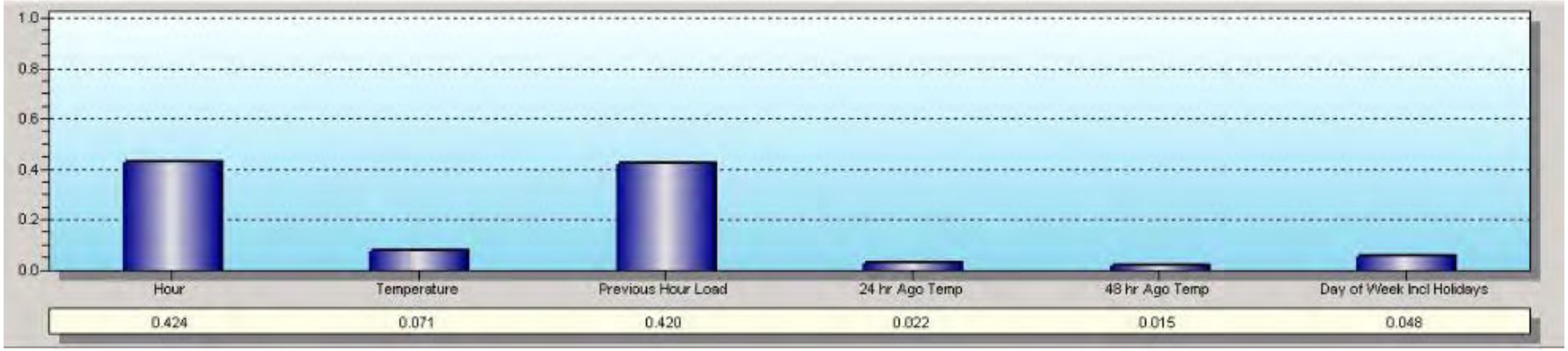
	Hour	Temperature	Previous Hour Load	24 hr Ago Temp	48 hr Ago Temp	Day of Week Incl Holidays	Actual Load
1	0	84	12984.172	78.5	82	1	12052.491
2	1	83	12052.491	70	80	1	11406.383
3	2	83	11406.383	69	76	1	10984.624
4	3	82	10984.624	69	75	1	10747.635
5	4	82	10747.635	72	75	1	10849.012
6	5	81	10849.012	73	74	1	11433.276
7	6	79	11433.276	74	74	1	12365.329
8	7	79	12365.329	74	74	1	13136.045
9	8	78	13136.045	76	75	1	13864.401
10	9	79	13864.401	78	77	1	14259.09
11	10	79	14259.09	82	80	1	14576.561
12	11	78	14576.561	83.5	82	1	14729.459
13	12	79	14729.459	85	84	1	14715.28
14	13	79	14715.28	84	86	1	14659.616
15	14	79	14659.616	67.33333333	87	1	14398.177
16	15	72.75	14398.177	88.5	88	1	14239.96
17	16	73	14239.96	90.5	89	1	14212.895
18	17	73.33333333	14212.895	92	89	1	14188.923
19	18	77.66666667	14188.923	92	90	1	14075.644
20	19	78	14075.644	92	90	1	13852.38
21	20	78	13852.38	90	89	1	13712.71
22	21	80	13712.71	90	87	1	13681.636
23	22	78	13681.636	88	86	1	12928.871
24	23	78	12928.871	87	85	1	12130.917
25	0	77	12130.917	84	78.5	2	11450.251
26	1	78	11450.251	83	70	2	10956.724
27	2	79	10956.724	83	69	2	10612.272

Neural-Net Training



Best net statistics

R-squared	0.996521
Avg.error	91.26518
Correlation	0.99829
MSE	13960.78
RMSE	118.1557
% in range	0.0%
% same sign	100.0%



Neural-Net Predicting

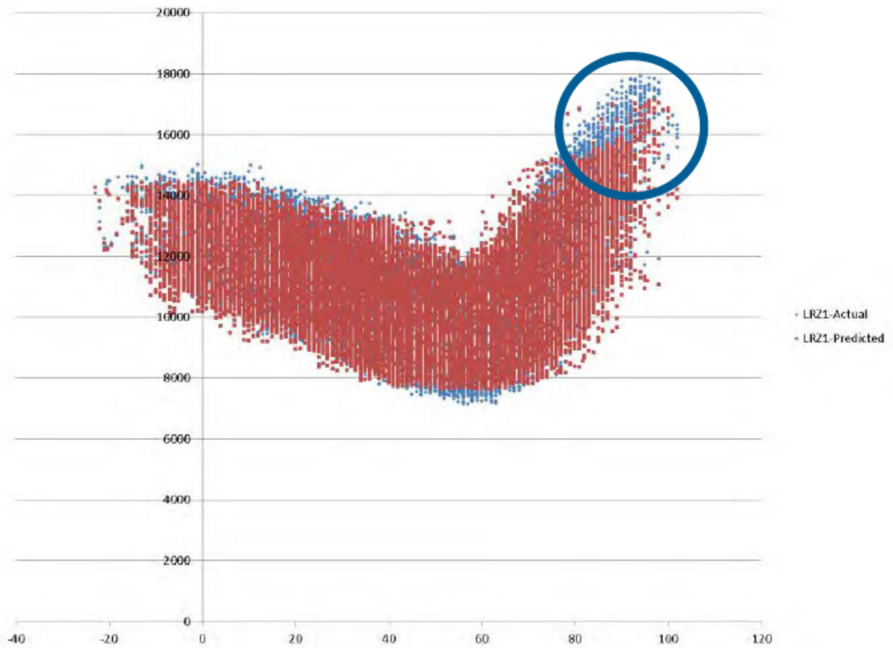
- 30 years of historical weather
  - 1989 to 2017

- Neural-Net applied to 30 years of historical weather to predict load

- Output is 30 weather year load shapes at 5 year normalized economy
  - i.e. Predicted 2018 load with1999 weather

Extreme Temperature Verification

- Verify load training at extreme temperatures is accurate
- Less data points at temperature extremes for neural-net training



Load Forecast Adjustment

- Average of 30 predicted load shapes adjusted to match LRZ's 50/50 zonal peak load forecast for study year
- Ratio of 1st years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast
- Results in 30 Planning Year weather load shapes
  - i.e. 2019-20 PY load if we have 1995 weather

Economic Load Forecast Error

- Use Projected and Actual GDP Growth Rates for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for GDP growth (historic)
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error

Economic Load Uncertainty

- The 2018/19 PY LOLE study showed that the economic load uncertainty modeling resulted in a 0.2 percentage point increase to the MISO Planning Reserve Margin

	Load Forecast Error (LFE) Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	**Probability to assigned to each LFE**				
1.19%	10.4%	23.3%	32.6%	23.3%	10.4%

Advantages in Load Modeling with historical weather

- Multiple load shapes based on weather more accurately capture
  - Variance in load shapes
  - Variance in peak load
  - Seasonal load uncertainty
  - Frequency and duration of severe weather patterns

- Decouple weather and economic uncertainty

Unit Data

- Unit Name
- Unit Physical Local Resource Zone (LRZ)
- Installation Date
- Retirement Date
- Type (Thermal, Curtailable Load, Renewable)
- Unit Summary Type
  - Thermal (Nuclear, Fossil Steam, Combustion Turbine, Hydro, Pumped Storage Hydro)
  - Curtailable Load (Demand Response)
  - Renewable (Intermittent Resources such as Wind, Run-of-River Hydro, Biomass and Energy Efficiency)
- Thermal Units
  - Utilize the GVTC for a peak capacity and each unit's monthly Net Dependable Capacity (NDC) submitted in PowerGADS determines each unit's monthly capacity profile

Forced Outage Rates & Unit Maintenance – Thermal Units Only

- Forced Outage Rates
  - Time to Repair
  - Time to Failure
- Fixed Maintenance – Typically Nuclear Units
  - Begin Date
  - Stop Date
- Planned Outage Rates
  - Percentage of the year in which a unit will be on scheduled maintenance
  - Planned Outage Factor + Maintenance Outage Factor from PowerGADS
- Maintenance scheduled on days with maximum reserves

Curtailable Load Units (Energy Limited)

- SERVM dispatches Demand Response (DR) based on several constraints
  - Days per week
  - Hours per day
  - Hours per year
  - Dispatch price
- Use limitations to model fatigue
  - Minimum Megawatt (MW) – Zero
  - Maximum Megawatt (MW) – Monthly Profile

Demand Side Management (DSM)

- Renewable Units
- Net Hourly Load Modification
  - Maximum Megawatt (MW) – Monthly Profile
  - Positive values decrease load

Non-Firm Support

- Represents benefit of being part of Eastern Interconnect
- 1 MW of non-firm support reduces requirement by 1 MW
- Reliability targets highly sensitive to fluctuations in non-firm support
- LOLE study uses set MW amount of non-firm

Firm Imports

- External resources FRAP’ed or Offered in MECT are included in LOLE modeling
- External purchases are modeled similar to MISO units
- Modeled from external region to MISO
- Firm imports are only modeled in MISO PRM model and not zonal LRR model
- External firm imports impact LOLE based on unit characteristics

Firm Exports/Sales

- Capacity that is ineligible for MISO PRA is excluded from MISO and zonal models
- Only units that have capacity obligations outside of MISO are designated as sold in the LOLE model
- External firm exports impact LOLE based on unit characteristics

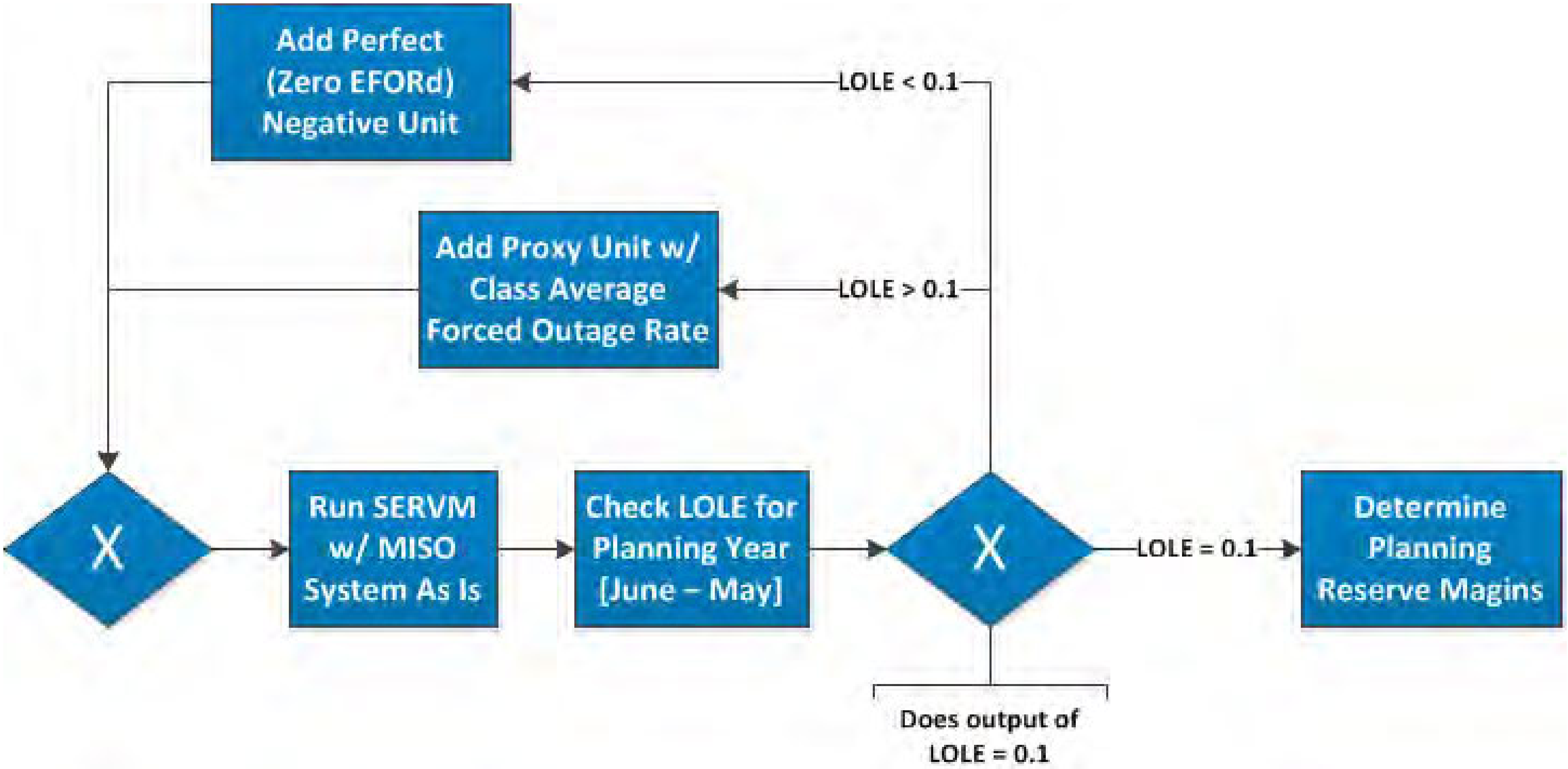
SERVM Simulation Frameworks

30 Weather Years (equal probability) x 5 Economic Uncertainties (Normal Distribution) = 150 Load Scenarios

150 Load Scenarios x 300 unit outage draws = 45,000 8760 hour simulations

** Scenarios are an example of framework and are not fixed

Capacity Adjustment Flowchart



LOLE Study Deliverables to MISO's Planning Resource Action (PRA)

- The LOLE study has four deliverables to the Planning Resource Auction
  - MISO PRM UCAP [%]
  - Local Resource Zones (LRZ) Local Reliability Requirement (LRR) per unit
  - LRZ Capacity Import Limit (CIL)
  - LRZ Capacity Export Limit (CEL)
- LOLE deliverables are applied to updated demand forecasts to calculate PRA requirements

Calculation of MISO PRM [%]

MISO Planning Reserve Margin (PRM)	2018/2019 PY	Formula Key
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support ICAP (MW)	4,938	[D]
Firm External Support UCAP (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-4,550	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-4,550	[G]
ICAP PRM Requirement (PRMR) (MW)	150,289	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,719	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.3%	[K]=[I]-[A]/[A]
Post-Processing accounting for non-firm external support		
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	147,302	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	136,388	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.1%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.4%	[Q]=([O]-[A])/[A]

*MISO Capacity Market procures on UCAP

Calculation of Zonal Requirements and Example PRA Requirements

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]

Important LOLE Fundamentals Takeaways

- LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand
  - LOLE is used to study Generation(Resource) Adequacy
  - Probabilistic analysis accurately captures uncertainty risk
- MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:
  - 1-day in 10-years
  - Aligns with NERC standards
- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin (Planning Reserve Margin)
  - LOLE models utilize an Equivalized Transportation Model to determine Planning Reserve Margin and Local Reliability Requirements
- All Market Participants are encouraged to participate in the stakeholder process through LOLEWG

Reference Materials

- Past LOLE 101 Documents
  - LOLE 101 (Apil 11th, 2017)
- Loss of Load Expectation Reports
  - 2018 Loss of Load Expectation (LOLE) Study Report
  - Loss of Load Expectation Working Group (LOLEWG)
  - 2018 Wind Capacity Report
  - Resource Adequacy Documents
- Resource Adequacy Documents
  - BPM
    - BPM 011 - Resource Adequacy
  - MISO Tariff: Module E-1
  - NERC Standard BAL-502-RF-03

Appendix

LOLE Terms and Definitions

- **Installed Capacity:** The installed capacity that is physically located within the zone. The ICAP is the output that the generator tested for its max summer output.
- **Unforced Capacity:** The installed capacity less forced outage rates. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.
- **Adjustment to UCAP:** The UCAP capacity adjustment within the zone to drive the zone to the “1 day in 10” criteria if the zone was an island. If a zone is more reliable than “1 day in 10” capacity needs to be removed in order to drive the model to the LOLE metric.
- **LRR (UCAP):** Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet “1 day in 10” loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Peak Demand**: The zone's annual peak demand including transmission losses.
- **Time of Peak Demand (ESTHE):** The date and time of the zones annual peak demand.
- **LRR UCAP per-unit of LRZ Peak Demand**: Zonal specific reserve margin [%], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).
- **Capacity Import Limit**: The amount of capacity that a zone can import from outside their zone reliably during peak load before observing a transmission constraint.
- **Capacity Export Limit**: The amount of capacity that a zone can reliably export out of their zone during peak load before observing a transmission constraint.

LOLE Terms and Definitions

- **Forecasted LRZ Load at MISO Peak**: Zone's load coincident with MISO's annual peak load.
- **Firm External Support:** Represents the external resources offered into planning year PRA and are modeled at the individual unit level.
- **External Non-Firm Support:** Represents the benefit of being part of the Eastern Interconnection, where 1 MW increase of no-firm support reduces requirement by 1MW.
- **Local Reliability Requirement**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **<u>Local Clearing Requirement</u>**: The minimum capacity required to be physically located within a zone to meet the "1 day in 10" Loss of Load Expectation requirement. The LCR is LRR minus the CIL and non-pseudo tied exports.
- **<u>Zone's System Wide PRMR</u>**: The zones share of the total MISO Planning Reserve Requirement that the zone needs to procure on a UCAP basis [MW]. The difference of the zones system wide PRMR minus the Local Clearing Requirement is the capacity that can be cleared outside of the zone (able to import at peak load) to meet the Planning Reserve Margin Requirement.
- **<u>Planning Reserve Margin (PRM):</u>** The reserve margin, capacity above peak load, the entire MISO footprint needs to procure to meet the "1 day in 10" Loss of Load Expectation requirement. The "1 day in 10" Loss of load requirement is the industry standard risk metric.

PRM and LRR Calculations

$$\text{PRM ICAP} = \frac{[\text{Installed capacity} + \text{ICAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{PRM UCAP} = \frac{[\text{Unforced capacity} + \text{UCAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{Each LRZ}'\text{s LRR} = \begin{matrix}\text{LRZ Unforced} \\ \text{Capacity}\end{matrix} + \begin{matrix}\text{LRZ UCAP} \\ \text{Adjustment needed} \\ \text{to meet 0.1 d/y LOLE}\end{matrix}$$

$$\text{LRZ per unit LRR} = \frac{\text{LRR}}{\text{LRZ Peak Demand}}$$