

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

Presentation to the Committee of State Representatives
Sylvan Energy Analytics
February 27, 2026

This work was sponsored by **GridLAB**

Who we are



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

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

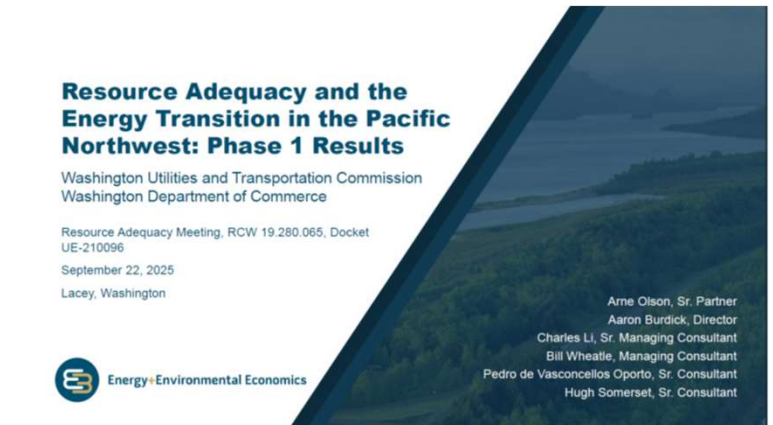


GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

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

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
 - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
 - It projected a 9 GW shortfall by 2030 across the “Greater NW,” with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
 - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
 - Phase 2 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:

1. 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
2. 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)
3. Identify near-term opportunities to support regional resource adequacy based on findings

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	<ul style="list-style-type: none"> Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2 	High
Hydro flexibility	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced) 	Low-to-moderate

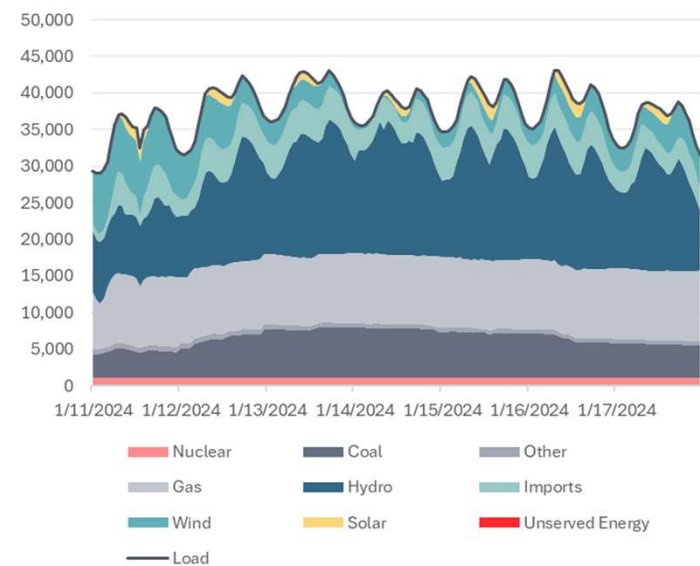
Independent evaluation approach

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

GridPath dispatch simulation approach:

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

Simulated dispatch in January 2024 benchmarking run

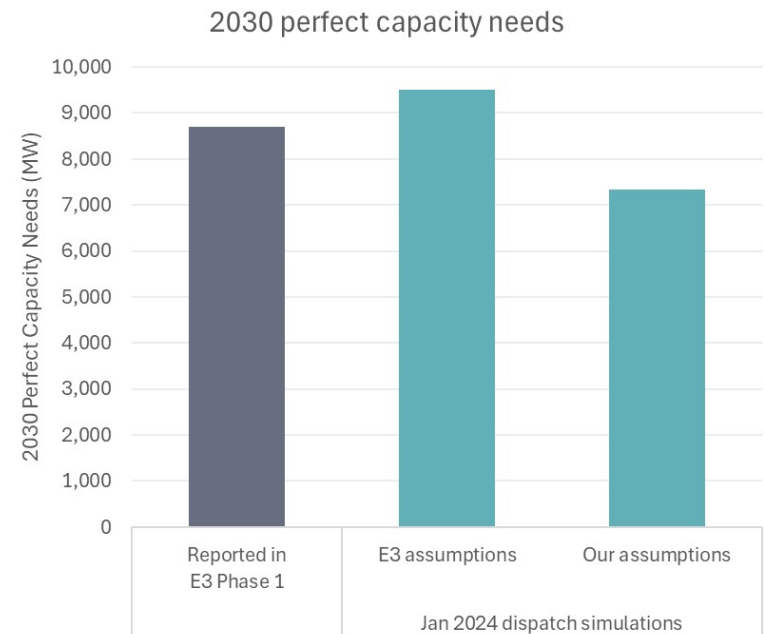


Key assumptions

	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, Dave Johnston 1 & 2, Naughton 1 & 2</u>	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

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

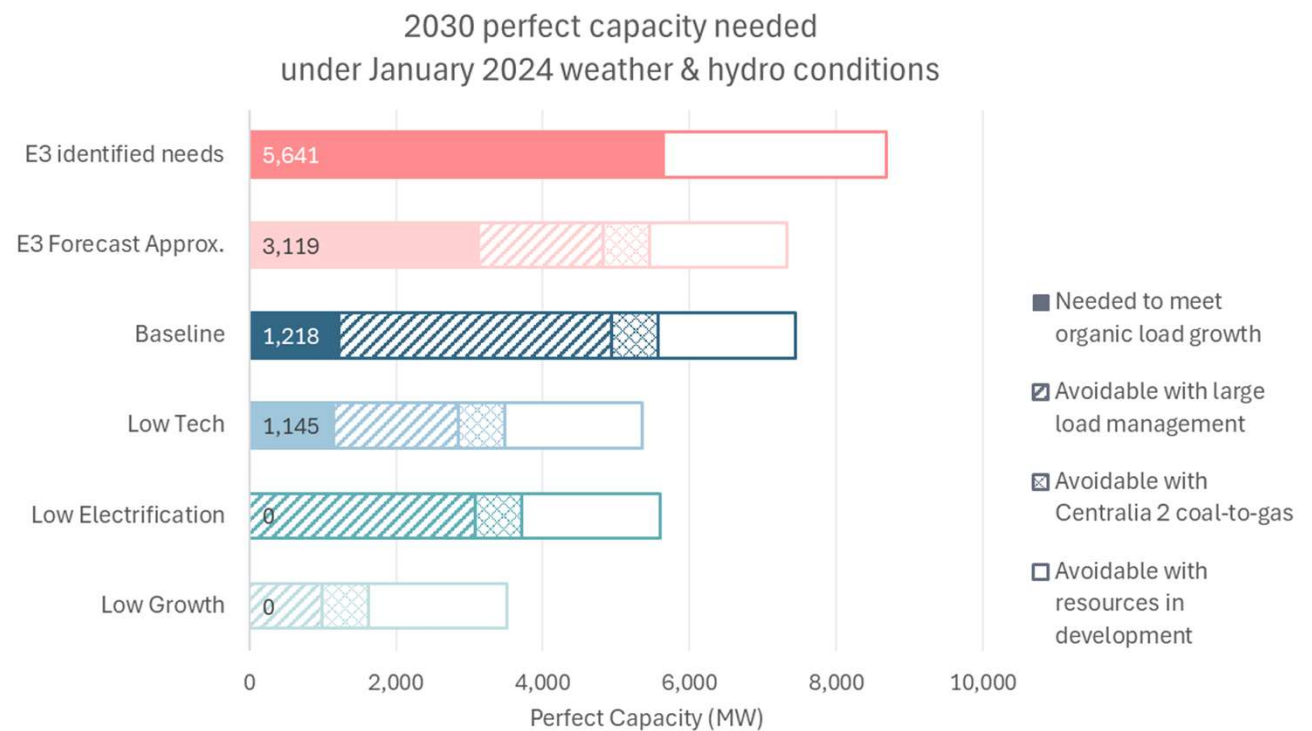
We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

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%
<i>Historical growth in electricity sales (2019-2024, excluding 2020)</i>			1.3%

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

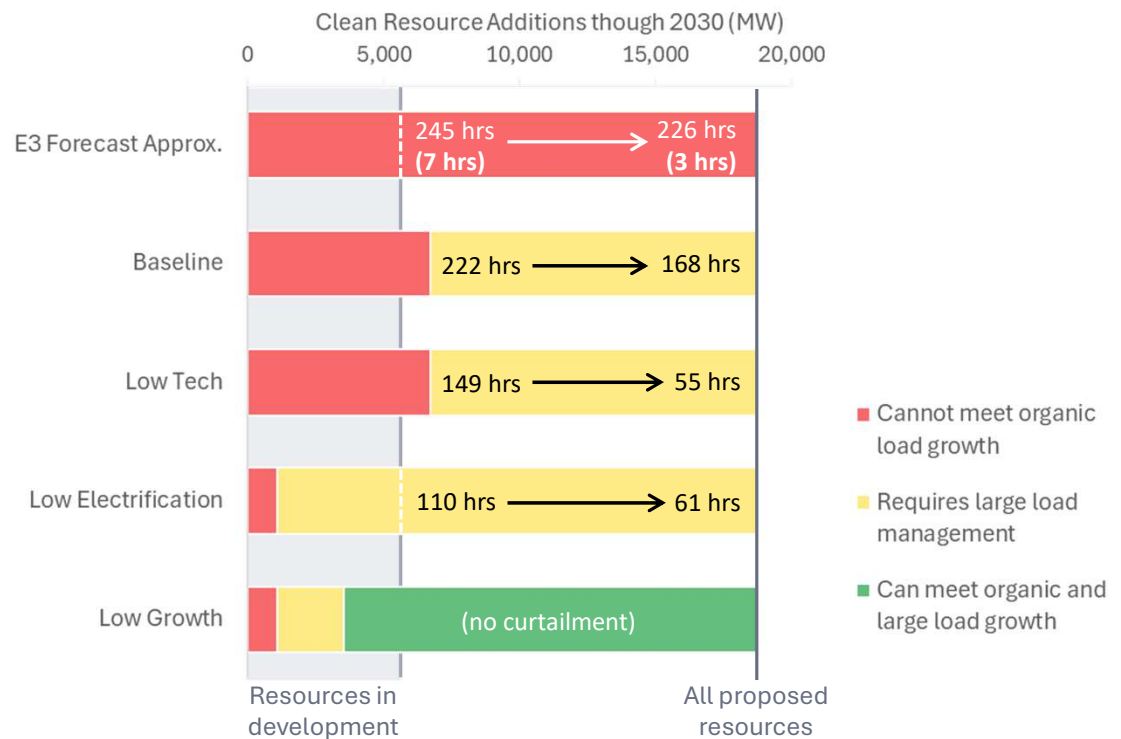
High level findings from independent evaluation

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



High level findings from independent evaluation

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



High level findings from independent evaluation

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

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

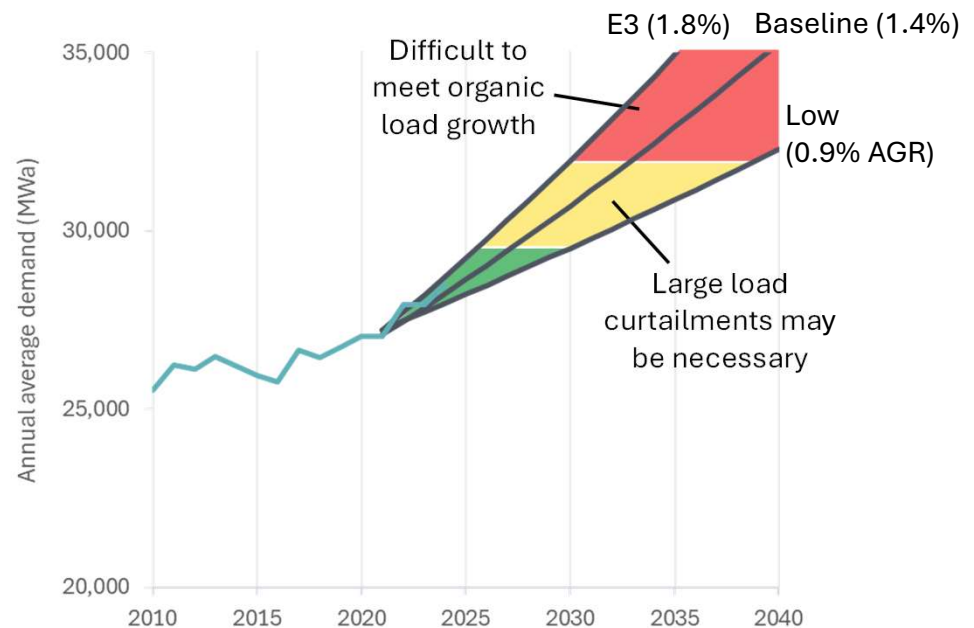
Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

High level findings from independent evaluation

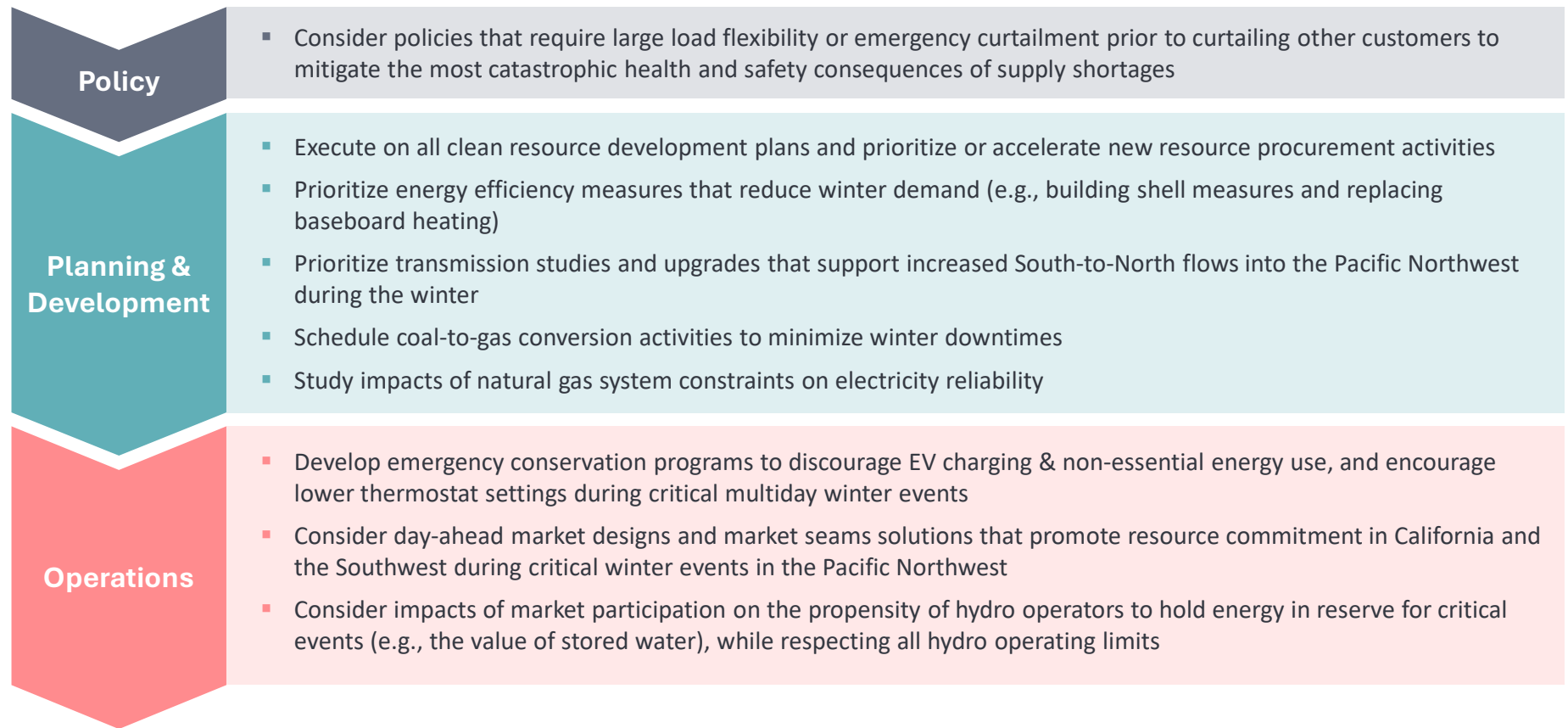
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Our recommendations focus on opportunities to push this need out in time in the interest of lowering costs and potentially leveraging new technologies

Extrapolated* organic load growth trajectories and resource adequacy challenges



Near-term opportunities identified to support regional RA





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



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

Thank you!

For more information, contact:
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Additional slides

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)					Reported by E3 in Phase 1
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
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

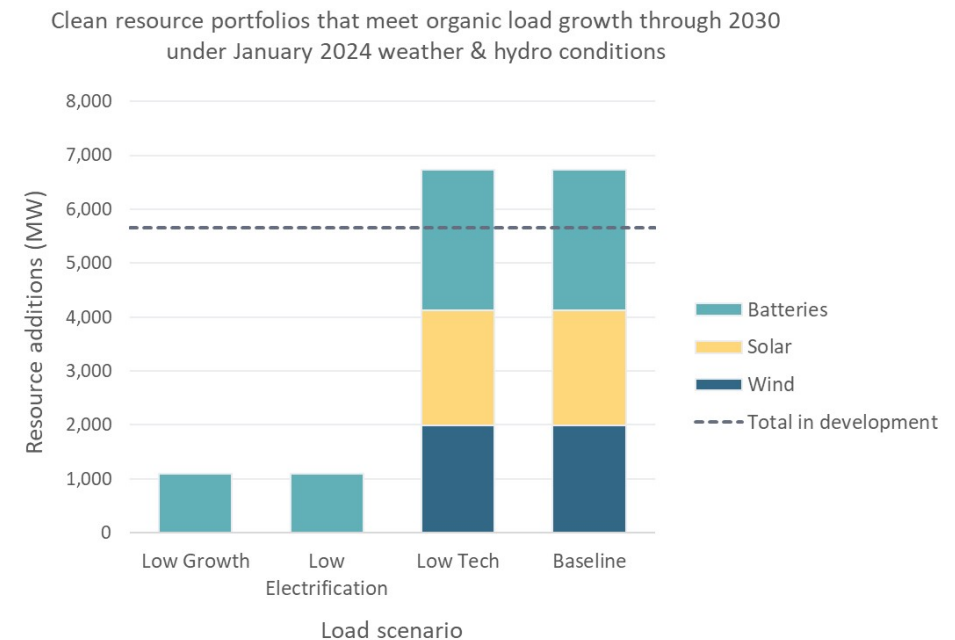
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					Reported by E3 in Phase 1
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
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.

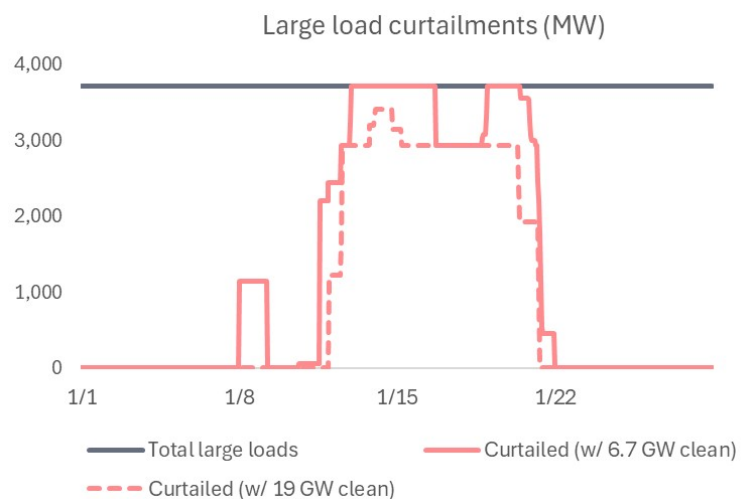
Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- 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)

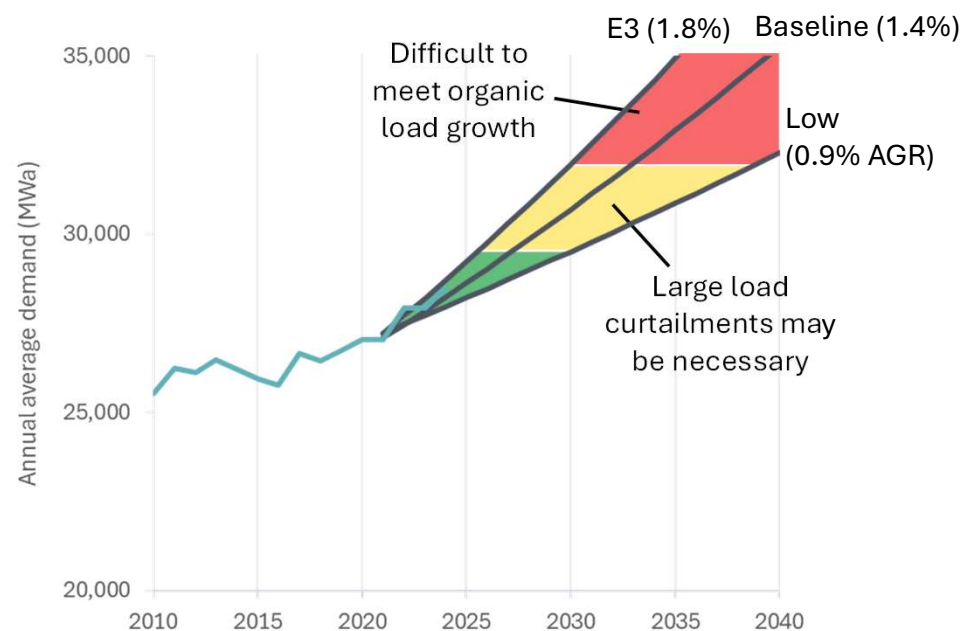
Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario
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Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment 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





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
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Some technical notes

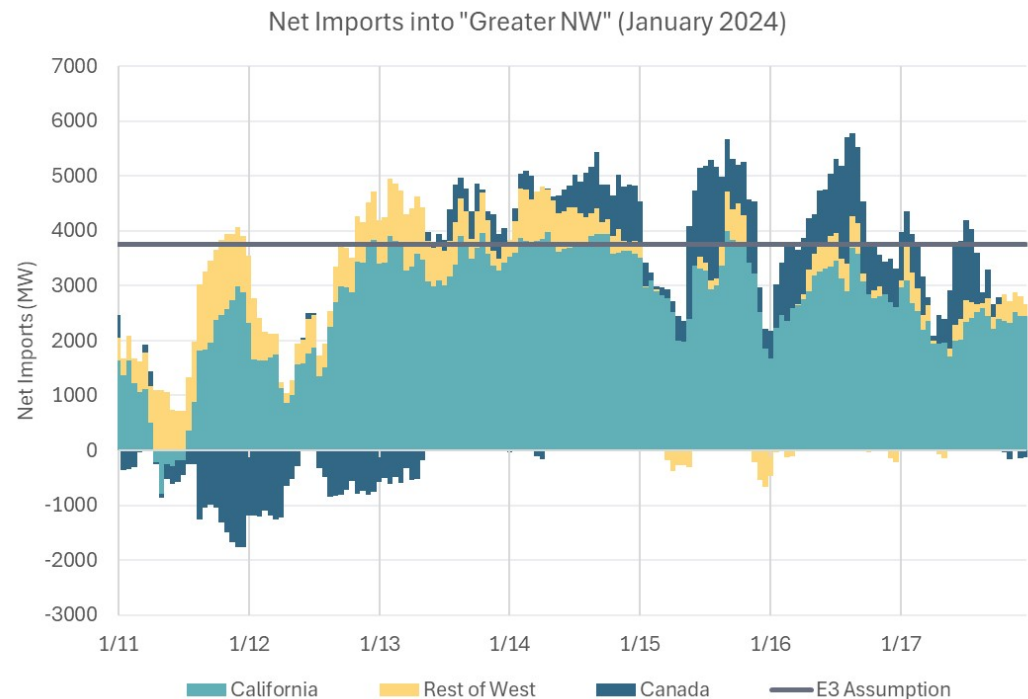
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our “Greater NW” footprint with E3’s due to time and data limitations. Loads and resources likely 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)
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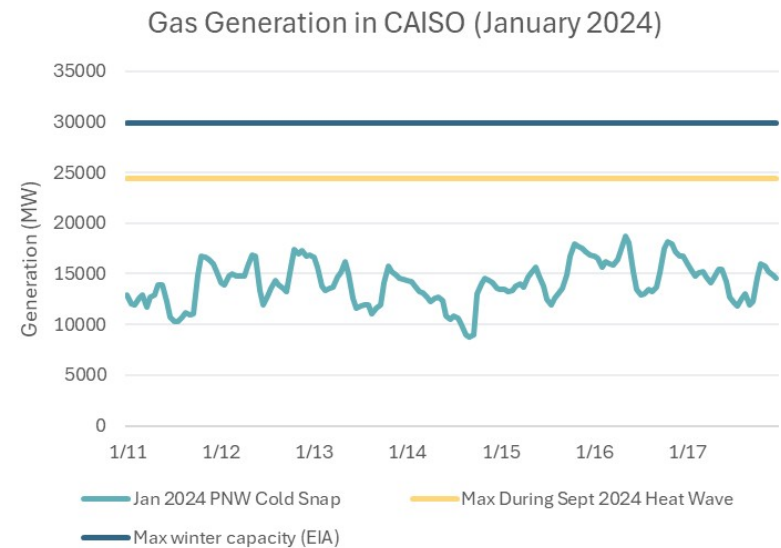
Winter import constraints

- 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:

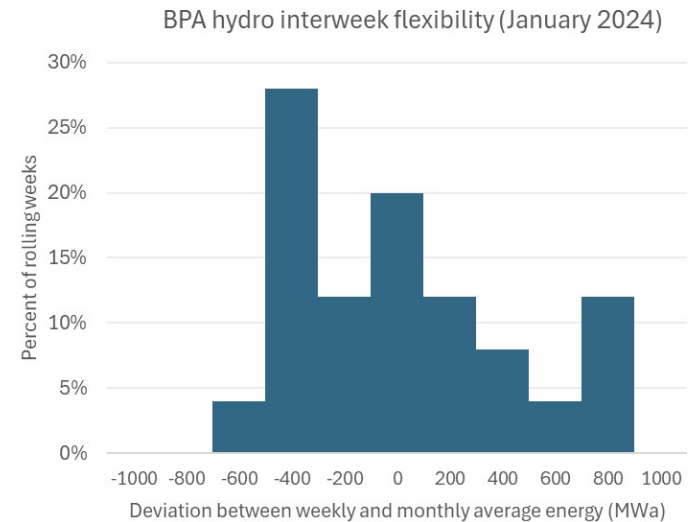
- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize 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 overstating 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?

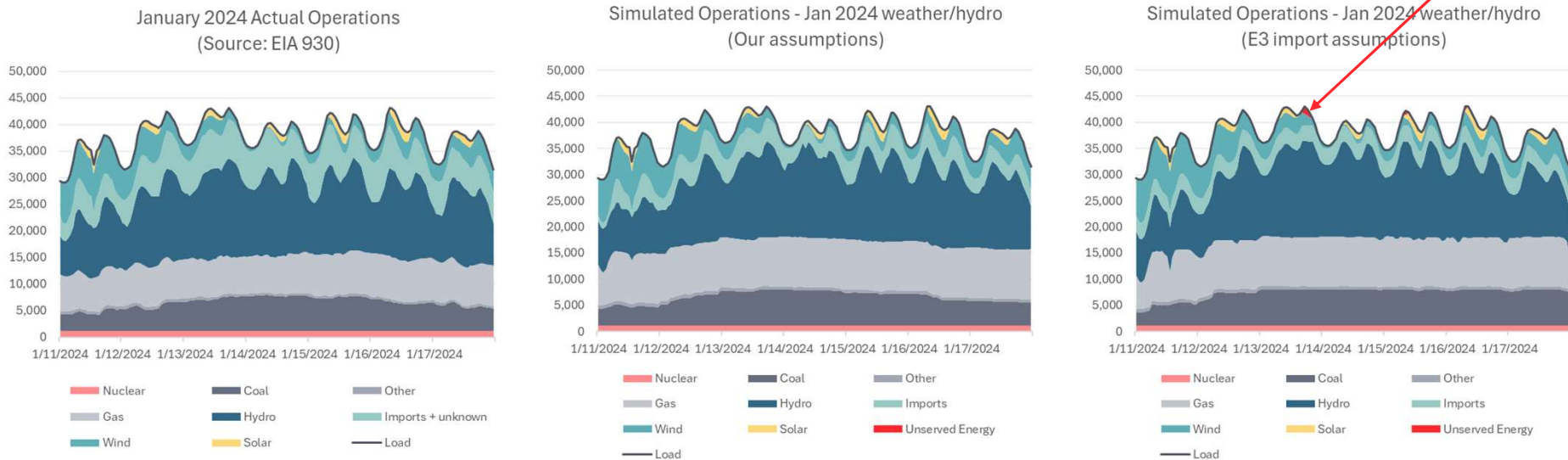
Near-term opportunity:

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

2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

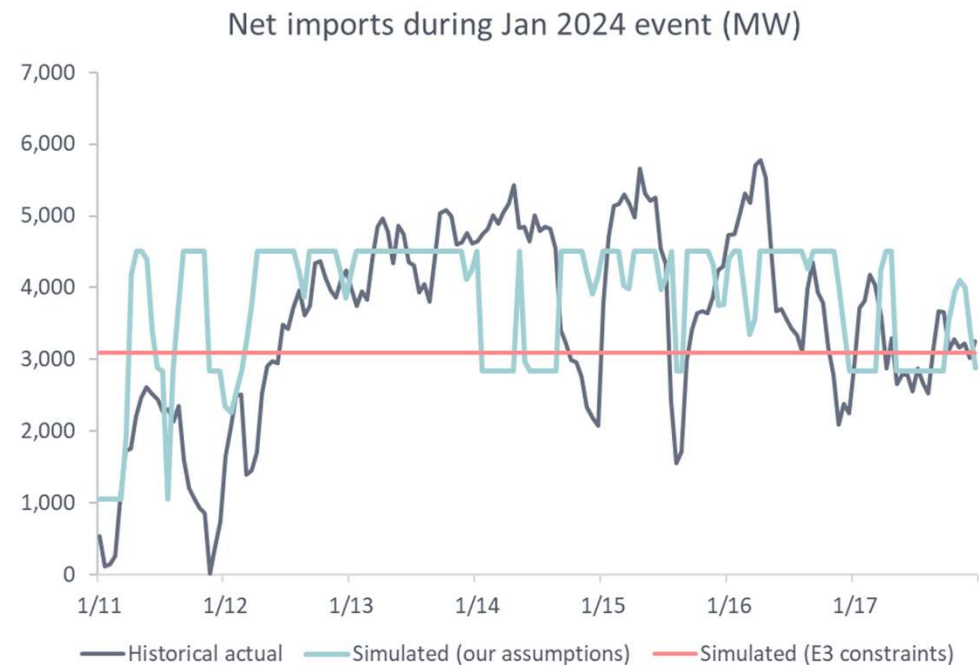
Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



*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)

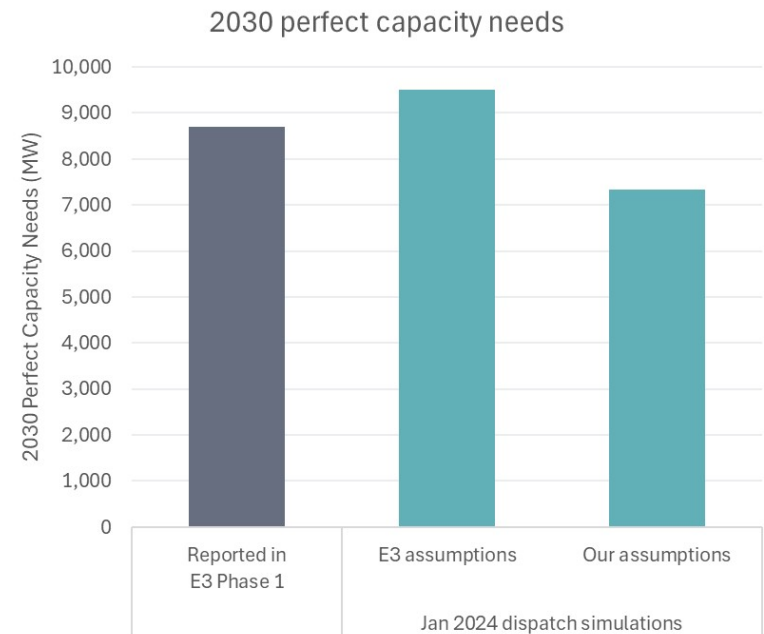
2024 benchmarking

- 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



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



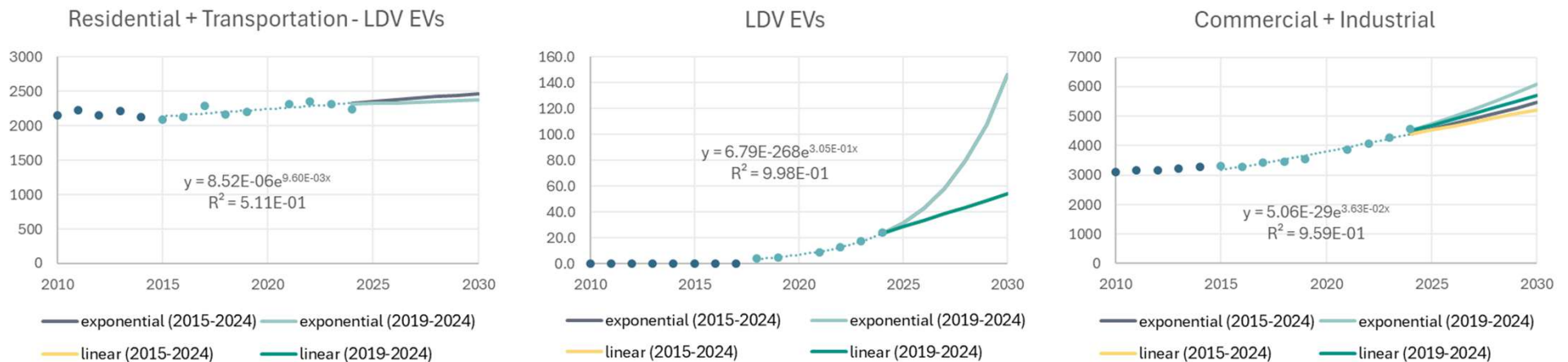
Electricity demand scenarios for 2030

- 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 H₂ 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 H₂ 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%

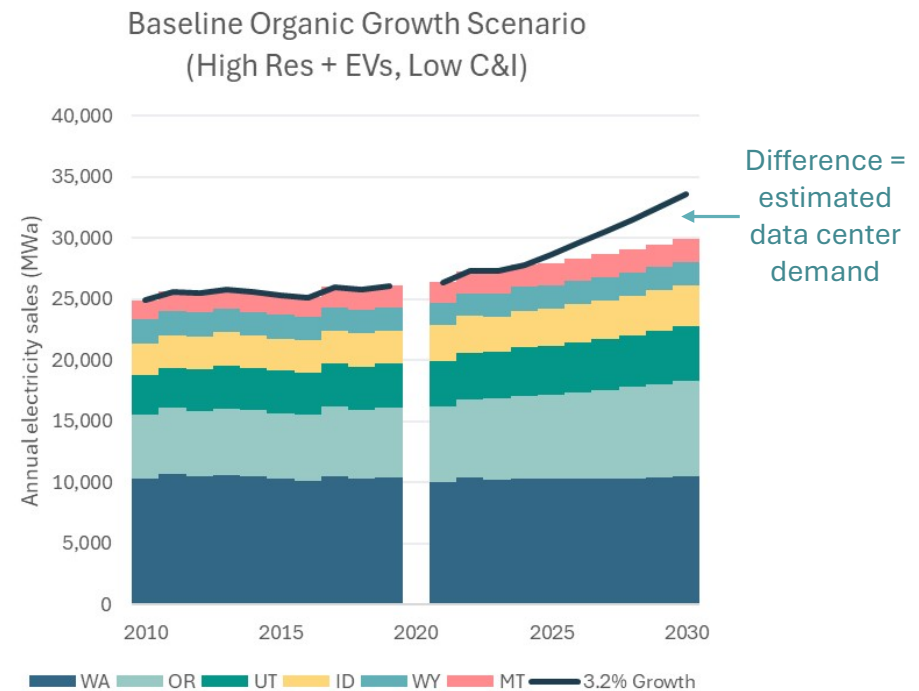
¹E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

²NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H₂ 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



Alternative 2030 load scenarios

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

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

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



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



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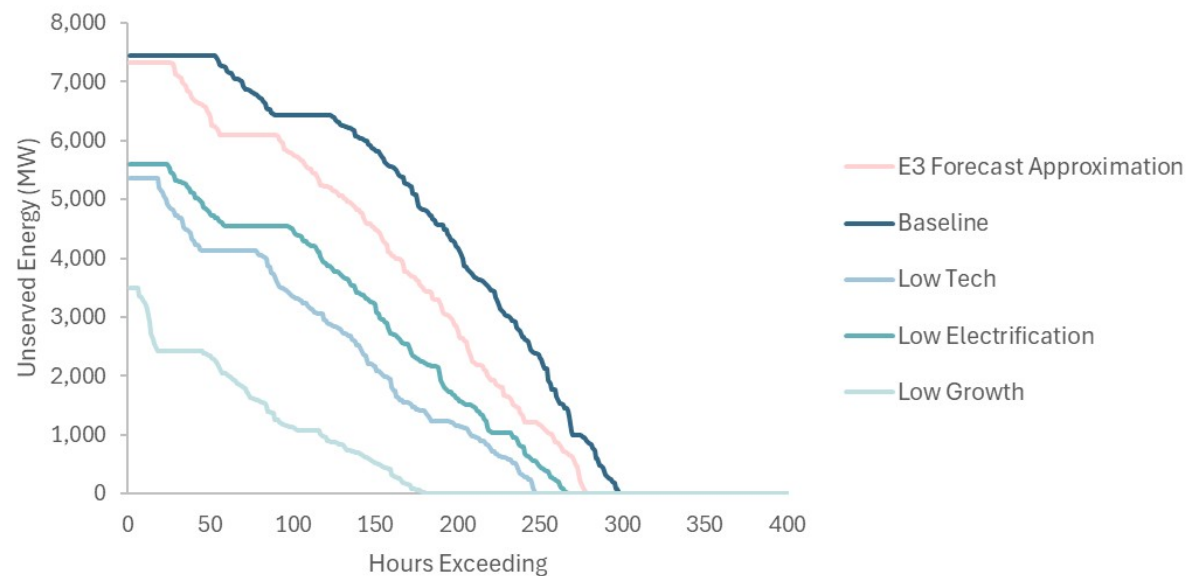
Our findings generally corroborate E3's high level problem statement

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:

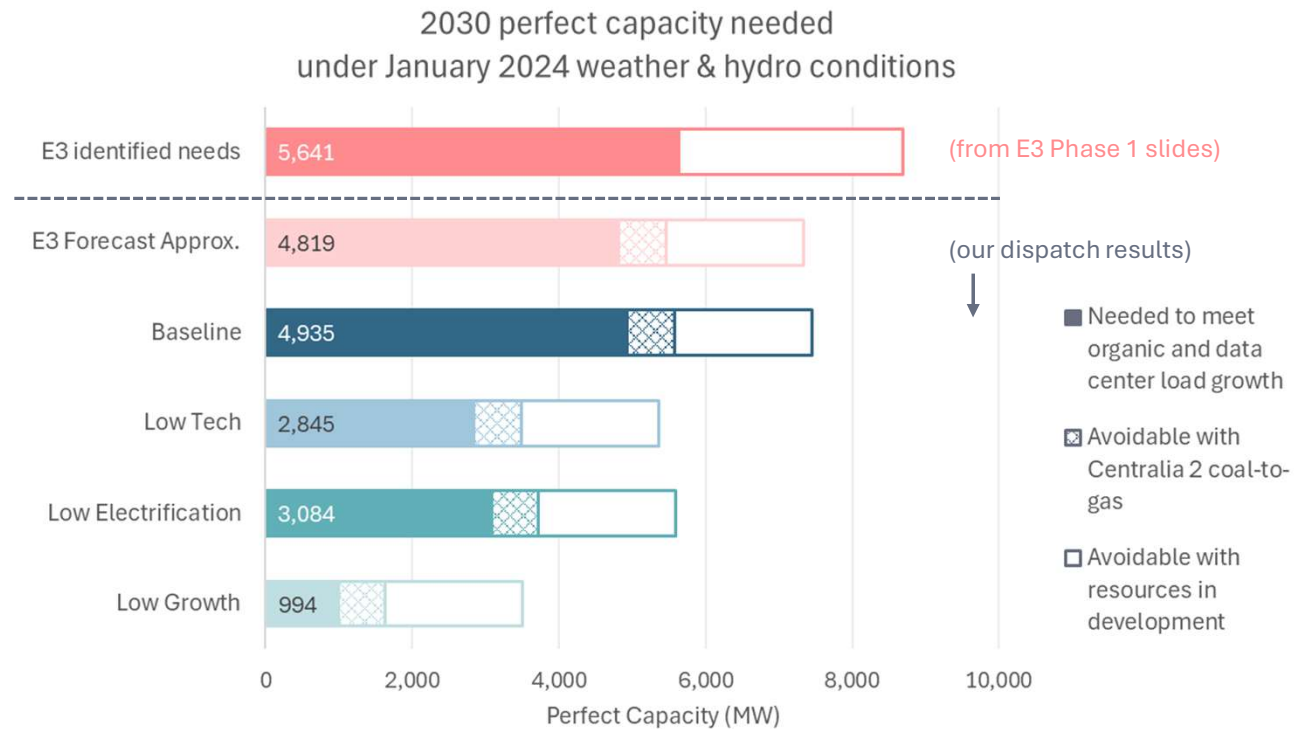
- These results are based on “operational” runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

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



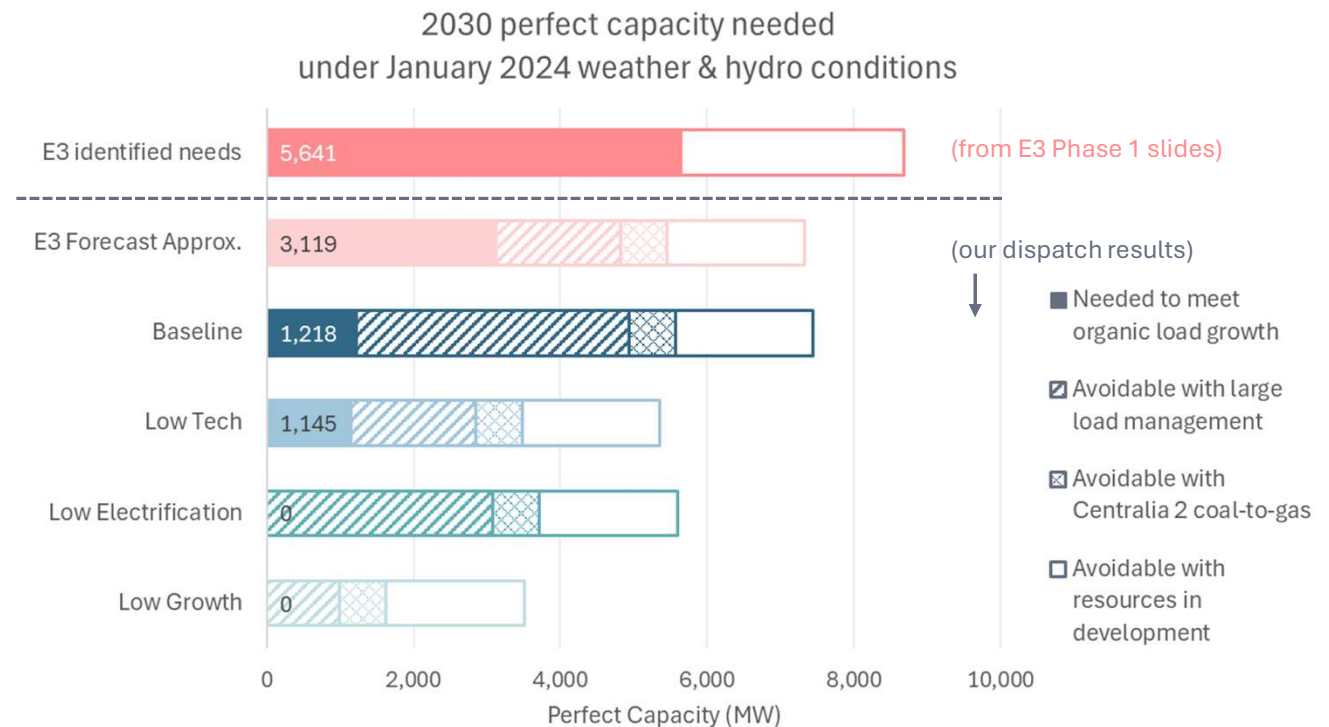
How sensitive are 2030 resource adequacy needs to future load growth?

- 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

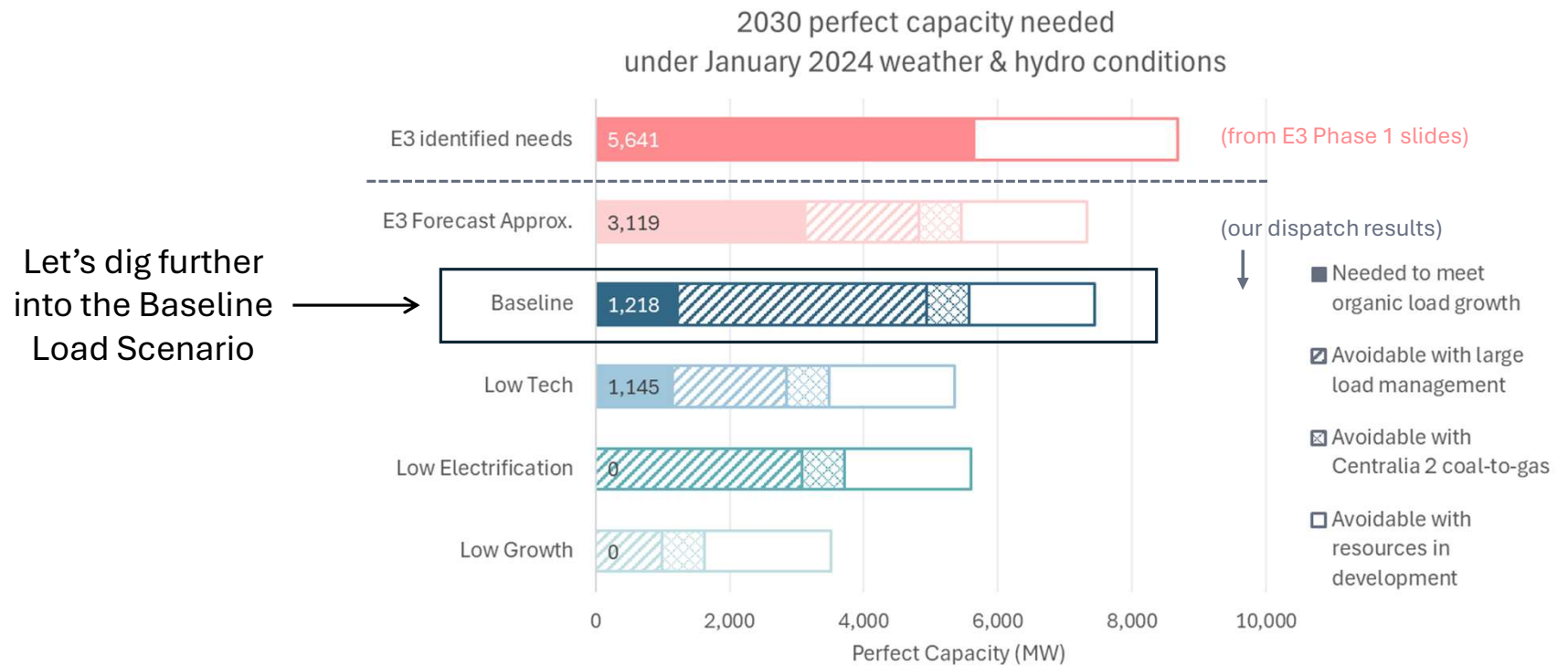


“Connect and manage” for large loads and resource adequacy

- 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



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

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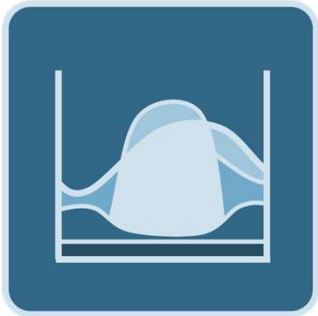

Addressing supply shortages with new clean resources

- 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)

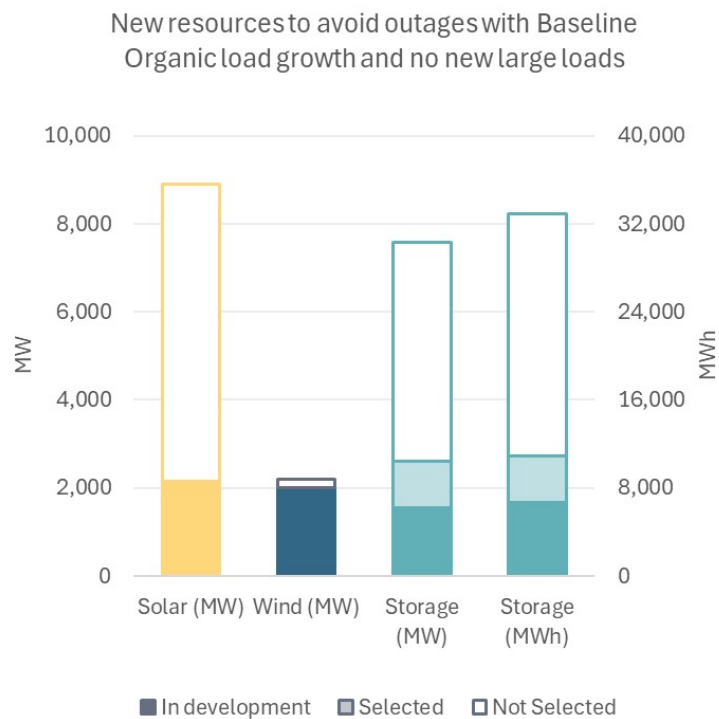
Blended production cost/capacity expansion mode



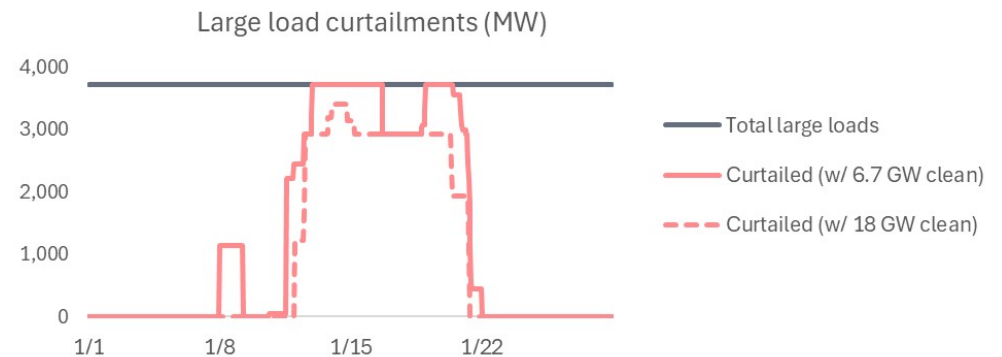
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



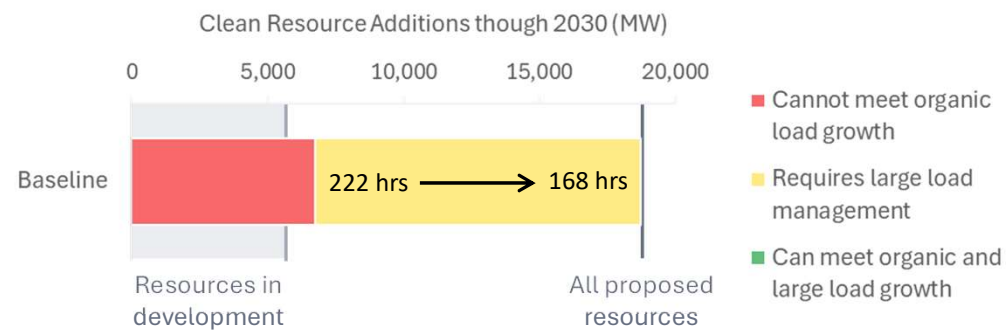
Clean resource additions and large load management in the Baseline scenario



- 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

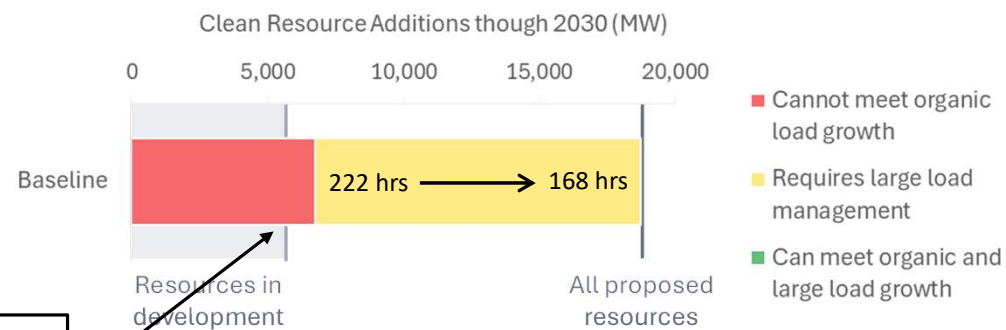


Clean resource additions and large load management across the scenarios



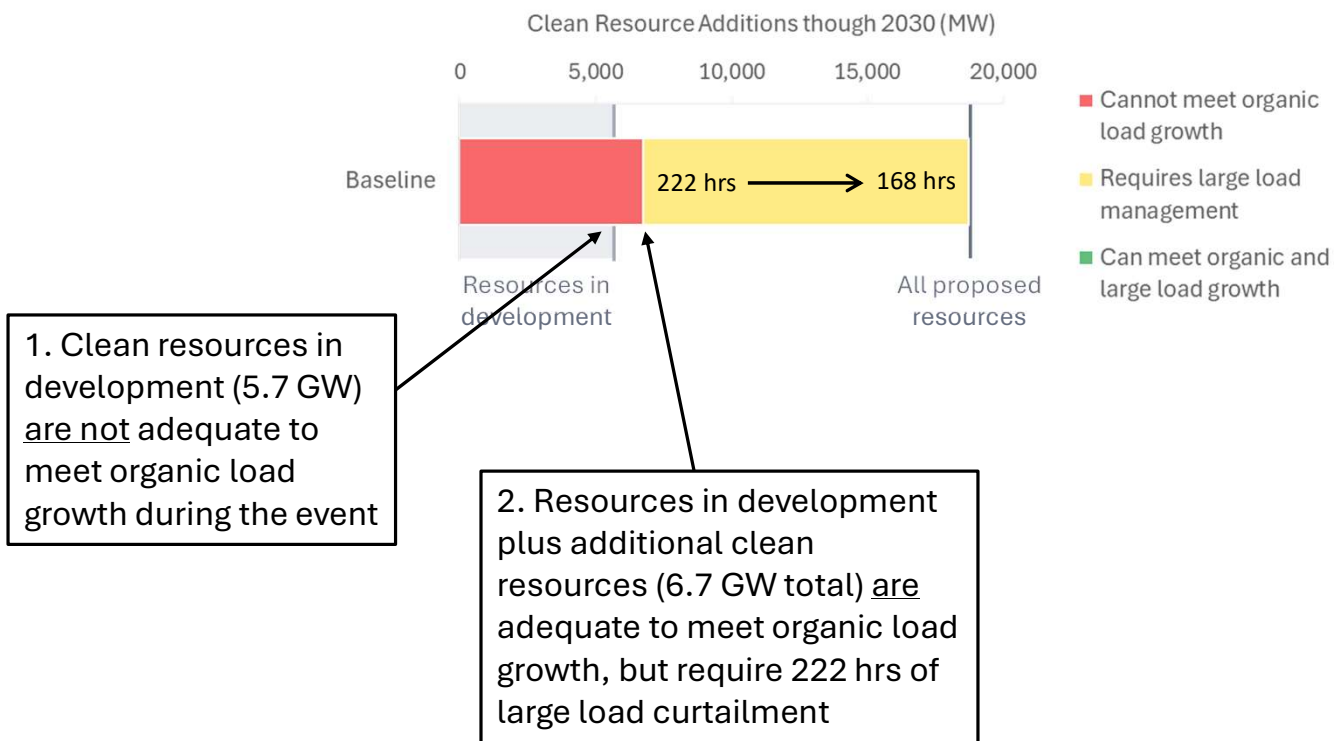
To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

Clean resource additions and large load management across the scenarios

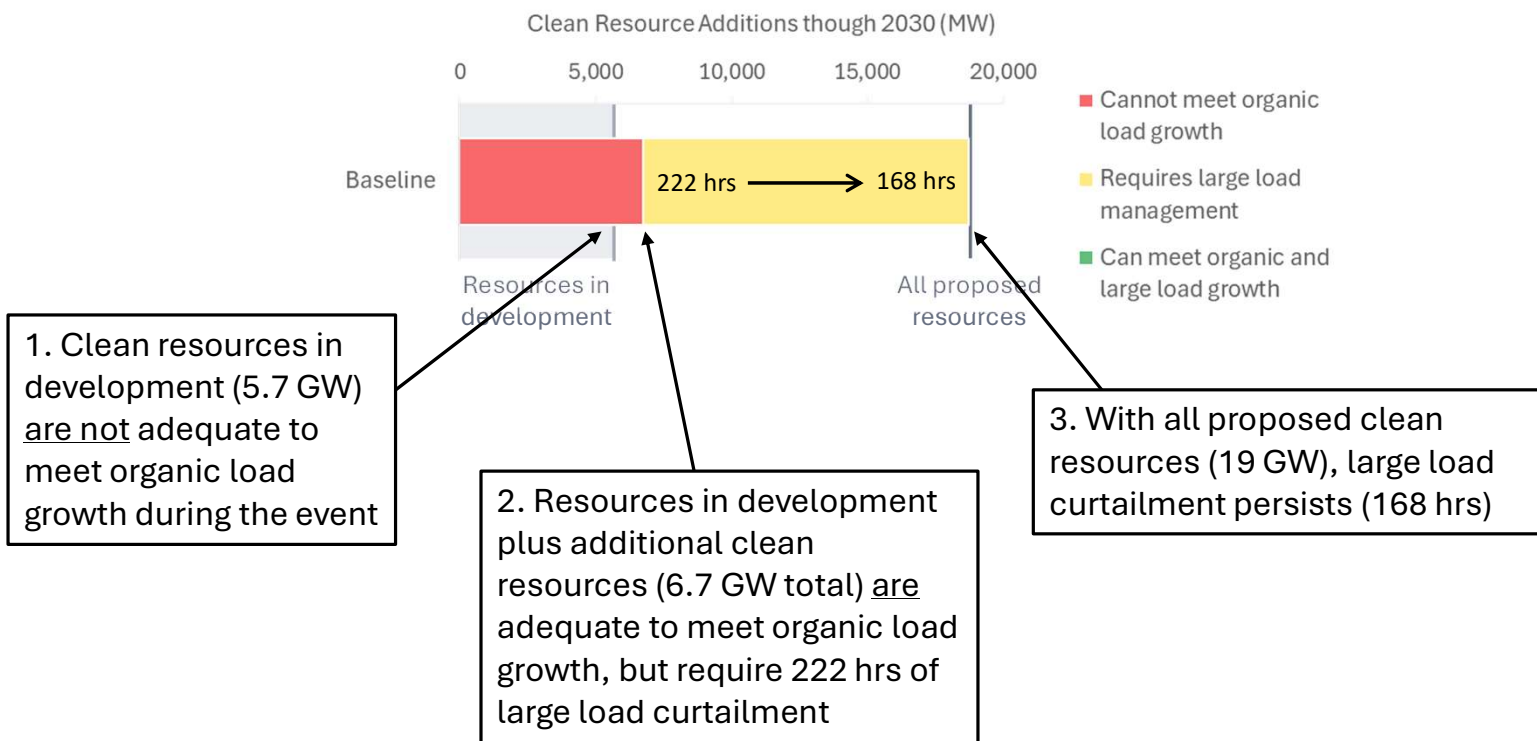


1. Clean resources in development (5.7 GW) are not adequate to meet organic load growth during the event

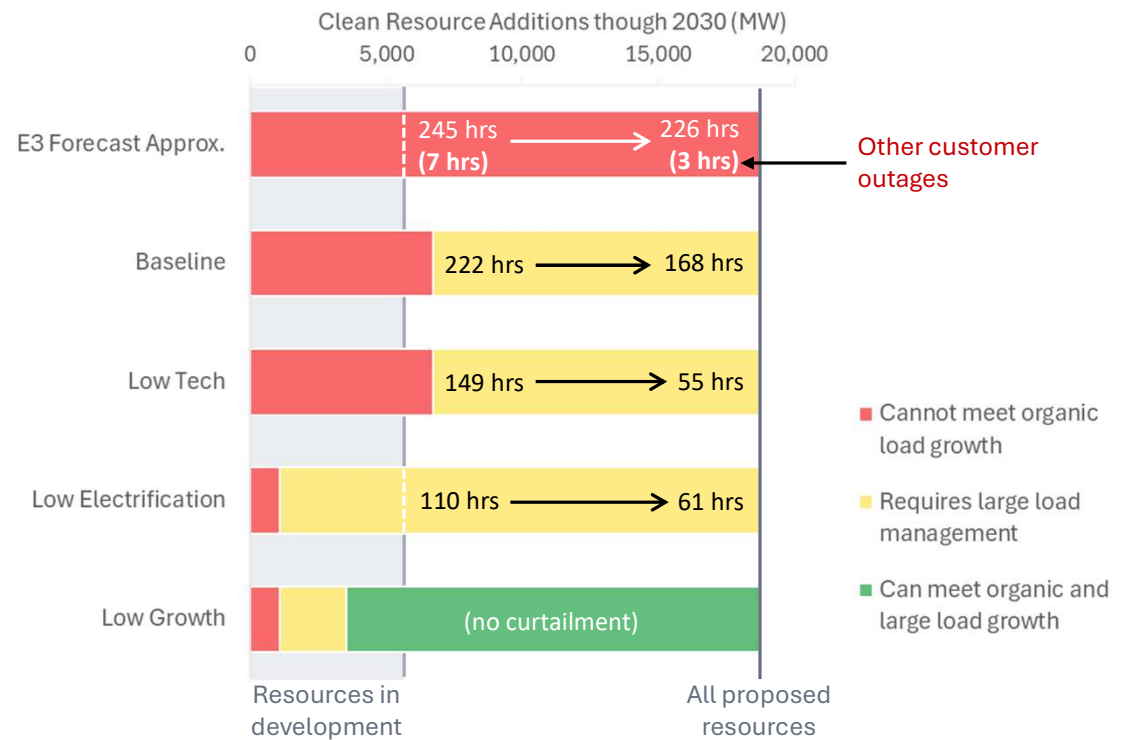
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Clean resource additions and large load management across the scenarios



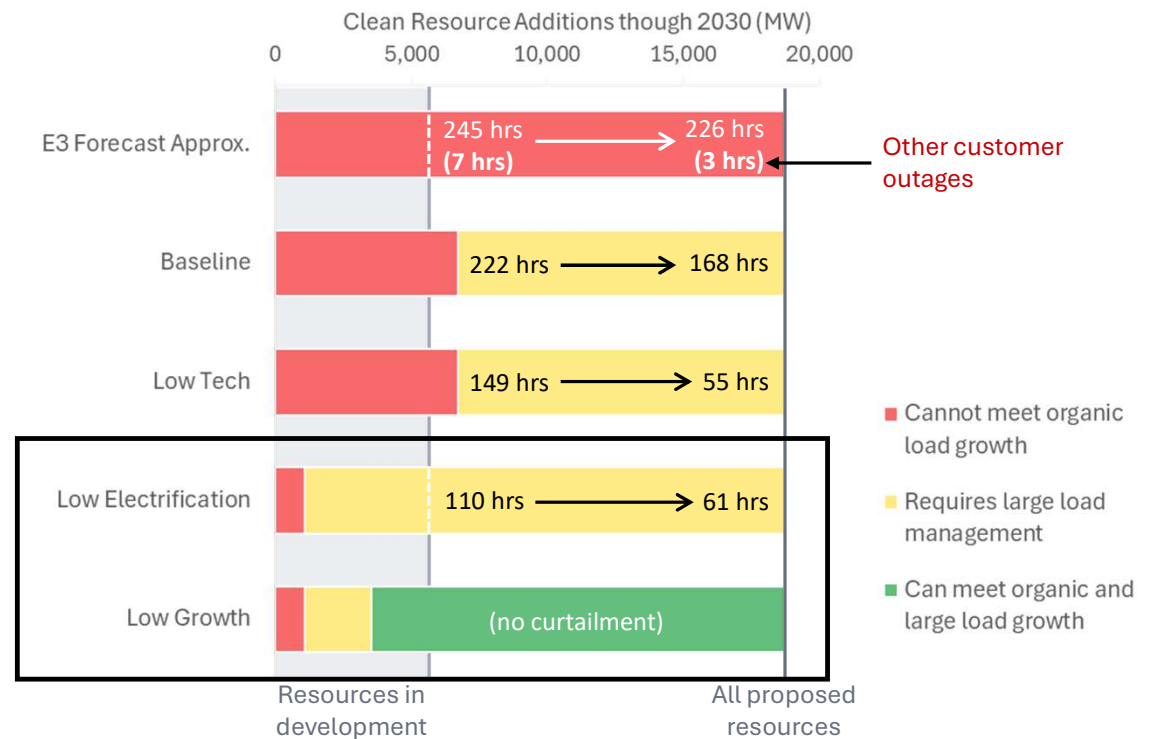
Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios

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

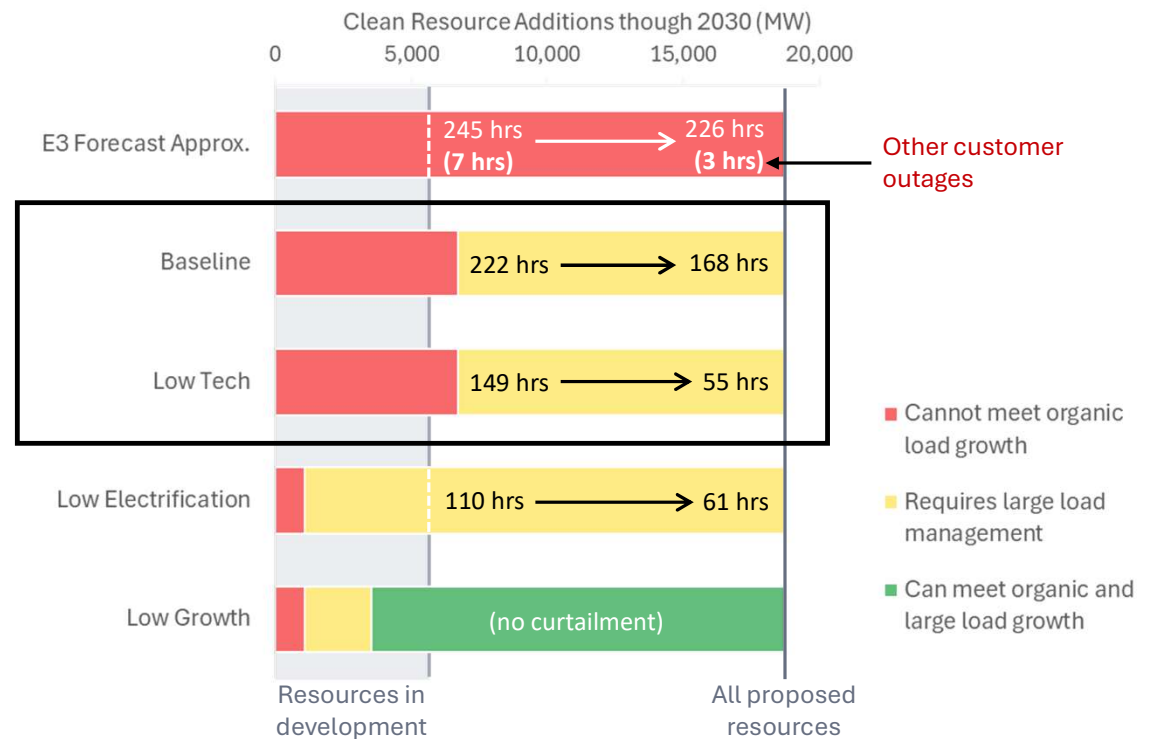
- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)



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)



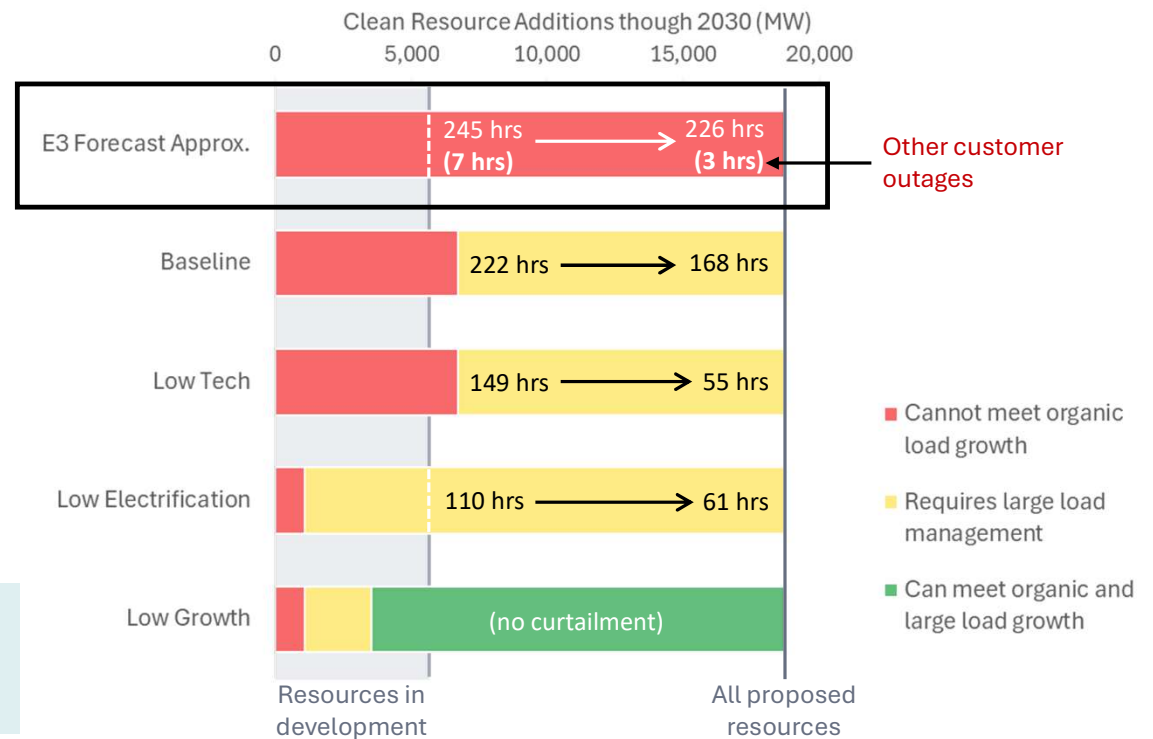
Clean resource additions and large load management across the scenarios

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

- 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

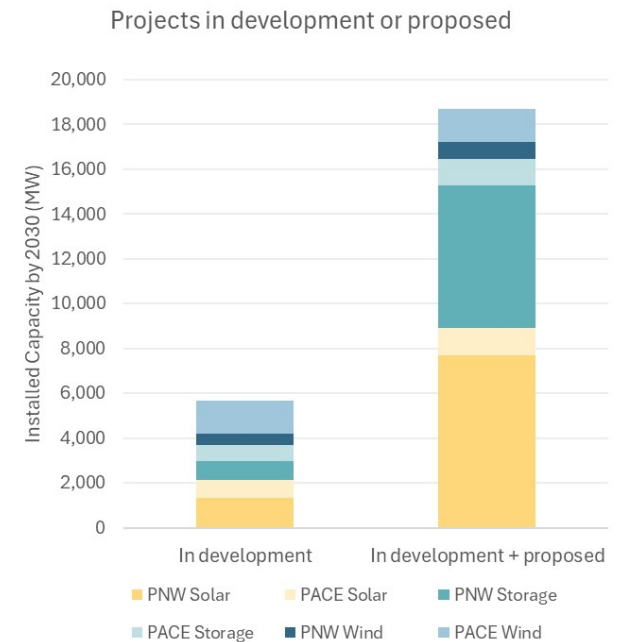


Winter portfolio ELCCs of new clean resources

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)

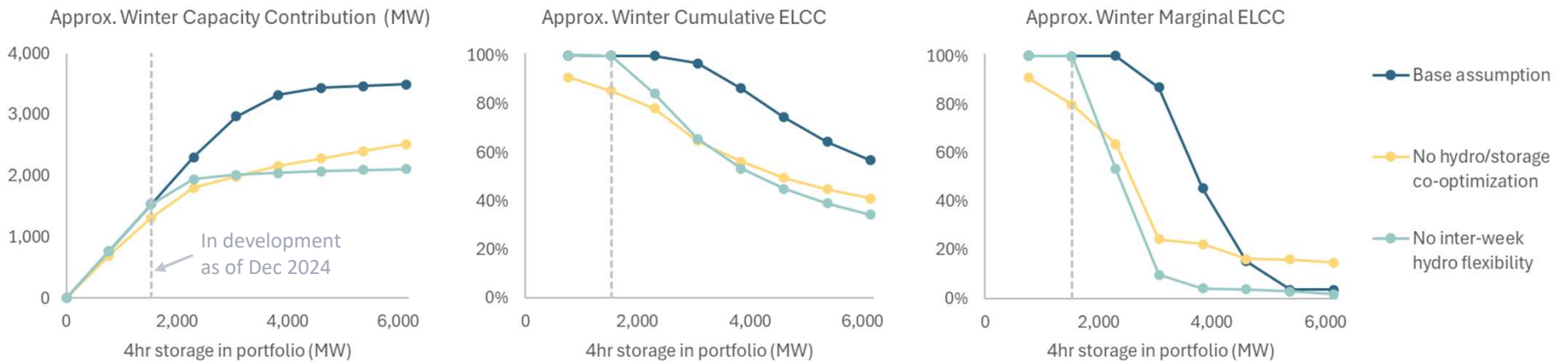


Near-term opportunity:

- 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
 - Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
 - Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



Notes:

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

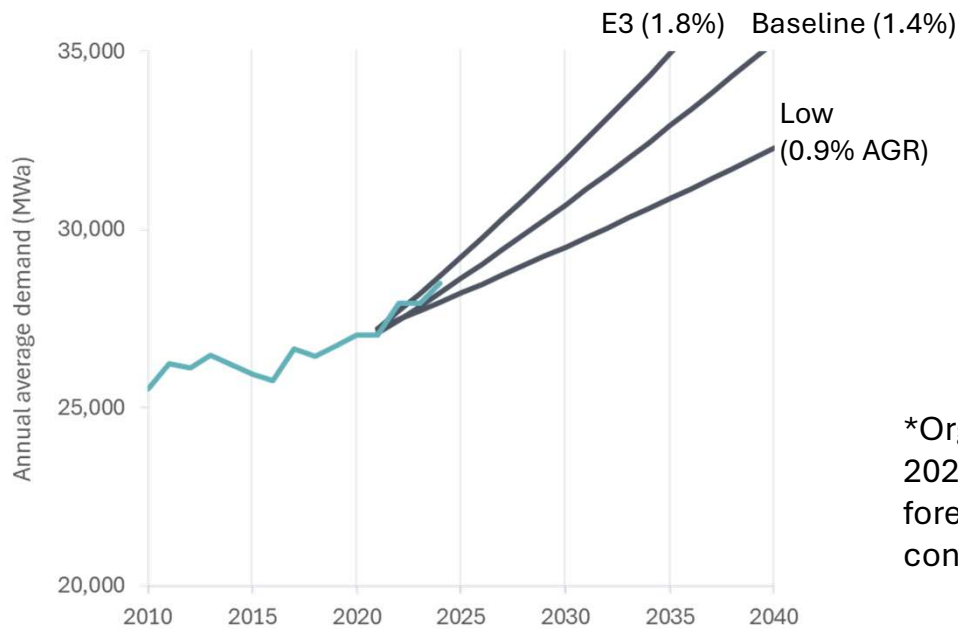


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The need for dispatchable or baseload solutions is not a question of if, but when

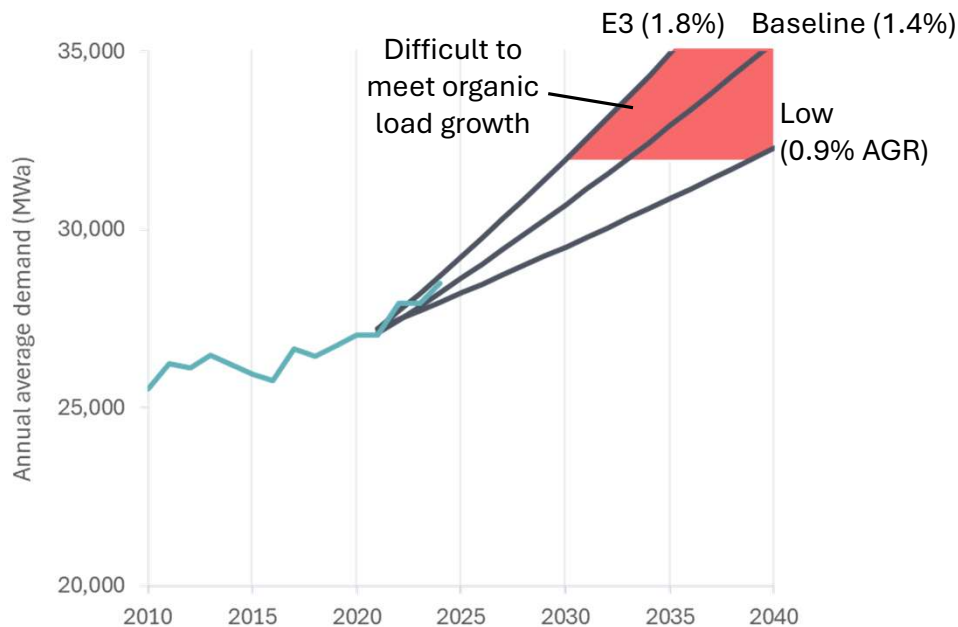
Extrapolated* organic load growth trajectories



*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.

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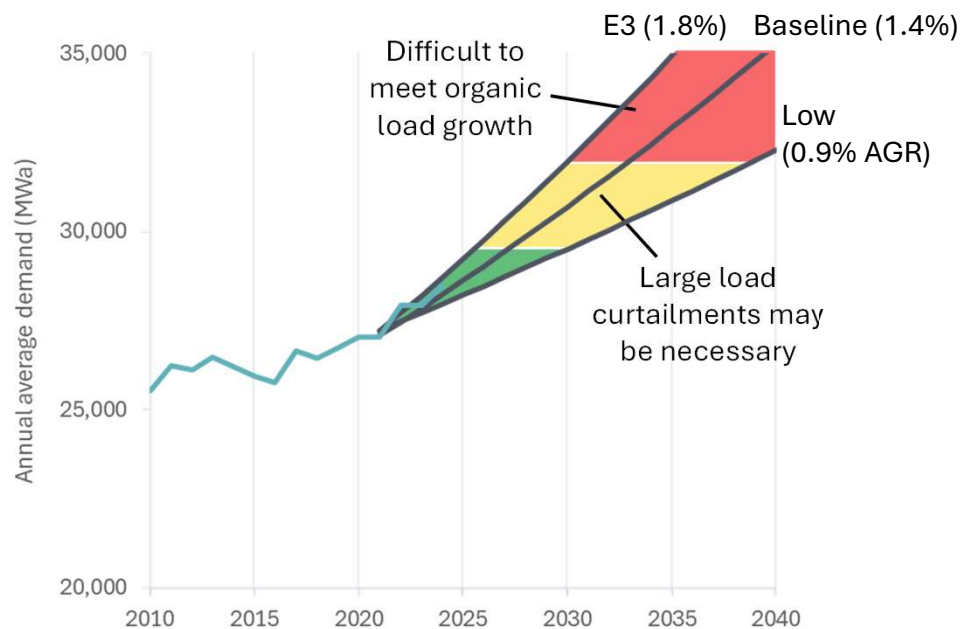
Extrapolated* organic load growth trajectories and resource adequacy challenges



- 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

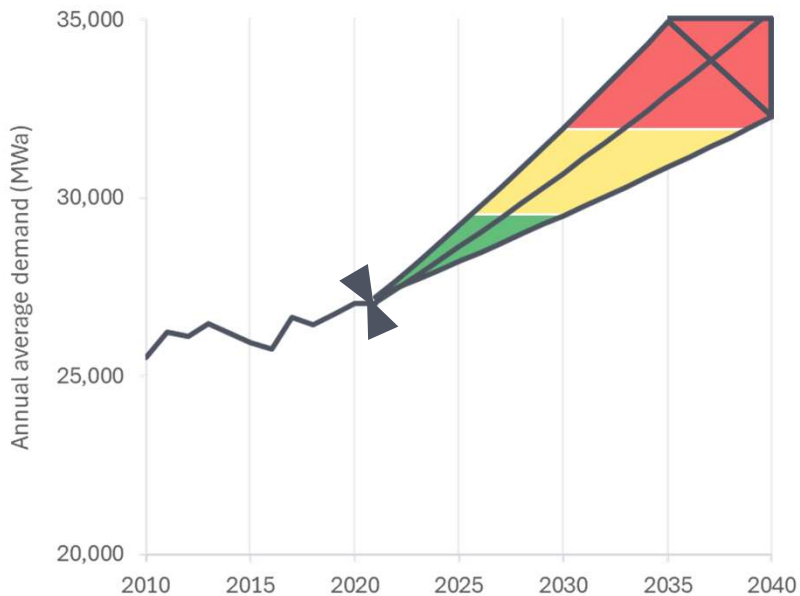
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- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

“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

