RESOURCE ADEQUACY ANALYSIS

CHAPTER SEVEN

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction

The electricity industry in the Pacific Northwest (PNW) is transitioning as governments and system planners implement major decarbonization policies. The sector is retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, Puget Sound Energy (PSE) and other utilities are rethinking how we plan our systems, especially in resource adequacy (RA). As we transition to 100 percent clean energy by 2045, always having enough energy — maintaining resource adequacy — is paramount to ensure customers continue receiving reliable electricity and a smooth transition to a decarbonized system.

Puget Sound Energy contracted with the consulting firm Energy and Environmental Economics (E3) to produce the resource adequacy analysis for this 2023 Electric Progress Report (2023 Electric Report). E3 worked with our data and used their RECAP model to produce the study results. We based the work described in this chapter on the findings of E3's 2021 report, which recommended the following improvements to our resource adequacy modeling:

- Align the treatment of the first hour of loss-of-load events across the scenarios with and without battery storage
- Consider changing climate in evaluating energy demand, hydroelectric generation, and market purchases
- Consider load and renewable correlations. Puget Sound Energy did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future studies, as they could impact resource adequacy for PSE's system.
- Discharge storage at its rated capacity, for its rated duration; does not apply a minimum state of charge to the modeled energy capacity
- Incorporate hydroelectric dispatch capabilities and hydroelectric energy limitations
- Perform GENESYS sensitivity to determine if it would result in an increase in the storage ELCC; PSE did not run this sensitivity. The ELCC of energy storage is very high and there is sufficient energy to charge the energy storage. The GENESYS sensitivity would not add significant value on storage ELCC

Please see the entire docket and public comments on the UTC website.[1] We worked with E3 to meet all the modeling improvements described in the filing.

➔ See Appendix L: Resource Adequacy for more details regarding the filing and PSEs commitments.

Beyond implementing E3's recommendations, the other major change impacting the resource adequacy analysis is PSE's decision to reduce market reliance. In the past, PSE relied on purchases from the short-term wholesale energy markets as a cost-effective strategy to supplement resources to meet demand. This strategy also allowed us to avoid building significant amounts of generation capacity. Although wholesale electricity prices have remained low in recent

[1] utc.wa.gov/casedocket/2021/210220/docsets

years on average, the PNW has experienced periods of high wholesale electricity prices and low short-term market liquidity.

We expect this wholesale market volatility to limit our ability to rely on the market over time. Based on utilities' current plans, several studies discussed in this chapter's market reliance section have projected that the PNW will face a growing capacity shortage over the next decade.[2] Given the tightening of energy markets and to prepare for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce our reliance on short-term wholesale market purchases to zero by 2029.

Peak capacity is the maximum capacity need of a system to meet loads.

Perfect capacity is the firm and reliable capacity required to maintain a chosen reliability metric.

The **planning reserve margin** is the generation resource capacity required to provide a minimum acceptable level of reliable service to customers under peak load conditions.

The **peak capacity credit** assigned to a resource is the effective load-carrying capability (ELCC). This value depends highly on the load characteristics and portfolio resource mix, which makes it unique to each utility; it is expressed as a percent of the equivalent nameplate capacity.

➔ For more information on market reliance, please refer to section four of this chapter.

Considering the projected capacity shortages for the NW region, the Western Power Pool (WPP) created the WRAP to provide a programmatic approach for utilities to work together to ensure resource adequacy throughout the region. The WRAP is the first regional reliability planning and compliance program in PNW history.[3] The Western Resource Adequacy Program is discussed in more detail later in this chapter in section six.

➔ The results of how the WRAP program will impact peak needs are in Chapter Eight: Electric Analysis.

1.1. Incorporating Climate Change

Puget Sound Energy's 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used historical temperatures from the range of temperature variability to create the resource adequacy model. We then iterated through the different temperature years to create hourly load draws that we used in the modeling simulations, but the underlying data did not recognize predicted effects from climate change.

The methodology we used to incorporate climate change in this report is the first step in an evolving process. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. It is essential to consider climate change in resource planning because our customers rely on PSE energy to heat in the winter and stay cool in the summer. With an overall average warming trend, we would expect, on average, less overall heating demand and more cooling demand. We used recently developed regional climate model projections to create

[2] https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf
[3] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

demand draws for the resource adequacy simulation that reflect climate change. We also updated the peak demand forecast, which resulted in normal peak temperatures for summer and winter that increased over time.

➔ Please refer to Chapter Six: Demand Forecast for more details regarding how we incorporated climate change into our demand forecast.

Along with incorporating climate change in the demand forecast, we also updated hydroelectric generation draws. Previously, we used the historical 80-year hydroelectric stream flow data to create a generation forecast based on current operating conditions. The same climate change data we used for the demand forecast also provided stream flow data that we turned into predicted generation for the hydroelectric facilities.

➔ For details regarding the hydroelectric forecast, refer to Chapter Five: Key Analytical Assumptions.

2. Overview of Results

Resource Adequacy measures the ability of generating resources to meet load across a wide range of system conditions, accounting for supply and demand variability. No one can plan a perfectly reliable electrical system; however, we use several reliability metrics in the industry to ensure the system has adequate generation capacity during extreme events. We apply a five percent loss of load probability metric in the resource adequacy study, which means we plan our system to have an expected loss of load event occur once in 20 years. We reflected this in our planning reserve margin in Table 7.1, which shows the 2021 Integrated Resource Plan (IRP) results and the new seasonal analysis we used in this report. Overall, the peak capacity need increased from the 2021 IRP.

Table 7.1: Planning Reserve Margin and Peak Capacity Need — Percent Above Normal and MW Need Above Normal Peak

Study Years and Seasons	2027 Winter (2021 IRP)	2031 Winter (2021 IRP)	2029 Winter (2023)	2029 Summer (2023)	2034 Winter (2023)	2034 Summer (2023)
Planning Reserve Margin (%)	20.7	24.2	23.8	21.2	23.9	26.1
Additional Perfect Capacity Need (MW)	907	1,381	1,272	1,875	1,746	2,856

Table 7.1 shows the additional perfect capacity need comparing the results from the 2021 IRP to the 2023 Electric Report study years. The 2023 Electric Report is the first time we modeled the planning reserve margin for winter and summer. When comparing the results from these two reports, it is important to compare the 2021 IRP study years to the 2023 Electric Report winter results only, as prior IRPs have only evaluated the winter months. When you compare winter results, you see a slight increase in the perfect capacity need from 2027 to the 2029 winter. From this analysis, we found that although PSE is a winter-peaking utility, the additional perfect capacity need is higher in summer. This

high summer need means there are fewer resources available in the summer than in the winter, not that the summer peak is higher than the winter peak.

Table 7.2 compares the 2023 Electric Report and 2021 IRP effective load carrying capability (ELCC) results. The ELCC measures how many megawatts of a resource PSE can plan on to meet the planning reserve margin. We modeled most of the resources with saturation effects; the more resources added of the same location or type, the less effective they are at meeting peak capacity. The results in the table are for the first tranche[4] (the first amount of MW of installed capacity) of each resource — 100 MW for renewable resources and demand response and 250 MW for storage. The ELCC for additional resources declines based on the ELCC saturation results, which we described further in the Key Takeaways section and Appendix L: Resource Adequacy. There is an increase across all renewable resource ELCCs from the 2021 IRP to the 2023 Electric Report. Most significantly, solar and batteries increased due to the seasonal analysis and other modeling changes discussed throughout this chapter in greater detail.

Table 7.2: Effective Load Carrying Capability Results for First 100 MW for Wind and Solar or First 250 MW for Storage

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	47	32	41
Washington	Wind	18	15	13	5
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
Distributed Energy Resources (DER) Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95

[4] Tranche is the capacity segment of a resource on the ELCC saturation curve.

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP (2021 IRP modeled ELCC saturation curves for Washington wind and Washington solar only)
2. 2023 Electric Progress Report

2.1. Key Takeaways

Several elements contributed to the increase in the planning reserve margin:

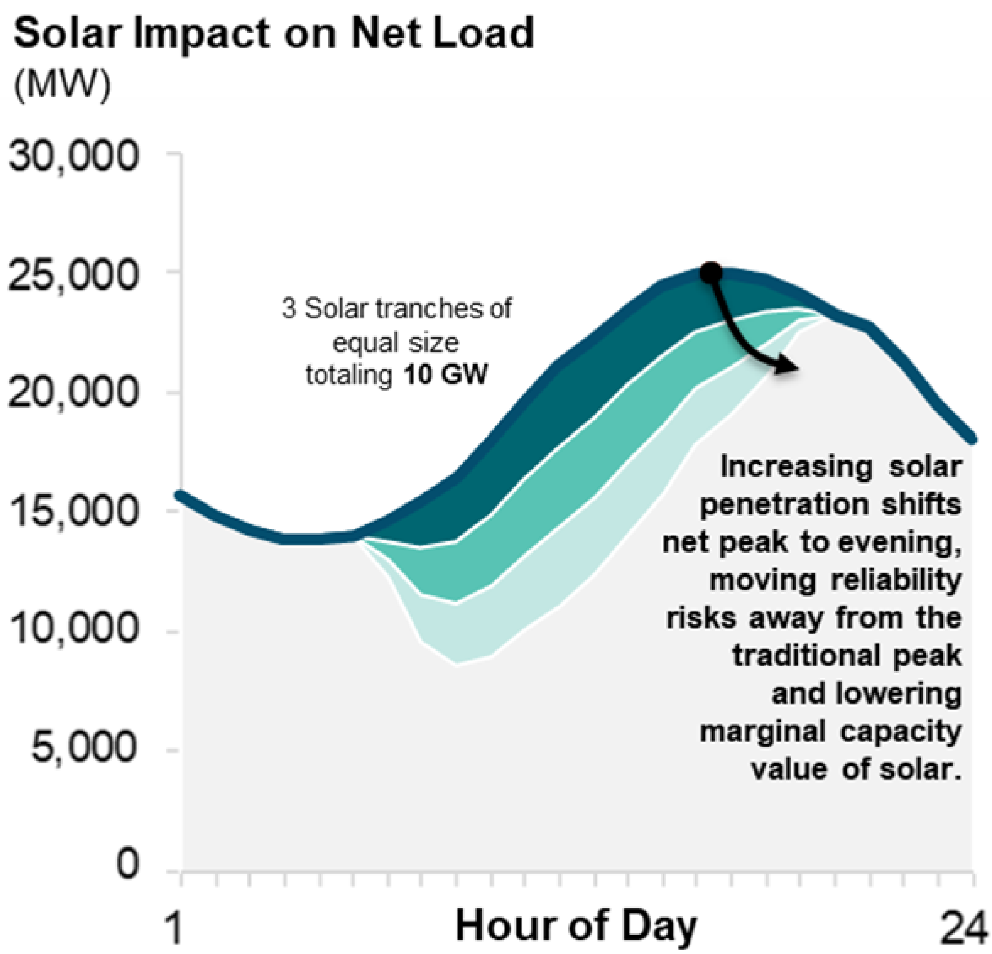
- Including climate change data in the load forecast and peak temperatures slightly lowered the normal winter peak and increased the normal summer peak. Even with the increase in normal summer peak temperatures, the summer peak does not come close to the level of the winter peak through the report's planning horizon.
- Increase in peak demand. Although climate change decreased normal winter loads, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was more significant than the decrease from the climate change data, resulting in an overall increase in peak demand.
- The analysis looked at winter and summer capacity needs.
- The climate change data also showed changes in the duration and frequency of outage events which impacted the results. The data shows a decrease in event duration, less frequent events in the winter, and more frequent events in the summer, increasing the ELCCs for shorter duration storage resources and solar.
- The hydro generation profile changed when we incorporated climate change into the modeling because the historical spring runoff now happens earlier in the year. The earlier spring runoff changes hydropower availability and leaves less water for the summer.

The saturation effect can have a significant impact on resource ELCCs. In the next section, we explain why it was vital to consider saturation when we evaluated the ELCC of a resource.

2.1.1. Effective Load Carrying Capability Saturation Effect

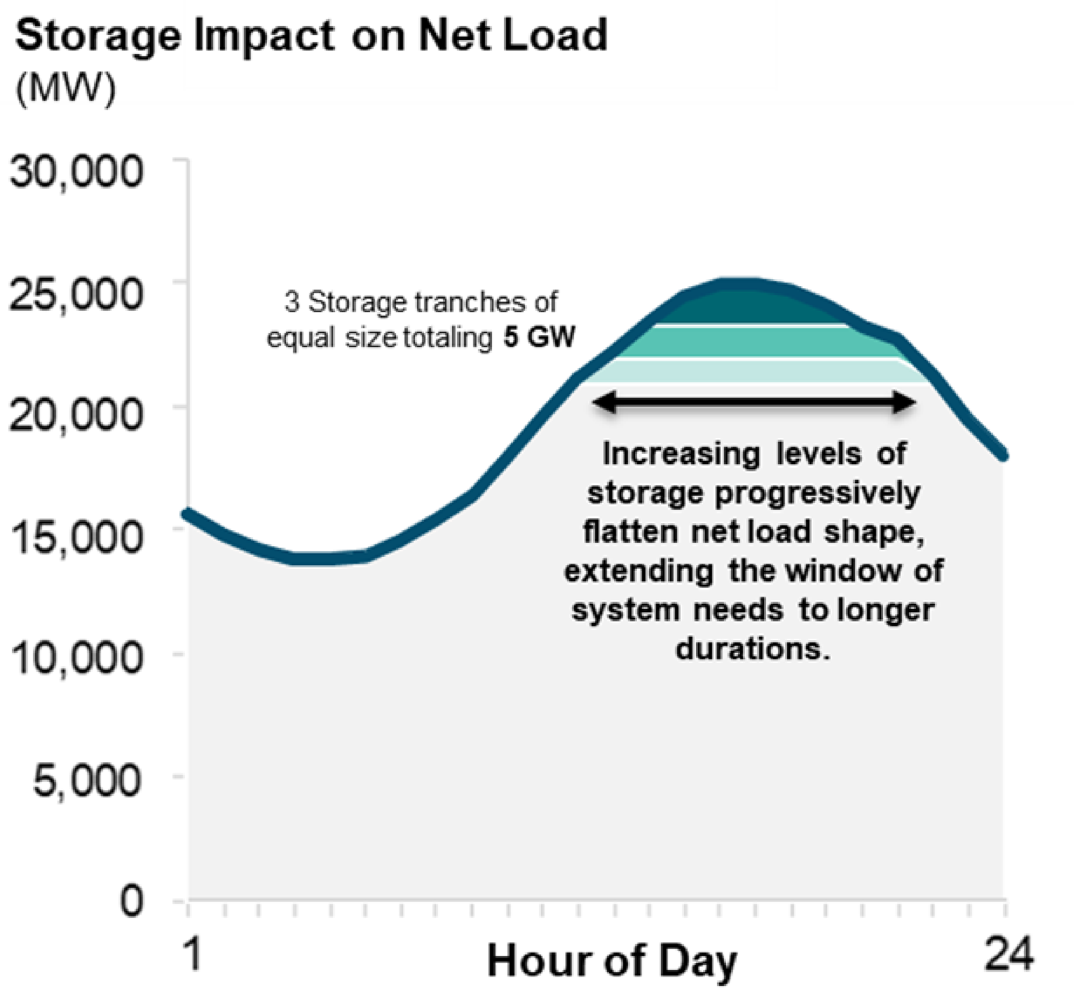
The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. Figure 7.1 shows an example of ELCC saturation — the dynamics for solar on a peak summer day. Note that this is an illustrative example and does not represent PSE's system. The first grouping or tranche of solar produces a lot of energy during peak demand hours, showing a relatively high ELCC. However, when one adds more solar, the net peak demand (load minus renewable generation) shifts into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during the daytime but cannot contribute to the reliability needs at night. Wind resources experience this same saturation effect, except rather than shifting the net load from daytime hours to nighttime hours, wind resources shift the net load from times when wind generation is high to times when wind generation is low.

Figure 7.1: Example of ELCC Saturation Effect for Solar (Does Not Represent PSE's System)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure 7.2 for an example showing storage dynamics on the same peak day. Note that this is an example and does not represent PSE's system.

Figure 7.2: Example of ELCC Saturation Effect for Energy Storage (Does Not Represent PSE's System)



The first tranche of energy storage produces a lot of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as one adds more energy storage, the net peak demand (load minus energy storage generation) flattens and spans a longer period, see Table 7.3. As a result, the ELCC for these later tranches is lower because the storage has already mitigated during the highest peak demand hours but can't contribute the same reliability value longer due to the limited stored energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, in addition to the length of calls but without a need to charge.

Table 7.3: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15

2.2. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This normal peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it is estimated such that there is a 50 percent probability of the true peak load being higher than this forecast and a 50 percent probability of it being lower.

The PRM represents the resource need amount beyond the normal peak load that PSE must maintain one-in-two to satisfy the total resource need and the reliability target of 5 percent loss of load probability (LOLP).

3. Resource Adequacy Analysis Results

This section describes the results of the resource adequacy analysis we prepared for this report. First, we present the capacity credit results for existing and contracted resources, representing how much existing and contracted resources contribute toward satisfying the PRM. Next, we present the total resource need and the PRM. The total resource need represents the capacity needed to satisfy PSE's reliability standard, and the PRM represents this amount relative to the median peak load. Lastly, we present the capacity contribution results for new generic resources.

3.1. Capacity Credit of Existing Portfolio

This section provides the capacity credit for all resources in PSE's portfolio, including hydroelectric, thermal, wind, and solar. This section also shows the capacity credit for other contracts and wholesale market purchases. E3 calculated the ELCC resource values for the three climate models and then averaged the results to get the final ELCC values.

3.1.1. Hydroelectric Resources

Puget Sound Energy owns three hydroelectric plants: Upper Baker, Lower Baker, and Snoqualmie Falls. E3 calculated the ELCC for each resource (see Table 7.4). The summer and winter ELCCs are similar for Upper Baker and Lower Baker. However, Snoqualmie Falls is a run-of-river hydroelectric facility; as a result, the ELCC is lower in summer due to lower summer river flows. The ELCC values in 2034 are like those in 2029.

Table 7.4: Effective Load Carrying Capability for PSE-owned Hydroelectric Resources (MW)

Hydroelectric Resources	Nameplate	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Upper Baker Units 1 and 2	107	70	69	77	79
Lower Baker Units 3 and 4	111	67	66	58	60
Snoqualmie Falls	53	39	39	11	12

We also contract with five Mid-C hydroelectric plants on the Columbia River for power. We calculate the capacity contributions based on the Pacific Northwest Coordination Agreement (PNCA) final regulation (see Table 7.5) for these plants. The capacity contributions are PSE's contractual capacity, less losses, encroachment, and Canadian Entitlement. These capacity contributions are the same for winter and summer.

Table 7.5: Capacity Credit for Mid-C Hydroelectric Resources (MW)

Hydroelectric Resources	2029	2034
Mid-C Rocky Reach	313	313
Mid-C Rock Island	121.2	121.2
Mid-C Wells	115	115
Mid-C Wanapum	6.1	6.1
Mid-C Priest Rapids	5	5

The capacity credit for the Mid-C hydroelectric resources is the same for winter and summer.

3.1.2. Thermal Resources

Puget Sound Energy owns several thermal plants. We calculate the capacity credit based on the plant's rating at different temperature levels (see Table 7.6). In winter, the capacity reflects the capacity rating when operating at an ambient temperature of 23 degrees Fahrenheit. In summer, the capacity reflects the capacity rating when operating at an ambient temperature of 96 degrees Fahrenheit. The efficiency of these thermal plants is lower at higher temperatures. As a result, the summer ratings are lower than the winter ratings.

Table 7.6: Capacity Credit for Thermal Resources (MW)

Thermal Plant	Winter	Summer
Encogen	182	149
Ferndale	266	246
Goldendale	315	268

Thermal Plant	Winter	Summer
Mint Farm	320	270
Sumas	137	117
Frederickson CC	134	104
Fredonia 1	117	91
Fredonia 2	117	91
Fredonia 3	63	46
Fredonia 4	63	46
Whitehorn 2	84	65
Whitehorn 3	84	65
Frederickson 1	84	65
Frederickson 2	84	65

Thermal plants can also have forced outages. Although forced outages do not impact the capacity credit assigned to thermal plants, E3 considered forced outages at these plants to determine the system overall resource need and PRM value The forced outage rates vary for each plant and range from 2.31 percent to 11.3 percent.

3.1.3. Wind and Solar

Puget Sound Energy owns and has contracts for power from several wind and solar projects. These projects include Hopkins Ridge Wind, Wild Horse Wind (including an expansion), Klondike Wind, Lower Snake River Wind, Skookumchuck Wind, Golden Hills Wind, Clearwater Wind, Lund Hill Solar, and Wild Horse Solar. E3 calculated the ELCC for wind and solar resources (see Table 7.7). The ELCC for wind resources is higher in winter (28 percent in 2029) than in summer (14 percent in 2029) because PSE's wind projects, in aggregate, output more energy in the winter. Conversely, the ELCC for solar resources in summer (45 percent in 2029) is higher than in winter (7 percent in 2029) because solar projects output more energy in the summer, and better align with peak demand. The ELCC values in 2034 are like those in 2029.

Table 7.7: Effective Load Carrying Capability for Wind and Solar Resources (MW)

Resources	Nameplate MW	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Wind	1,504	428	421	210	217
Solar	150	10	10	67	69

3.1.4. Other Contracts

In addition to the wind and solar contracts discussed in the proceeding section, PSE has several other contracts. We have a 300 MW power exchange contract with Pacific Gas and Electric Company (PG&E). Under this contract, PG&E must provide PSE with 300 MW of power in winter when needed, and PSE must provide PG&E with 300 MW of power in summer when needed. In addition to this contract, we have a few other small contracts.

➔ A full discussion of the contracts is in Appendix C: Existing Resource Inventory.

See E3's ELCC calculation for these contracts in Table 7.8. The ELCC in summer is negative, which means contracts result in a net increase in the overall resource need when included in the portfolio. The PG&E exchange has the most significant influence because PSE is obligated to send PG&E 300 MW of power in summer when needed, which increases PSE's overall summer resource need. Other contracts partially offset this increase. The ELCC in winter is above 350 MW. The ELCC values in 2034 are like those in 2029.

Table 7.8: Effective Load Carrying Capability for Other Contracts (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Other Contracts	382	376	-179	-185

3.1.5. Market Purchases

In addition to determining the capacity contribution of PSE's resources, E3 also estimated the ELCC of market purchases (see Table 7.9). These market purchases are how much power is available to purchase from the regional market on a short-term basis. We used the Classic GENESYS and the Wholesale Purchase Curtailment Model (WPCM) to determine the availability of market purchases. We have 2,031 MW of transmission from Mid-C to import power via market purchases, but we also use this transmission to deliver power from the Mid-C hydroelectric plants and Wild Horse Wind project.

The ELCCs show that the ELCC for market purchases is lower in summer than in winter. As discussed in Appendix L: Resource Adequacy, GENESYS and the WPCM model show that the PNW has less generation for us to call on in summer than in winter. Moreover, we project that the PNW will have less generation available in summer 2034 than in summer 2029. As a result, the ELCC for summer declines between 2029 and 2034. The ELCC for winter remains similar in 2034.[5]

Table 7.9: Effective Load Carrying Capability for Market Purchases (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Market Purchases	1,440	1,434	961	751

3.2. Total Resource Need and Planning Reserve Margin

E3 quantified the total resource need and PRM necessary to satisfy our five percent of LOLP reliability target (see Table 7.10). E3 first quantified the system's capacity shortfall, representing the additional perfect capacity needed to satisfy the reliability target. The capacity shortfall is higher in summer (1,875 MW in 2029) than in winter (1,272 MW in 2029). Although peak demand is lower in summer, the capacity contribution of resources is much lower in summer. Thermal ratings are lower due to higher ambient temperatures, the ELCC of wind and hydroelectric is lower in summer, the PG&E exchange reduces available capacity, and there are fewer market purchases available in summer.

5 https://www.pse.com/-/media/PDFs/IRP/2023/electric/appendix/21_EPR23_AppL_Final.pdf

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These factors result in a more significant capacity shortfall in summer than in winter. The capacity shortfalls grow in both seasons as the load increases, but there are more in summer due to greater load growth.

E3 then calculated the total resource need. The total resource need is the sum of capacity contributions across all resources plus the additional perfect capacity needed. The total resource need is higher in winter (6,319 MW in 2029) than in summer (5,329 MW in 2029).

Lastly, E3 calculated the PRM. The PRM percentage is similar across seasons and years, ranging from 26 percent to 28 percent. The key factors influencing the PRM are load variability (beyond the median peak load), operating reserve requirements, thermal forced outages, and Mid-C hydroelectric performance (relative to its capacity contribution).

Table 7.10: Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Additional Perfect Capacity Need	1,272	1,746	1,875	2,856
Total Resource Need	6,319	6,771	5,329	6,107
Median Peak Load	5,004	5,382	4,171	4,831
Planning Reserve Margin	26%	26%	28%	26%

In this analysis, we used one-in-two (P50) peak load forecast to calculate the planning reserve margin.

➔ See Appendix L: Resource Adequacy for more details on peak-load forecast.

3.3. Effective Load Carrying Capability for Incremental Resources

E3 evaluated the capacity contribution of incremental resources to PSE's current resource portfolio. These resources reflect a wide range of resource options, including in-state and out-of-state renewable resources, distributed solar resources, energy storage, demand response, hybrid, and thermal resources.

These resources do not represent specific wind or solar projects bid to PSE through a resource procurement. Instead, they are generic resource options that PSE would expect to receive in future procurements. We considered these generic options in our long-term portfolio analysis, and these capacity contribution values serve as inputs to the portfolio selection.

3.3.1. Generic Wind and Solar Resources

E3 calculated the ELCC for eight wind, two distributed solar, and five utility-scale solar resources (see Table 7.11). These ELCC values are the capacity contribution for the first 100 MW of incremental capacity added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in Appendix L.

In general, the ELCC for wind is higher in winter than in summer, and the ELCC for solar is higher in summer — seasonal generation patterns for these resources. The ELCC differs by location, reflecting differences in average generation and the timing of that generation. The ELCC is higher for resources with higher generation levels when PSE's system has a greater capacity need.

➔ See Appendix L: Resource Adequacy for details about the resource groups and saturation curve for the generic resource.

Table 7.11: Effective Load Carrying Capability for Generic Wind and Solar Resources (First 100 MW)

Resource	Resource Type	Winter (%)	Summer (%)
British Columbia	Wind	34	13
Idaho	Wind	1	1
Montana Central	Wind	39	27
Montana East	Wind	32	19
Offshore	Wind	32	41
Washington	Wind	13	5
Wyoming East	Wind	52	34
Wyoming West	Wind	39	34
Distributed Ground Mount	Distributed Solar	4	28
Distributed Rooftop	Distributed Solar	4	28
Idaho	Utility-scale Solar	8	38
Washington East	Utility-scale Solar	4	55
Washington West	Utility-scale Solar	4	53
Wyoming East	Utility-scale Solar	11	29
Wyoming West	Utility-scale Solar	10	28

3.3.2. Generic Energy Storage ELCC Saturation Curves

We asked E3 to model the ELCC of four types of energy storage resources (see Table 7.12). There are three lithium-ion battery storage resources, with two-hour, four-hour, and six-hour durations, and one eight-hour pumped hydroelectric storage resource. The duration metric specifies the amount of time a storage resource can continuously discharge at its rated capacity when fully charged. For example, a fully charged 100 MW Lithium-ion Battery (four-hour) can discharge at 100 MW for four consecutive hours. The roundtrip efficiency metric specifies the amount of energy conserved when charging and discharging a battery. The forced outage rate, like thermal resources, specifies the probability that a storage resource goes on a forced outage.

Table 7.12: Generic Energy Storage Resources

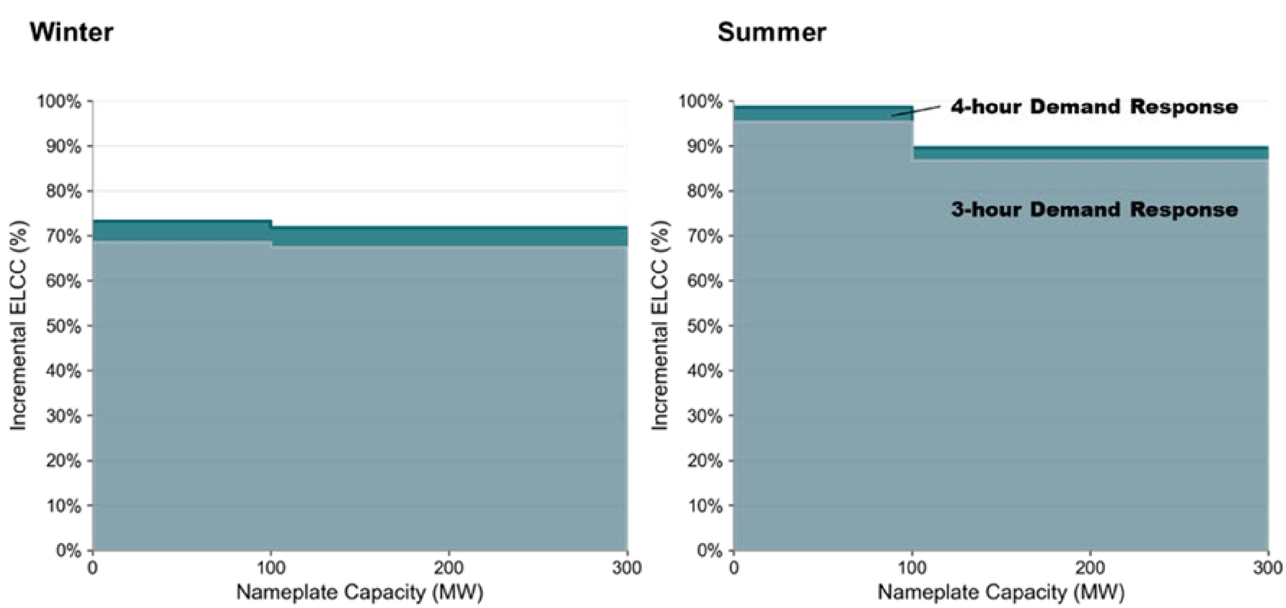
Resources	Technology	Duration	Roundtrip Efficiency (%)	Forced Outage Rate (%)
Lithium-ion Battery (2-hour)	Lithium-ion	2 hours	86	2
Lithium-ion Battery (4-hour)	Lithium-ion	4 hours	87	2
Lithium-ion Battery (6-hour)	Lithium-ion	6 hours	88	2
Pumped Storage (8-hour)	Pumped hydroelectric storage	8 hours	80	1

3.3.3. Generic Demand Response ELCC Saturation Curves

E3 calculated the ELCC saturation curves for two types of generic demand response programs: one with maximum three-hour call durations and another with maximum four-hour call durations (see Figure 7.3). E3 calculated two tranches for demand response: 0–100 MW and 100–300 MW. For both programs, we limited the number of calls to 10 in winter and 10 in summer. Also, PSE cannot call the same demand response program more than once in six hours.

As for storage, the ELCC of demand response diminishes with increasing penetration as the limited duration becomes less effective at addressing PSE's reliability needs at higher penetration levels. The ELCC for demand response is lower in winter than in summer because the duration of loss of load events is longer.

Figure 7.3: Effective Load Carrying Capability Saturation Curves for Demand Response Resources



3.3.4. Generic Hybrid Resources

PSE directed E3 to model the ELCC of four types of hybrid resources (see Table 7.13). We assumed that these hybrid resources would be in Washington State. The solar resource is Washington East Solar, the wind resource is Washington Wind, and the storage resource is Lithium-ion Battery Storage (four-hour). For each hybrid resource, we assumed that the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the capacity of the storage, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce overall costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Table 7.13: Generic Hybrid Resources

Resources	Interconnection MW	Solar MW	Wind MW	Storage MW
Solar + Storage	100	100	-	50
Solar + Storage (Restricted Charging)	100	100	-	50
Wind + Storage	100	-	100	50
Solar + Wind + Storage	200	100	100	50

3.3.5. Generic Thermal Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic thermal resources (see Table 7.14). Three factors influence the capacity contribution of these resources: ambient temperature efficiency ratings, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing thermal plants. The summer rating is lower than the winter rating for combined cycle combustion turbine and frame combustion turbine units. The reciprocating internal combustion engines have the same efficiency ratings in the summer and winter.

Table 7.14: Effective Load Carrying Capability for Generic Natural Gas Resources

Resource	Nameplate Winter (MW)	ELCC Winter (%)	Nameplate Summer (MW)	ELCC Summer (%)
Combined Cycle	367	84	310	92
Frame Turbine	237	96	184	98
Reciprocating Engine	18	96	18	96

4. Market Risk Assessment

Puget Sound Energy has relied on short-term market resources to fill less than 1,500 MW of transmission capacity for more than 15 years. The total firm transmission contracts are 2,030 MW to Mid-C; we then subtract the transmission needed for resources at the Mid-C, which comes to less than 1,500 MW of available transmission left for short-term market purchases. See Appendix C: Existing Resource Inventory for the breakdown of transmission contracts. Relying on the surplus capacity of others in the region was a reasonable strategy when the region had significant surplus peak capacity. Experts predict the region soon will have no significant surplus peak capacity. They expect the region will be short of physical capacity, even under very conservative assumptions. Continuing to rely on short-term market purchases creates physical and financial risks for PSE's customers and shareholders. We need to adapt to changing market conditions.

4.1. Reduce Market Reliance

Due to the growing regional concerns about capacity in the short-term market and our interest in joining the WRAP, we will phase out reliance on short-term market purchases as we make plans to ramp into the WRAP. We reduced market reliance by more than 200 MW per year starting in 2024 and reached zero reliance by 2029 in this report.

Table 7.15 shows the ELCC adjustment to market reliance from E3's models but is not the final market reliance we used in the capacity expansion modeling described in Chapter Eight: Electric Analysis. We phased the market reliance for peak capacity down over time reaching zero by 2029.

Table 7.15: Effective Load Carrying Capability Adjusted MW of Market Reliance from E3 Model

Adjustment	Nameplate	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Transmission Capacity	2,030	2,030	2,030	2,030	2,030
Resources at Mid-C	(512)	(512)	(512)	(512)	(512)
ELCC Adjustments	0	(78)	(557)	(84)	(767)
Total Available Transmission	1,518	1,440	961	1,434	751

4.2. Changing Regional Resource Adequacy

Numerous studies and articles highlight regional resource adequacy concerns. Three respected industry-based organizations periodically issue studies about resource adequacy in the Northwest and have recently raised critical concerns. The North American Electric Reliability Corporation (NERC)[6] studies regional entities and assessment areas, including WECC-NWPP-US & RMRG (Western Interconnection, Northwest Power Pool, and Rocky Mountain Reserve Sharing Group). The Western Electricity Coordinating Council (WECC)[7] evaluates resource adequacy across the entire western interconnection (WECC) and within five subregions, including NWPP-Northwest. The Pacific Northwest Utilities Conference Committee (PNUCC)[8] covers the Northwest regional planning area. All three organization's reports cover a ten-year horizon. Across the West, utilities plan to retire nearly 26 GW coal and natural gas resources over the next decade. Each of their most recent reports concluded that demand and resource variability is increasing rapidly, creating challenges for the bulk power system to provide reliable supply in the near

[6] 2021 Long-term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[7] 2021 Western Assessment of Resource Adequacy" ("WARA"), https://www.wecc.org/Administrative/WARA%202021.pdf

[8] 2022 Northwest Regional Forecast, https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf

term. The WECC put it most directly, stating, "As early as 2025, all subregions (of the WECC) will be unable to maintain 99.98 percent reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power."[7] The PNUCC concluded, "The annual energy picture reveals a regional resource deficit by next year (2023), which is three years earlier than last year's estimate."[8] And NERC determined, "The two largest U.S. assessment areas in the Western Interconnection — California/Mexico and the Northwest-Rocky Mountain — have the potential for high load-loss hours and energy shortfalls for 2022 and beyond."[6]

While each organization approached the analysis using its own assumptions and methodologies, some common themes emerge on what is driving the increase in variability:

- Government policies and consumer sentiment are accelerating the move to clean energy
- More frequent and extreme weather events due to climate change
- Retirement of baseload resources and the addition of variable energy resources

Traditional resource adequacy approaches have been based solely on capacity, which worked well when most generation assets were dispatchable and demand was more predictable. The peak capacity shortfall typically occurred during the annual peak capacity hour. In today's climate, however, the drivers affecting the generation and load variability can lead to critical capacity shortfalls that do not coincide with peak demand. Focusing only on capacity fails to account for this variability fully. The PNUCC Northwest Regional Forecast (NRF) is the best source for detailed information on this topic.

$$
\begin{aligned}
&NRF\\
&= \sum(\textit{Utility loads with planning reserve margin})\\
&- (\textit{resource forecasts for those owned \& contracted by utilities})\\
&+ (\textit{resource, conservation, demand response additions based on their IRPs})
\end{aligned}
$$

Table 7.16 shows that even with very conservative adjustments to the NRF, we expect the region to be significantly short in the winter of 2029 and extremely short of capacity in the summer of 2029. We made two adjustments to the winter for the following factors:

- Independent Power Purchaser (IPP) Generation: PSE's market survey shows 1,697 MW of IPP resources available today. It may not be reasonable to assume those resources will be uncontracted as the region considers entering the WRAP, but we included those here to be conservative.
- Southwest Imports: The Northwest Power and Conservation Council's Classic GENESYS model assumed 3,400 MW of imports from California would be available to the Pacific Northwest. As California electrifies transportation and buildings, those imports may not be available. We included them in this table to ensure a conservative perspective.

Table 7.16: Adjusted NRF Table Regional Capacity Short Position (MW)

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
PNUCC — Regional NRF Short	4,830	5,240	6,060	5,950

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Identified Available Firm Resources in the Region (Operational)	1,700	-	1,700	-
California Imports	3,400	-	3,400	-
Net Regional Shortage	(270)	5,240	960	5,950

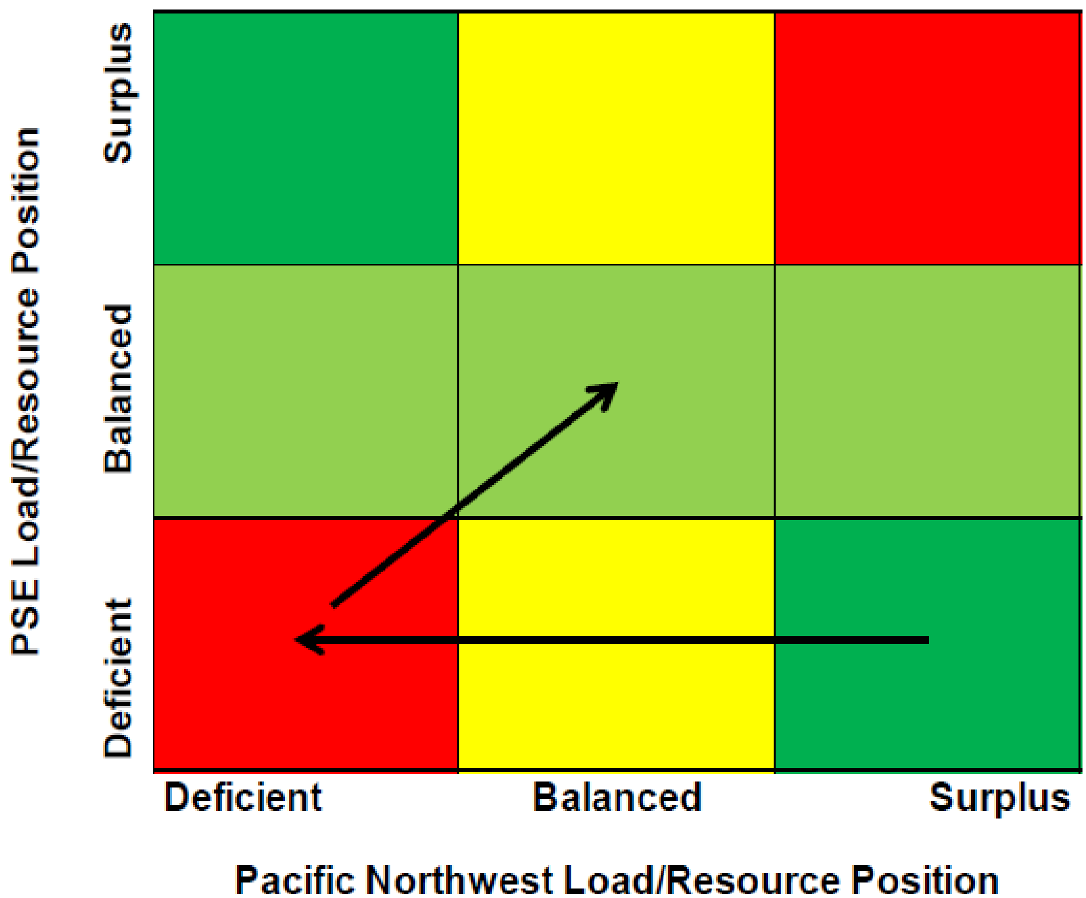
Note: PNUCC data not provided past 2031. PNUCC numbers for 2033 provided from the latest year available.

Table 7.16 highlights that the region will be short on peak capacity even with questionable assumptions on IPP resources and California imports.

4.3. Change Strategic Position

The risk matrix shown in Figure 7.4.provides an illustration of capacity position risk. When the region is surplus, it is prudent for PSE to be physically short — as illustrated by the box in Figure 7.4 with an 'X' below. In that scenario, we manage the financial risk, but we did not have to build unnecessary physical generation capacity. However, as the region grows short of capacity, PSE would shift to the 'Y' box, creating a physical and financial risk. Even if we can hedge the financial risk of relying on short-term market capacity resources, the physical reliability risk may not be manageable. We may not need to build resources to fill that entire market position, though. Puget Sound Energy could sign longer-term contracts to fill this position, if these options are available and do not leave the position to the short-term market. We must move to at least the balanced position in Figure 7.4 for our resource adequacy position going forward.

Figure 7.4: Capacity Position Risk Matrix



4.4. Market Reliance

The 2023 Electric Report reduces our reliance on the short-term market, eventually bringing market reliance to zero by 2029, as reflected in Table 7.17.

Table 7.17: Perfect Capacity Adjusted to Eliminate Short-Term Market Reliance (MW)

Resource	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Mid-C Hydro	560	560	560	560
Thermal	2,050	1,688	2,050	1,688
All other resources	997	244	981	252
Short-term Market Purchases	-	-	-	-
Additional perfect capacity for 5% LOLP	2,712	2,836	3,180	3,607
Total Resources	6,319	5,329	6,771	6,107

5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs modeled in the AURORA database to perform long-term expansion planning and hourly dispatch. The long-term capacity expansion (LTCE) and hourly dispatch optimize new builds and mimic the hourly operation of the existing resources and new builds. New to the 2023 Electric Report is the winter and summer planning reserve margin. We included only the winter planning reserve in the AURORA model in previous IRPs. Starting with the additional perfect capacity for 5 percent LOLP provided by E3, we made minor adjustments to consider more current assumptions for existing resources' ELCC contribution and to eliminate short-term market reliance. We used the resulting seasonal PRM as an input to the AURORA model to serve as a target in the long-term capacity expansion when determining new resource alternatives.

Seasonal resource ELCCs are also new in the 2023 Electric Report and reflect existing and new resources in the AURORA model. In addition, the renewable resource and storage ELCC saturation effect represented by multiple tranches added model complexity and increased run-time significantly. AURORA evaluates new resources for each of the available builds for the year, so the model ends up with a large matrix of all the resource options and costs, contributing to the long run time. A review of the AURORA model study log shows that storage scheduling also contributes to the extended run time. To manage the large-scale optimization problem run-time and meet the IRP study needs, we adjusted new resource ELCCs, consolidating from six tranches to three.

➔ See Appendix L: Resource Adequacy for additional information on new resource ELCC aggregation.

6. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP)[9] is a compliance-based framework designed to increase regional reliability at a reduced cost for participants. The Western Power Pool (WPP) and a steering committee comprised of western region market participants have proposed a design for a capacity-based RA program. This voluntary program

9 https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

establishes a standardized way to approach the resource adequacy problem across twenty-six regional entities (participants) in the west, with an estimated combined peak load of 65,000 MW.

The WPP conducted an extensive public outreach process over the past few years to create a governance structure to give interested parties a voice in decision-making. Each entity conducts its regional planning and procurement to meet capacity RA. Each Load Responsible Entity (LRE) has its methods for calculating peak load, generation and transmission requirements, and capacity contribution. The LRE management approves new resources, which regulators regulate relative only to that LRE's need. Without transparency and coordination, LREs collectively may rely on market purchases relative to available capacity. Additionally, in the absence of regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of participants within the footprint during capacity critical hours (CCH).

The individualized nature of the current planning framework can make it difficult for regulators, board members, interested parties, and utilities to understand whether, where, and when the region needs new capacity. The WRAP will increase visibility in the region's resources and transmission and help participants coordinate to fill these gaps collectively as they plan for the future.

The main components of the WRAP compliance framework are the forward showing program (FS) and the operational program (Ops Program) for both winter and summer seasons. These programs seek to balance reasonably conservative planning and the flexibility to protect customers from unreasonable costs.

The FS program establishes regional metrics for various resources' footprint and qualifying capacity contribution (QCC) values, sets deliverability expectations, and determines planning windows for demonstrating adequacy. Participants are required to show that they have contracted for the necessary amount of capacity resources to meet a P50 event plus a PRM. Participants must also demonstrate they have firm transmission rights to deliver at least 75 percent of their FS resources. The FS deadline for demonstrating adequate capacity and transmission is seven months before the beginning of each summer or winter season. The first binding season that a participant may elect is summer 2025. Participants must commit to go binding by summer 2028 to continue in the program.

The Ops program creates a framework to provide participants with pre-arranged access to capacity resources in the program footprint when a Participant is experiencing an extreme event, such as excess load or forced outages.

A key benefit of the WRAP is the ability to leverage the region's load and resource diversity so LREs can carry less PRM during the FS planning window than they would on a stand-alone basis. The Ops program allows participants to collectively manage the risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

6.1. Planning Reserve Margin and Effective Load Carrying Capability

We ran a WRAP sensitivity analysis to see how the portfolio for this report would change if we used the WRAP metrics instead of the resource adequacy metrics we developed with E3.

➔ See Appendix L: Resource Adequacy for details regarding the methodology and approach the WPP used.

Table 7.18 WRAP Provided PSE Capacity Need (MW) 2029

Sensitivity	Winter 2029	Summer 2029
One-in-two Peak	4,570	3,447
PSE Planning Reserve Margin	21%[a]	14%[a]
Balancing Reserves	132	122
Less Existing Resources	(3,120)	(2,343)

Note:
a. WRAP PRM percent is an estimate.

Table 7.18 shows the estimated seasonal planning reserve margin and peak capacity shortfall in 2029. Additional resources will fill the peak capacity needs. Table 7.19 shows the resources seasonal peak capacity contribution, by ELCC. The WRAP footprint is split into two solar ELCC zones and 5 wind ELCC zones. The generic solar resources are in Zone Solar VER 1, which contains Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Generic wind resources are distributed in 5 wind zones as shown in Table 7.19.

Table 7.19 WRAP Provided ELCCs for 2029

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
British Columbia Wind	25%	20%	Wind VER 5
Idaho Wind	31%	17%	Wind VER 2
Montana Central Wind	27%	13%	Wind VER 3
Montana East Wind	27%	13%	Wind VER 3
Offshore Wind* (E3's number)	31%	17%	Wind VER 2
Washington Wind	10%	18%	Wind VER 1
Wyoming East Wind	31%	15%	Wind VER 4
Wyoming West Wind	31%	15%	Wind VER 4
DER Ground Mount Solar	3%	23%	Solar VER 1
DER Rooftop Solar	3%	23%	Solar VER 1
Idaho Solar	3%	23%	Solar VER 1
Washington East Solar	3%	23%	Solar VER 1
Washington West Solar	3%	23%	Solar VER 1
Wyoming East Solar	3%	23%	Solar VER 1
Wyoming West Solar	3%	23%	Solar VER 1
Pump Storage	100%	100%	N/A
Nuclear	99%	99%	N/A
Li-ion Battery (2-hour)	40%	40%	N/A
Li-ion Battery (4-hour)	80%	80%	N/A
Li-ion Battery (6-hour)	100%	100%	N/A

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
100 MW Washington Solar East Solar + 50 MW 4-hour Li-ion Battery	43 MW	63 MW	N/A
100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	50 MW	58 MW	N/A
100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	5 54MW	81 MW	N/A
200 MW Montana Wind Central + 100 MW 8-hour PHES	154 MW	126 MW	N/A
Frame Turbine	100%	91%	N/A
Reciprocating Engine	N/A	N/A	N/A
Combined Cycle	86%	80%	N/A