EXH. KCS-3
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: KYLE C. STEWART

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-22____ Docket UG-22____

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF

KYLE C. STEWART

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

7 Resource Adequacy Analysis

This appendix provides an overview of PSE's resource adequacy modeling framework and how it aligns with other regional resource adequacy analyses.

7 Resource Adequacy Analysis

Contents

1. OVERVIEW

The energy supply industry is in a state of transition as major decarbonization policies are implemented in most states. Significant amounts of coal-fired generation is being retired, and new intermittent, renewable generation is being constructed. These changes will cause PSE and other utilities to significantly change how they plan, especially with regard to resource adequacy. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. The detailed design phase of the resource adequacy program is under way, with completion expected in mid-2021. As more details are understood, PSE will begin the evaluation of various resource adequacy elements in the resource adequacy analysis included in the 2021 IRP. At this time, the regional resource adequacy program has not been contemplated or included in the analysis described in this chapter.

In the past, relying on short-term wholesale energy markets has been a very cost-effective strategy for customers. This strategy also avoided building significant amounts of new baseload natural gas generation that might have created significant stranded cost concerns under the new policies. Recent experience shows that while wholesale electricity prices remain low, on average, in the Pacific Northwest (PNW), the region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

In addition to the resource adequacy analysis, PSE has a completed a market risk assessment which evaluates the availability of short-term market purchases for peak capacity. It is important that PSE continue to closely monitor the region’s projected winter and summer season load/resource balance and any changes in the liquidity of the short-term market, and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

2. 2021 IRP RESOURCE ADEQUACY ANALYSIS

Resource adequacy planning is used to ensure that all of PSE customer's load obligations are reliably met by building sufficient generating capacity, or acquiring sufficient capacity through contracts, to be able to meet customer demand with appropriate planning margins and operating reserves. The planning margin and operating reserves refer to capacity above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events with minimal interruption of service. Unexpected events can be variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Reliability requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

The physical characteristics of the electric grid are very complex, so for planning purposes, a 5 percent loss of load probability (LOLP) reliability metric is used to assess the physical resource adequacy risk. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulations. Therefore, the likelihood of capacity being lower than load at any time in the year cannot exceed 5 percent. The 5 percent LOLP is consistent with the resource adequacy metric used by the Northwest Power and Conservation Council (NPCC).

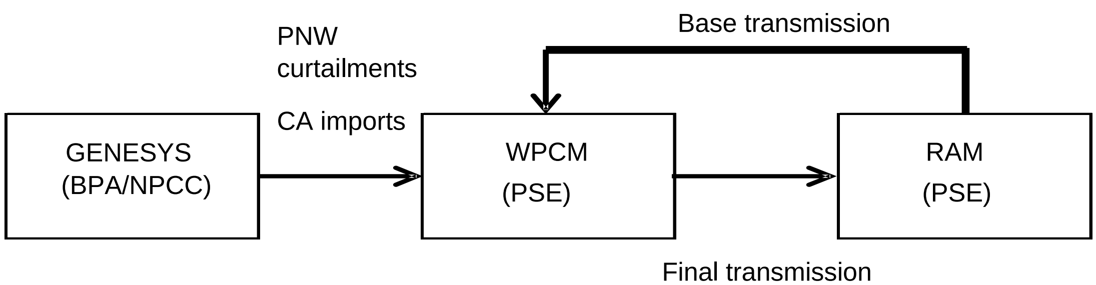
Quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity or ELCC) is an important part of the analysis. The ELCC of a resource represents the peak capacity credit assigned to that resource. It is calculated in the resource adequacy model since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

Resource Adequacy Modeling Approach

PSE's Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE's power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the GENESYS model developed by the NPCC and BPA, which analyzes regional level load/resource conditions, and 2) the Wholesale Purchase Curtailment Model (WPCM), developed by PSE, which analyzes the specific effects of regional curtailments on PSE's system. This allows us to evaluate PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

Figure 7-1 illustrates how the inputs and outputs of these models were linked. The outputs of the GENESYS Model provide inputs for both the WPCM model and the RAM/LOLP model. The RAM/LOLP model and WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 7-1: Market Reliability Analysis Modeling Tools



The GENESYS Model

The GENESYS model was developed by the NPCC and the Bonneville Power Administration (BPA) to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions, and as of the 2023 assessment, 88 years of temperature conditions. For the 2021 IRP, PSE started with the GENESYS model from the NPCC power supply adequacy assessment for 2023. When combined with thermal plant forced outages, the mean expected time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW's overall hourly capacity surplus or deficit in 7,040 multi-scenario "simulations." Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[1]

1 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.

Since the GENESYS model was set for a 2023 assessment, PSE made some updates to capture regional load/resource changes in order to run the model for the years 2027 and 2031. The updates that PSE made to the GENESYS model include:

1. Updated coal plant retirements with retirement years listed in Figure 7-2.

Figure 7-2: Coal Plant Retirements Modeled

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3 & 4	2025

2. Increased the year 2023 demand forecast using the escalation rate of 0.3 percent to the year 2027 and 2031. The escalation rate is from the NPCC demand growth after conservation.
3. Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW).

PSE did not include any other adjustments to GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from NPCC already built into the model.

The Wholesale Purchase Curtailment Model (WPCM)

During a PNW-wide load-curtailment event, there is not enough physical power supply available in the region (including available imports from California) for the utilities of the region to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, PSE developed the WPCM as part of the 2015 IRP. The WPCM links regional events to their specific impacts on PSE's system and on PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase. Therefore, the WPCM first assembles load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events. For this analysis, PSE used the capacity data contained in BPA's *2018 Pacific Northwest Loads and Resources Study*, the latest BPA study available at the time this resource adequacy analysis was completed. Due to the pandemic, BPA's 2019 study was delayed and not available for this analysis.

BPA Loads and Resources Study for 2020–2029

BPA published its *2018 Pacific Northwest Loads and Resources Study* in April 2019. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region.

The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads.

- For 2023, the BPA study forecasts an overall regional winter peak load deficiency of 3,056 MW.
- When BPA's 2023 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 3,056 MW capacity deficit noted above would change to a 344 MW surplus.
- Looking forward to 2029 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2020 winter season peak load deficit of approximately 246 MW to a peak load deficit of approximately 4,891 MW in 2029.
- When BPA's 2029 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in its RAM – the region would transition from a 2020 winter capacity surplus of 3,054 MW to a peak load deficit of approximately 1,491 MW by 2029.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2023. The BPA forecast indicates, as does the Pacific Northwest Utilities Conference Committee (PNUCC) study, that the PNW may experience larger winter capacity deficits over time.

> > > BPA's *2018 Pacific Northwest Loads and Resources Study* can be found at: https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

In October 2020, BPA published its *2019 Pacific Northwest Loads and Resources Study*. The study was completed after PSE finalized this resource adequacy analysis, so updated 2019 information could not be incorporated. PSE is reviewing the 2019 BPA study to assess its implications for the analysis.

Allocation Methodology

The WPCM then uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases. In essence, on an hourly basis, the WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases. In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the LOLP portion of RAM.

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.

SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

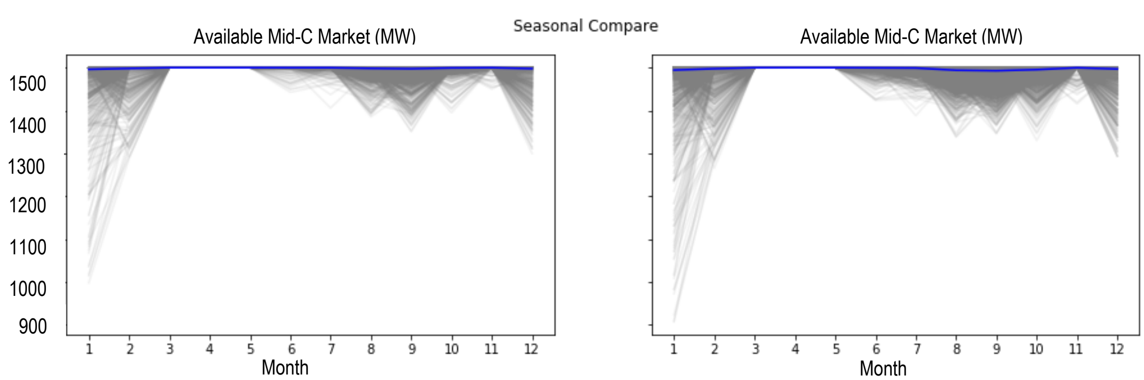
WPCM Outputs

For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-Columbia (Mid-C) transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.

Figure 7-3 shows the results of the WPCM. The charts illustrate the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 7-3: Reduction to Available Mid-C Market



In addition to the WPCM results that are included in PSE's resource adequacy analysis, PSE also conducted a separate market risk assessment. That assessment is described later in this chapter.

The Resource Adequacy Model (RAM)

PSE's probabilistic Resource Adequacy Model enables PSE to assess the following.

1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves over time
2. To establish peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (its effective load carrying capacity, or ELCC)

The RAM allows for the calculation of the following risk metrics.

- **Loss of load probability (LOLP)**, which measures the *likelihood of a load curtailment event occurring* in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s).
- **Expected unserved energy (EUE)**, which measures outage magnitude in MWh and is the *sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations.*
- **Loss of load hours (LOLH)**, which measures outage duration and is *the sum of the hours with load curtailments divided by the number of simulations*.
- **Loss of load expectation (LOLE)**, which measures the *average number of days per year with loss of load* due to system load exceeding available generating capacity.
- **Loss of load events (LOLEV)**, which measures the *average number of loss of load events per year*, of any duration or magnitude, due to system load exceeding available generating capacity.

Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these five risk metrics, once a planning standard has been established.

3. CONSISTENCY WITH REGIONAL RESOURCE ADEQUACY ASSESSMENTS

PSE's reliance on market purchases requires that our resource adequacy modeling also reflect regional adequacy conditions, so consistency with the NPCC's regional GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM.

PSE's RAM operates much like the GENESYS model. Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 7,040 individual simulations; the result of each simulation is PSE's hourly capacity surplus or deficiency. The LOLP, EUE and LOLH for the PSE system are then computed across the 7,040 simulations.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 7,040 simulations made in the NPCC's GENESYS model in terms of temperature and hydro conditions.

The existing resources used by PSE included in this analysis are Mid-Columbia purchase contracts and western Washington hydroelectric resources, several natural gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. Since Colstrip must be out of PSE's portfolio by 2026, it was assumed to retire on 12/31/2025 and was not included as a resource in either GENESYS or RAM.

7 Resource Adequacy Analysis

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Forced outage refers to a generator failure event, including the time required to complete the repair. The "Frequency Duration" outage method in AURORA is used to model unplanned outages (forced outage) for thermal plants. The Frequency Duration outage method allows units to fail or return to service at any time-step within the simulation, not just at the beginning of a month or a day. The method will employ all or nothing outages for most outages but will use partial outages at the beginning and end of the outage period. The logic considers each unit's forced outage rate and mean repair time. When the unit has a planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not included in the forced outage rate.

2. **HOURLY SYSTEM LOADS**. Hourly system loads are modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 88 temperature years. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2016 is represented in the 88 demand draws. Since the resource adequacy model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. Additionally, the model examines adequacy in each hour of a given future year; therefore, the model inputs are scaled to hourly demand using the hourly demand model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. **WHOLESALE MARKET PURCHASES.** These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained above. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM. The initial set of hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights is computed as the difference between

PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports was reduced on the hours when a PNW load-curtailment event is identified in the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

5. **WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.[2] Wind speed data was collected from numerous sites within a prescribed radius around a region of interest. Wind speed data was processed with a heuristic wind production model to generate hundreds of possible generation profiles. The 250 profiles which aligned most closely with the average seasonal production of the site, as determined by the average of the entire data set, were selected for use in the RAM. The profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database[3] and processed with the NREL System Advisory Model to generate production profiles. The 250 solar profiles which were most closely aligned with the annual average production, as determined by the annual average of the entire data set, were selected for use in the RAM. The solar profiles were correlated by measurement year.

Construction risk is not directly incorporated in the resource adequacy model. Permitting and construction times are accounted for in the first year that a new resource is available. For example, if a resource takes four years for permitting and construction, and the IRP planning horizon starts in 2022, the new resource would be available in the year 2026. A full discussion of construction and permitting lead times is available in Appendix D.

2 / *https://www.nrel.gov/grid/wind-toolkit.html*
3 / *https://nsrdb.nrel.gov/*

4. OPERATING RESERVES AND PLANNING MARGIN

Operating Reserves

North American Electric Reliability Council (NERC) standards require that utilities maintain "capacity reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool (NWPP), therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves.

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA).

In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60 minutes, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power or curtailing load. The RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, should a forced outage at one of PSE's generating plants cause loads to exceed available resources.

BALANCING AND REGULATING RESERVES. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts versus real-time values for load, wind and solar generation. The first study was for the year 2025 and includes PSE's current portfolio plus new renewable resources. The second study is for the year 2030 and includes PSE's current portfolio plus generic wind and solar resources to meet the 80 percent renewable requirement. Figure 7-4 below is a summary of the flex up and flex down requirement given the renewable resources that PSE will balance. By 2030, PSE's balancing reserve requirements will significantly increase with the large increase in intermittent renewable resources. The increase in balancing reserves will increase the need for flexible capacity resources. This analysis was based on the results from the 2019 IRP Process, where PSE estimated that it will balance almost 2,400 MW of wind and 1,400 MW of solar by 2030 to meet CETA goals. These results are in alignment with the 2021 IRP process.

Figure 7-4: Balancing Reserve Requirements

Case	Capacity of PSE-balanced Wind (MW)	Capacity of PSE-balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 Case	875	-	141	146	190	196
2030 Case	2,375	1,400	492	503	695	749

This table is a summary of the flexible ramp requirements. RAM uses for the hourly flex up and flex down requirements for each study year.

Planning Margin

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin is defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of reliable service to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

> Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics such as the likelihood (i.e., LOLP), magnitude (i.e., EUE) and duration (i.e., LOLH) of supply-driven customer outages. Those metrics can then be used to quantify the relative capacity contributions of different resource types towards meeting PSE's firm peak loads. These include thermal resources, variable-energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

In this IRP, PSE continues to utilize the LOLP metric to determine its capacity planning margin and establishes the 5 percent LOLP level used by the NPCC as adequate for the region. This value is obtained by running the 7,040 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using "perfect" capacity, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

5. 2021 IRP RAM INPUT UPDATES

The following key updates to the RAM inputs were made since the 2019 IRP Progress Report:

1. The load forecast was updated to reflect the 2021 IRP demand forecast assumptions.
2. The hourly draws of the existing PSE wind fleet and new wind resources were based on NREL wind data set of 250 stochastic simulations.
3. The hourly draws of existing PSE solar resources and new solar resources were based on NREL solar data set of 250 stochastic simulations.
4. Colstrip Units 3 & 4 and Centralia were removed.
5. New resources from the 2018 RFP were added.
6. The balancing reserve requirements were updated to include new results for study years 2025 and 2030.

YEARS MODELED. The 2021 IRP time horizon starts in 2022, so PSE modeled a 5-year and 10-year resource adequacy assessment. The first assessment is the 5-year assessment for the period of October 2027 – September 2028. The second assessment is the 10-year assessment for the period of October 2031 – September 2032. The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the NPCC's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

PSE also updated the 2023 forecasts from the 2018 NPCC Resource Adequacy Assessment in the RAM model. Since PSE is modeling the years 2027 and 2031, the GENESYS model was updated from the year 2023 to match the years 2027 and 2031. This was done by updating the demand forecast using the Council's demand escalation, updating plant retirements such as Colstrip and Centralia, and including new resources from PSE's portfolio (Skookumchuck and Lund Hill). The detailed updates were discussed earlier in this chapter.

RAM is an annual model. It is run for all hours of the year studied. All of the loss of load events are then added up for the year and accounted for in the annual modeling process. The model is set up to track annual events to a planning margin that is applied at the system peak. Monthly or seasonal RAM metrics are not available for this IRP but are being considered for the next IRP.

Study Year 2027

The incremental impact of each modeling update on the capacity need for the study year 2027 is documented in Figure 7-5. The starting point is the 2019 IRP Process capacity need with Colstrip Units 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-5: Impact of Key Input Revisions for 2027

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2027 - Sep 2028
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	1,867
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2027-2028	960	
	Updated balancing reserves for 2025 Case	918	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	982	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP Load Forecast for October 2027 – September 2028		1,334
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,273
	Updated Lund Hill generation to NREL data		1,291
	Add Golden Hills		1,161
	Add new RFP resource		1,018
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		887
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		881
	Fixed correlations for wind and solar data		907

Figure 7-6 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 907 MW of perfect capacity is needed in the year 2027 to meet the 5 percent LOLP.

Figure 7-6: Reliability Metrics at 5% LOLP for 2027

Metric	Base System – no added resources	System at 5% LOLP – add 907 MW
LOLP	68.84%	4.99%
EUE	5,059 MWh	430 MWh
LOLH	11.06 hours/year	0.83 hours/year
LOLE	12.58 days/year	0.12 days/year
LOLEV	2.49 events/year	0.14 events/year

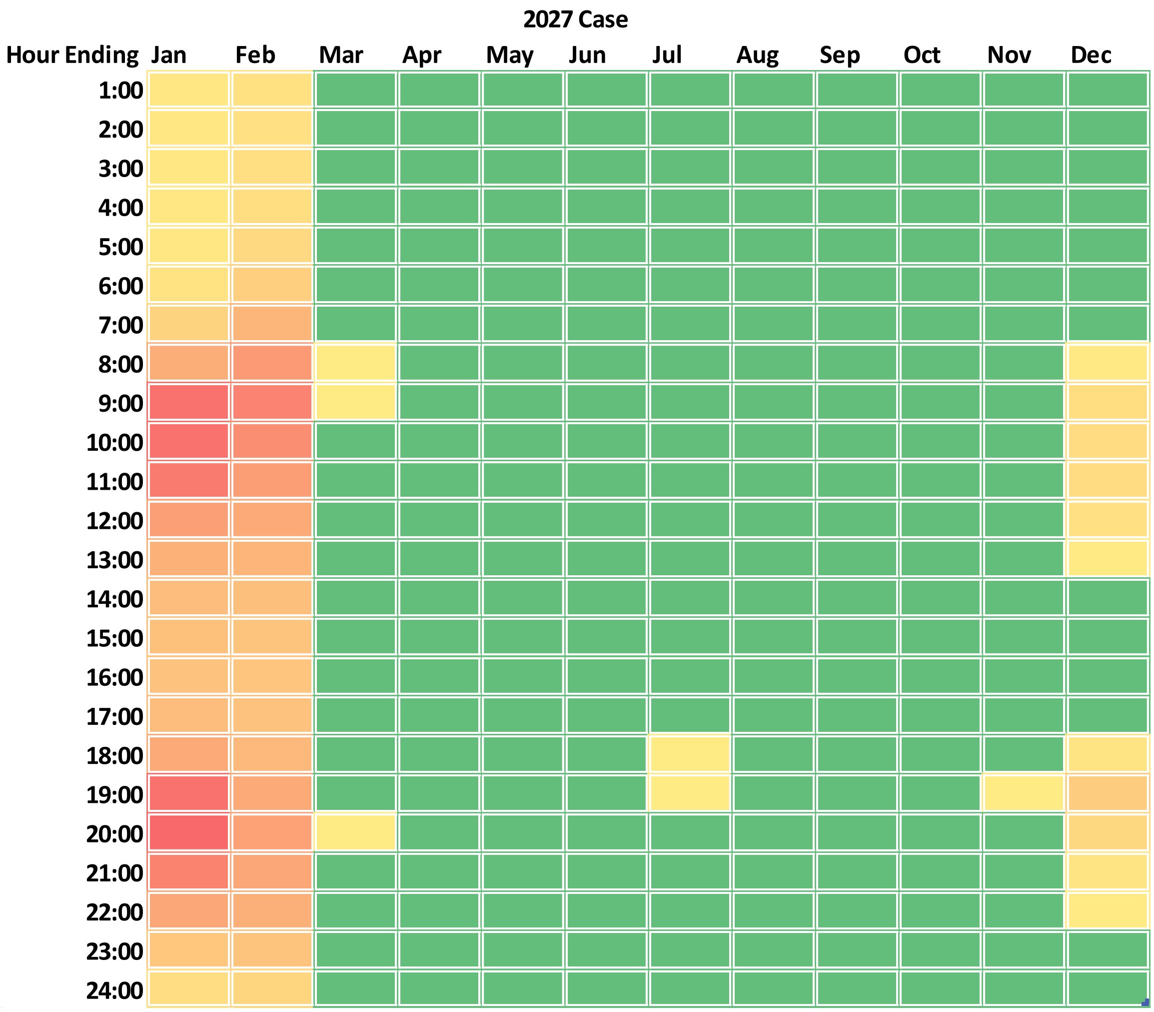
A loss of load event can be caused by many factors, which may include temperature, demand, hydro conditions, plant forced outages and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. Figure 7-7 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February. However, this is the first time that we are seeing events occur in the summer, even though they affect few hours (about 0.04 percent of total hours). Given this result, PSE is still strongly winter peaking; we do not see this changing but will continue to monitor the summer events.

Figure 7-7: Hours of Loss of Load across 7,040 Simulations for 2027

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	4,846	2,893
2	3,296	2,553
3	10	5
4	-	-
5	-	-
6	10	-
7	3	2
8	-	-
9	-	-
10	-	-
11	5	1
12	474	275

Figure 7-8 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-8: Loss of Load Hours for 2027



Study Year 2031

The incremental impact of each modeling update on the capacity need for the study year 2031 is documented in Figure 7-9. The starting point is the 2019 IRP Process capacity need with Colstrip 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-9: Impact of Key Input Revisions for 2031

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2031 - Sep 2032
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	2,217
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2031-2032	956	
	Updated balancing reserves for 2030 case	1,071	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	1,134	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP demand forecast for October 2027 – September 2028		1,635
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,581
	Updated Lund Hill generation to NREL data		1,596
	Add Golden Hills		1,469
	Add new RFP resource		1,326
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		1,344
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		1,361
	Fixed correlations for wind and solar data		1,381

Figure 7-10 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 1,361 MW of perfect capacity is needed in the year 2031 to meet the 5 percent LOLP.

Figure 7-10: Reliability Metrics at 5% LOLP for 2031

Metric	Base System – no added resources	System at 5% LOLP – add 1361 MW
LOLP	98.45%	5.00%
EUE	19,243 MWh	419 MWh
LOLH	51.90 hours/year	0.86 hours/year
LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

Figure 7-11 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February.

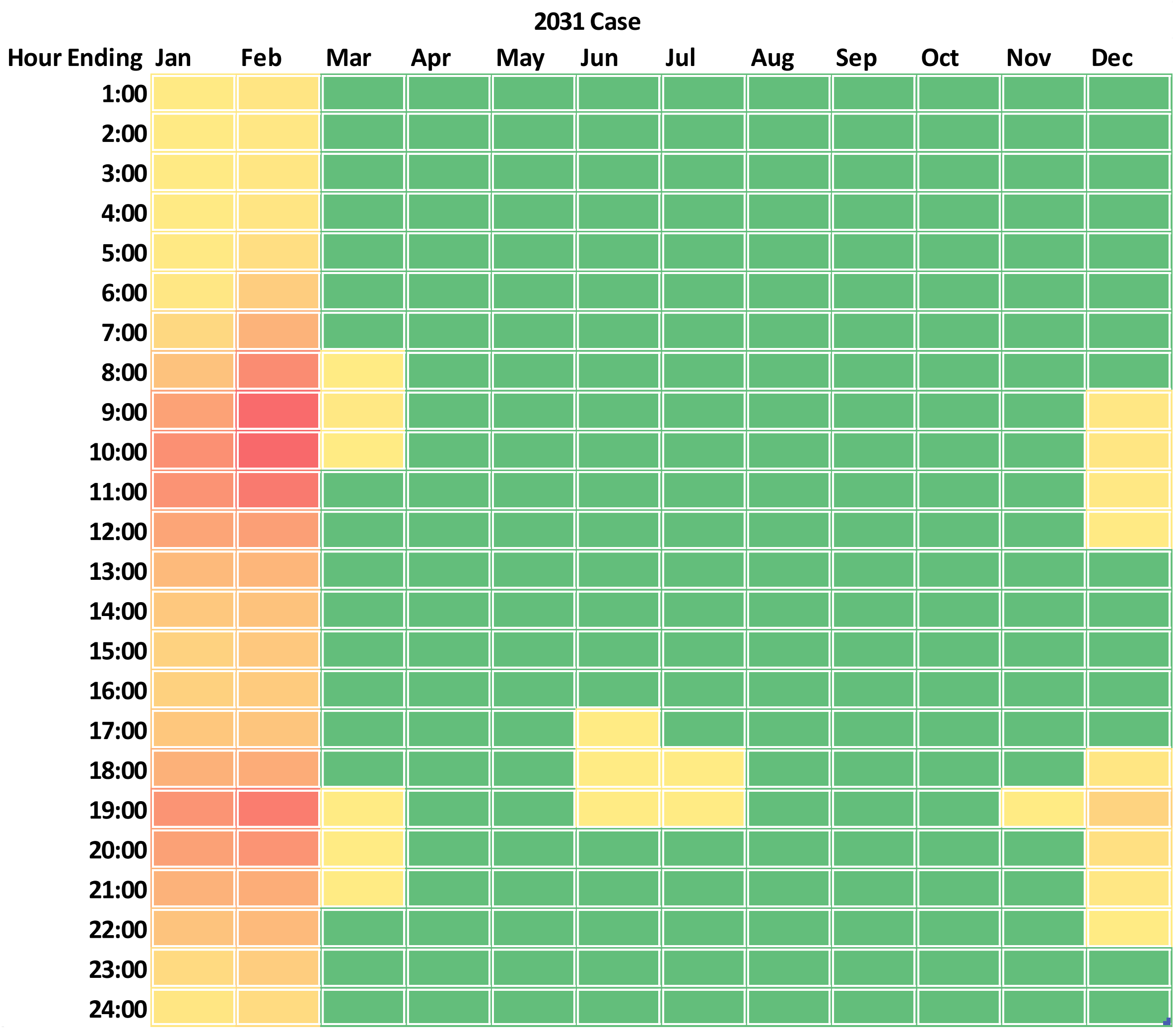
Figure 7-11: Hours of Loss of Load across 7,040 Simulations for 2031

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	3,860	2,387
2	4,267	3,365
3	40	14
4	-	-
5	-	-
6	12	5
7	4	2
8	4	-
9	-	-
10	-	-
11	9	1
12	325	160

7 Resource Adequacy Analysis

Figure 7-12 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-12: Loss of Load Hours for 2031



6. RESOURCE NEED

Planning Margin Calculation

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. Using the LOLP methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031. The planning margin is used as an input into the AURORA portfolio capacity expansion model. It is simply a calculation used as an input into the model to make sure that the expansion model targets 907 MW of new capacity in the year 2027 and 1,381 MW in the year 2031. The planning margin calculation for the 2021 IRP is summarized in Figure 7-13. The Total Resources Peak Capacity Contribution is the combined peak capacity contribution of all the existing resources in PSE's portfolio and is also referred to as the effective load carrying capability (ELCC). The peak capacity contribution of planned future resources is described later in this chapter.

Figure 7-13: 2021 IRP Planning Margin Calculation

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	907 MW	1,381 MW
Total Resources Peak Capacity Contribution	3,591 MW	3,599 MW
Short-term Market Purchases	1,471 MW	1,473 MW
Generation Capacity	5,969 MW	6,453 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.7%**	**24.2%**

The total peak capacity contribution of existing and new resources has been updated based on the 2021 IRP ELCC calculation.

Peak Capacity Credit of Resources

The effective load carrying capability (ELCC) of a resource represents the peak capacity credit assigned to that resource. It is calculated in RAM since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of perfect capacity that would yield the same level of reliability. For resources such as a wind, solar, or other energy-limited resources such as batteries and demand response programs, the ELCC is expressed as a percentage of the equivalent perfect capacity. Since the

ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. For example, LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency, expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries and demand response, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies.

HYDRO RESOURCES CAPACITY CREDITS. The estimated peak contribution of hydro resources was modeled in the RAM. We only modeled the ELCC of PSE owned hydro, Baker River Projects and Snoqualmie Falls. The peak capacity contribution of the Mid-C hydro is based on the Pacific Northwest Coordination Agreement (PNCA) final regulation and represents PSE's contractual capacity less losses, encroachment and Canadian Entitlement.

Figure 7-14: Peak Capacity Credit for Hydro Resources Based on 5% LOLP Relative to Perfect Capacity

Hydro Resources	ELCC Year 2027 (MW)	ELCC Year 2031 (MW)
Upper Baker Units 1 and 2	90	90
Lower Baker Units 3 and 4	82	79
Snoqualmie Falls	38	37

Figure 7-15: Peak Capacity Credit for Mid-C Hydro Resources
Based on Contractual Capacity Less Losses, Encroachment and Canadian Entitlement

Hydro Resources	Peak Capacity Credit Year 2027 (MW)	Peak Capacity Credit Year 2031 (MW)
Priest Rapids	5	5
Rock Island	121.2	121.2
Rocky Reach	313	313
Wanapum	6.1	6.1
Wells	115	115

THERMAL (NATURAL GAS) RESOURCES CAPACITY CREDITS. The peak capacity contribution of natural gas resources is different than other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need is at 23 degrees Fahrenheit, the capacity of natural gas plants is set to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. The forced outage of natural gas resources is accounted for in the variability of the 7,040 simulations. As mentioned in the "consistency with regional resource adequacy assessments" section above, PSE uses the "Frequency Duration" outage method in AURORA to simulate unplanned outages (forced outage) for thermal plants. The forced outage is already incorporated into the 907 MW capacity need.

Figure 7-16: Peak Capacity Credit for Natural Gas Resources

THERMAL RESOURCES	Peak Capacity Credit based on 23 degrees (MW)
Sumas	137
Encogen	182
Ferndale	266
Goldendale	315
Mint Farm	320
Frederickson CC	134
Whitehorn 2 & 3	168
Frederickson 1 & 2	168
Fredonia 1 & 2	234
Fredonia 3 & 4	126
Generic 1x0 F-Class Dual Fuel Combustion Turbine	237
Generic 1x1 F-Class Combined Cycle	367
Generic 12x0 18 MW Class RICE	219

WIND AND SOLAR CAPACITY CREDITS. In order to implement the ELCC approach for wind and solar in the RAM, the wind and solar projects were added into the RAM incrementally to determine the reduction in the plant's peaking capacity needed to achieve the 5 percent LOLP level. The wind project's peak capacity credit is the ratio of the change in perfect capacity with and without the incremental wind capacity. The order in which the existing and prospective wind projects were added in the model follows the timeline of when these wind projects were acquired or about to be acquired by PSE: 1) Hopkins Ridge Wind, 2) Wild Horse Wind, 3) Klondike Wind, 4) Lower Snake River Wind, 5) Skookumchuck Wind, 6) Lund Hill Solar, 7) Golden Hills Wind, 8) New RFP Resource, and finally 9) a generic wind or solar resource. Figure 7-17 below shows the ELCC of the wind and solar resources modeled in this IRP.

Figure 7-17: Peak Capacity Credit for Wind and Solar Resources Based on 5% LOLP Relative to Perfect Capacity

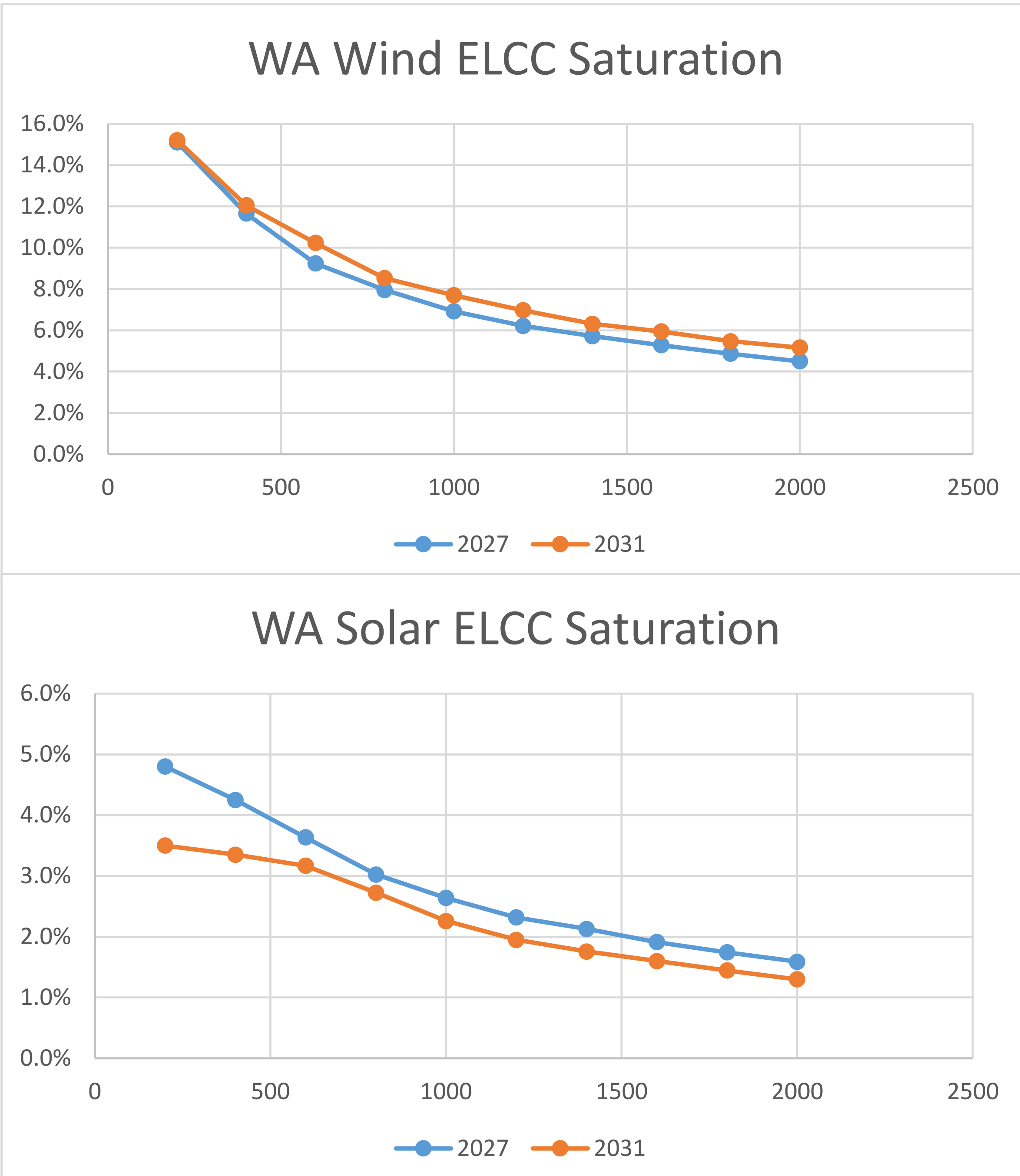
WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar[1]	100	4.0%	3.6%
Generic WA West Solar – Utility-scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

NOTES

1. This ELCC is for the first 100 MW of the resource, the saturation curve for up to 2,000 MW is shown below.

ELCC saturation curves: The peak capacity credit in Figure 7-17 above is for the first 100 MW of installed nameplate capacity for Washington wind and solar. Figure 7-18 below is the ELCC for the next 200 MW and then the next 200 MW after that and so on. The Figure shows a decreasing ELCC as more wind or solar is added to the same region.

Figure 7-18: Saturation Curves for Washington Wind and Solar



STORAGE CAPACITY CREDIT. The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19.

Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's peak capacity contributions with other entities. Some of the peak capacity contributions are higher and some lower depending on PSE's needs, demand shapes and availability of the supply-side resources. PSE's winter peak makes it different than the parts of the western interconnect that have a summer peak. Summer peaking events are focused in the late afternoon/evening when the day is the hottest and only last a few hours in the evening, which makes energy storage an ideal solution. However, a winter event can last several days at a time and temperatures can drop low during the night and stay low throughout the day. The low peak capacity contribution for energy storage is because these are short duration resources. As shown in Figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.

Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

HYBRID RESOURCES CAPACITY CREDIT. The capacity contribution of a solar plus battery storage resource is also estimated using EUE. The peak capacity credit of a solar plus battery storage resource is shown in Figure 7-20.

Figure 7-20: Peak Capacity Credit for Hybrid Resource Based on EUE at 5% LOLP

SOLAR + BATTERY RESOURCE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	15.4%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	23.0%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	57.7%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The peak capacity contribution of demand response is shown in Figure 7-21.

Figure 7-21: Peak Capacity Credit for Demand Response

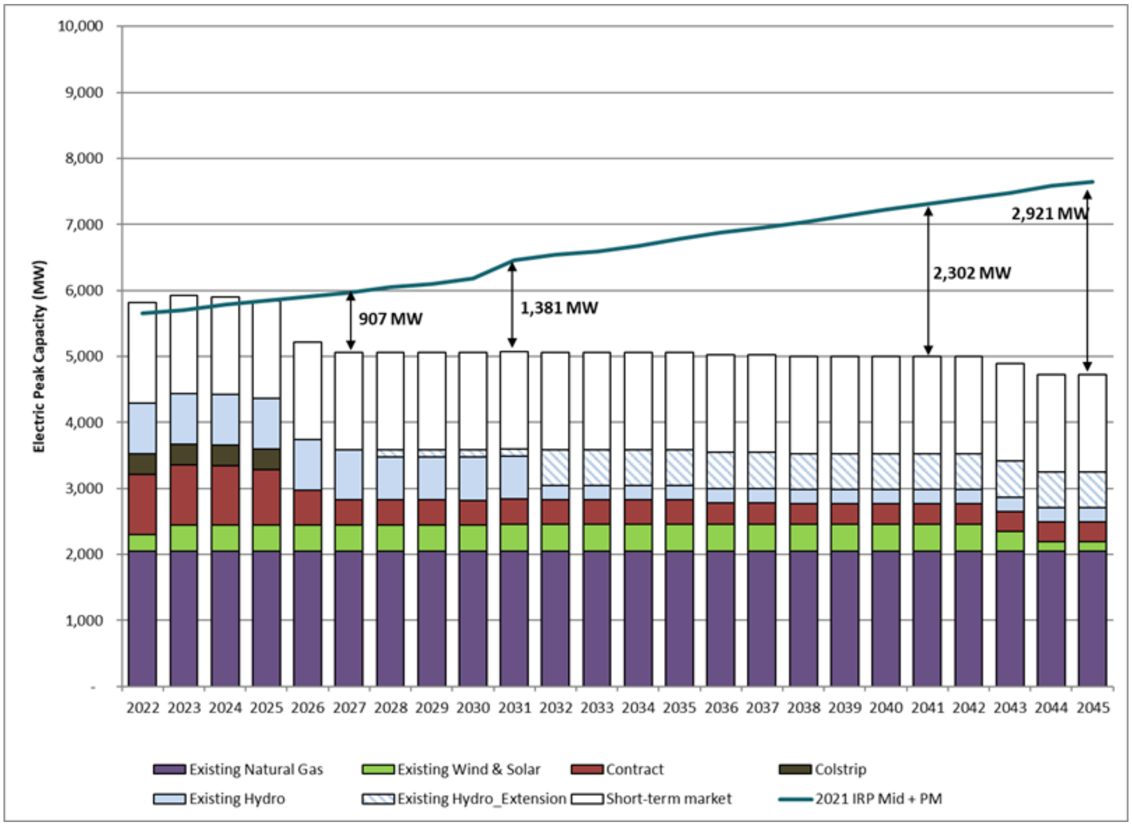
DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Peak Capacity Need

Figure 7-22 shows the peak capacity need for the mid demand forecast modeled in this IRP. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031 (represented by the teal line in Figure 7-22). This includes a 20.7 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent LOLP planning standard. The graph shows a noticeable drop in PSE's resource stack at the end of 2025. The drop is caused by the elimination of Colstrip 3 & 4 from PSE's energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE's 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025.

The peak capacity deficit assumes that 1,500 MW of market purchases is available to meet peak capacity need. Further analysis of market risk is described below.

Figure 7-22: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



7. ALTERNATIVE FUEL NEED FOR RESOURCE ADEQUACY

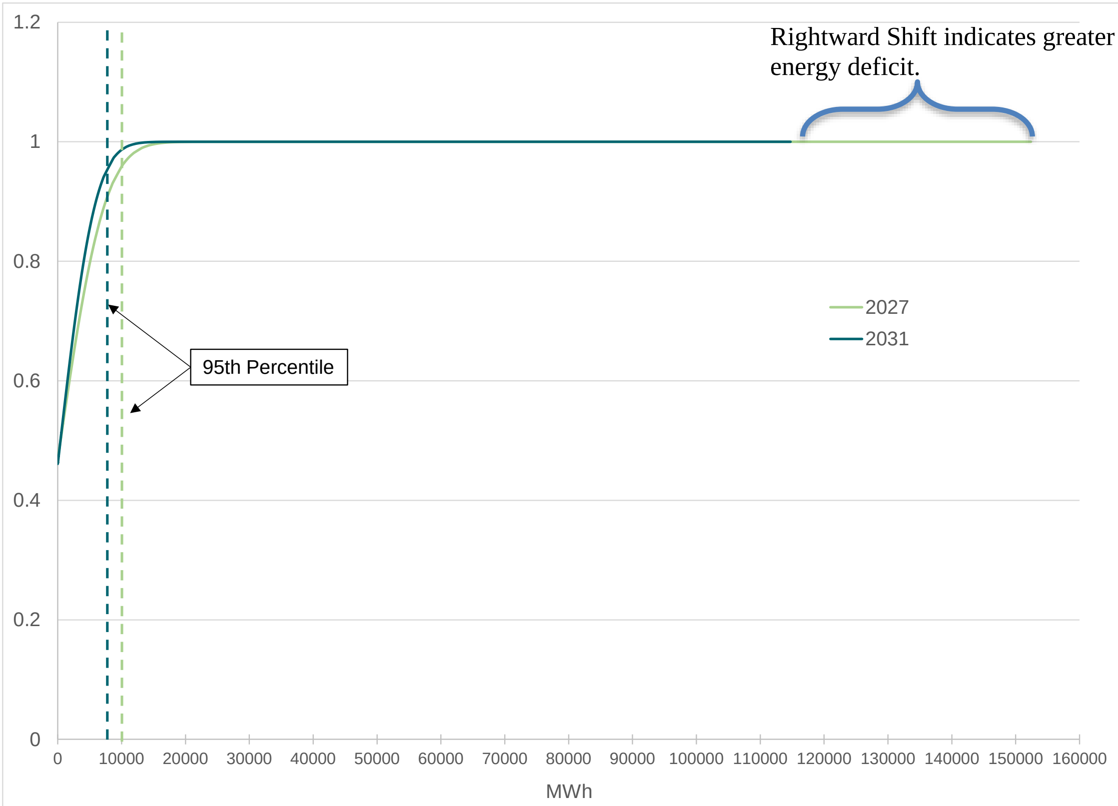
As part of the 2021 IRP, PSE tested CETA-compliant alternative fuels for peakers. When analyzing alternative fuels such as biodiesel, two key issues arise:

1. How many hour many run hours are needed for the year in order to maintain resource adequacy?
2. Is there enough fuel supply?

Incremental outages are examined, using RAM, for loss of load events and hours of outages. Because RAM is a stochastic model performing analysis over 7,040 draws, both the MWh outages and hours of outages are presented as a cumulative distribution.

Figure 7-32 shows the cumulative distribution of generation (MWh) resulting from the incremental outage events for model years 2027 and 2031. This sensitivity was run by removing the peakers form the portfolio and determining how much generation is needed to maintain resource adequacy. The higher the level of capacity that is unable to run due to the lack of peaker generation, the greater the amount of deficit. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the 95th percentile of generation that the peakers are needed to maintain resource adequacy.

Figure 7-32: Cumulative Distribution of Incremental Deficit for Loss of Load Events for All Simulations in MWh/yr



In 95 percent of simulations, to maintain resource adequacy, the peakers are needed to run for 10,000 MWh or less, which is around 15 hours of run time, and the maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[4] on biofuel production, the total annual production of biodiesel in Washington state is 114 MM gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel or about 0.7 percent of Washington State's annual production.

4 / *https://www.eia.gov/biofuels/biodiesel/production/*

8. MARKET RISK ASSESSMENT

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases under the WSPP contract schedule C,[5] where physical energy can be sourced in the day-ahead or the real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and ensuing procurement. For this IRP, PSE conducted a market risk assessment to evaluate the 1,500 MW assumption in addition to the evaluation completed with the WPCM.

The market risk assessment results in a proposal to increase firm resource adequacy qualifying capacity contracts while limiting the amount of real-time, day-ahead and term market purchases from 1,500 MW to 500 MW by the year 2027 to satisfy peak capacity needs. Support for such a reduction is based on changing market fundamentals in the Western Electricity Coordinating Council (WECC) that impact PSE's ability to access firm market purchases to meet demand. A reduction from 1,500 MW to 500 MW by 2027 provides a realistic and feasible path towards firm capacity for long-term peak capacity planning. The reduction in market purchases used in IRP planning is supported by the reduced capacity and liquidity in the region, coupled with increased volatility at the Mid-C market hub. The events of August 2020 underscore the need to change the IRP planning assumptions; in that event, PSE and other entities were not able to procure additional supply from the market.

Changing WECC Supply/Demand Fundamentals

Generating Capacity Changes

Power market supply/demand fundamentals have changed significantly in recent years. As customers, corporations and state legislatures across the Western Interconnection prefer or require power from clean energy sources, intermittent energy sources – namely wind and solar – have been built while traditional dispatchable capacity resources have been retired or mothballed. The growing capacity deficit in the region has been well documented in several recent studies.[6] Since 2016, nearly 15,000 MW of clean capacity and 500 MW of batteries have been added to

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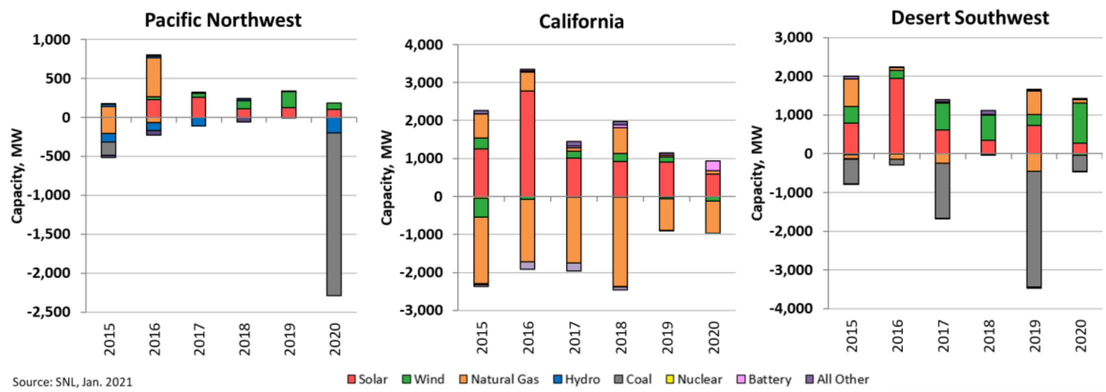
5 / https://www.wspp.org/pages/Agreement.aspx

6 / 2018 Pacific Northwest Loads and Resources Study (White book) (BPA, 2020); Resource Adequacy in the Pacific Northwest (E3, 2019); 2018 Long-Term Reliability Assessment (North American Reliability Corporation and Western Electricity Council, 2018); Pacific Northwest Power Supply Adequacy Assessment for 2023 (Northwest Power and Conservation Council, 2018); Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029 (Pacific Northwest Utilities Conference Committee, 2019); Long Term Assessment of the Load Resource Balance in the Pacific Northwest (Portland Gas and Electric and E3, 2019) the grid while 12,000 MW of coal and natural gas resources have been retired, as illustrated in Figure 7-23.

Figure 7-23: Capacity Additions and Retirements Since 2016

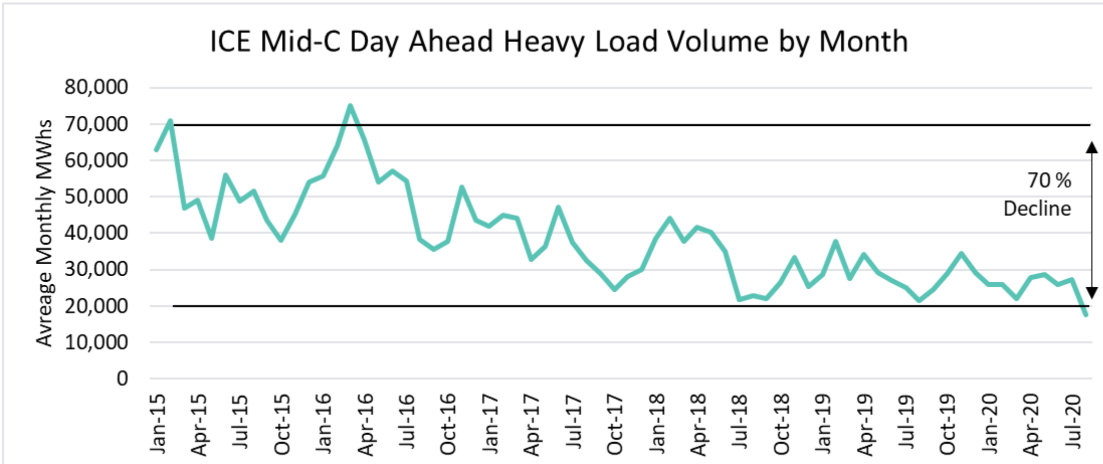


Included in Pacific Northwest thermal retirements are the retirements of Colstrip 1 and 2 in January 2020, which increased PSE's reliance on the short-term market by 300 MW. With less dispatchable generation capacity within the WECC, market supply/demand fundamentals have tightened.

Transaction Volumes and Volatility

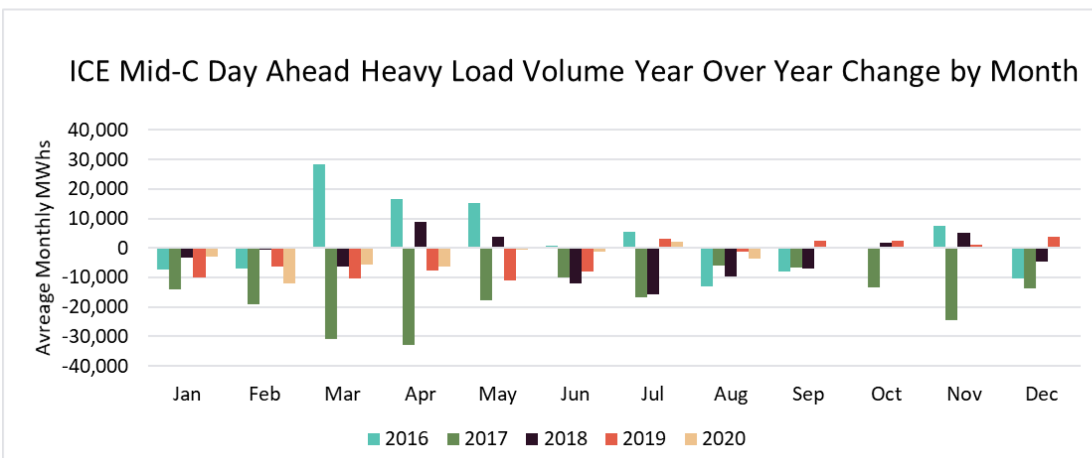
Reductions in traded volume in the day-ahead market also indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available which market participants can trade. This also is suggestive of energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 7-24 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 7-24: Mid-C Day-ahead Heavy Load Volume Timeline



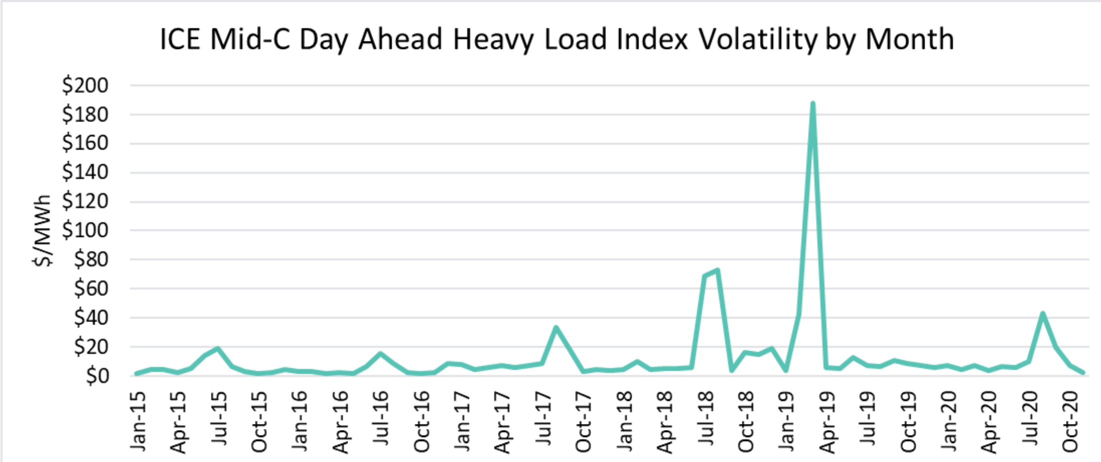
The decline has been consistent in all delivery periods. Figure 7-25 shows the average monthly change in trading volume from one year to the next. Negative bars show a reduction in trading volume while positive bars show an increase in trading volume.

Figure 7-25: Mid-C Day-ahead Heavy Load Volume Monthly Change



Additionally, price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018 when high regional temperatures coincided with forced outages at Colstrip; in March 2019 when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020 during a west-wide heat event. The volatility of day-ahead heavy load prices is presented in Figure 7-26.

Figure 7-26: Volatility of Heavy Load Mid-C Day-ahead Prices



Approach of Regional Investor Owned Utilities

Coinciding with the retirement of legacy baseload capacity and the decline of market liquidity, several regional investor owned utilities (IOUs) have reduced their assumptions of available market capacity in their IRPs. A lack of reliance or a reduced reliance on the market for capacity has precedent as shown in Figure 7-27. While it is difficult to get an exact comparison since IOUs have different resource planning assumptions, hedging and procurement practices, it is clear that PSE's market purchases are higher than other IOUs.

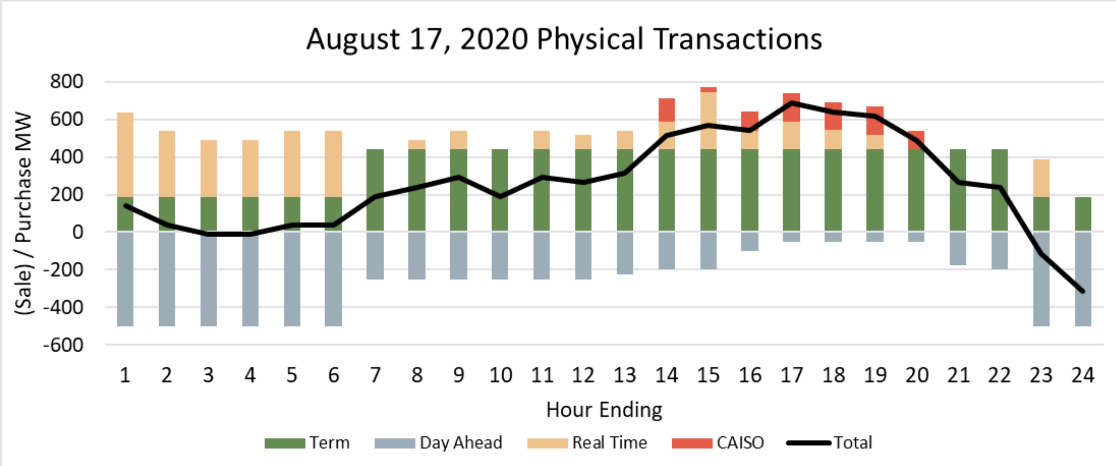
Figure 7-27: Regional IOU Market Reliance

Entity	Planned Summer Market Reliance Limit (MW)	Planned Winter Market Reliance Limit (MW)	Commentary
Avista	330	330	From the draft 2021 IRP. Market purchases are limited to 500 MW during 'unconstrained' hours, and 330 MW during 'constrained' hours
Idaho Power	N/A	N/A	The current IRP (2019) assumes market purchases of 500 MW in the summer and 425 MW in the winter. Specific market purchase limits are not defined in the IRP.
PacifiCorp	500 – Aggregate 150 – Mid-C Seasonal HLH	1000 – Aggregate 0 – Mid-C Seasonal HLH	Proposed Front Office Transaction Limits for the 2021 IRP cycle.
Portland General	50	0	Estimates from *Long Term Assessment of the Load Resource Balance in the Pacific Northwest* (Portland Gas and Electric and E3, 2019)
Puget Sound Energy	1,500	1,500	PSE counts historical energy offers at the Mid-C hub as available capacity to meet peak demand needs in the winter and summer.

Events of August 2020

Amid a west-wide heat wave lasting from August 14, 2020 to August 19, 2020, several balancing authority areas (BAAs) in the Western Interconnect declared various stages of energy emergency. This included the CAISO, which declared a stage 3 emergency and cut firm load on August 14 and 15. PSE's BAA declared a stage 1 emergency on August 17, 2020 as there was concern about the ability to procure capacity to meet load and contingency reserve obligations during hours ending 15 – 18 (3pm – 6pm). PSE's BAA ultimately did not progress further into emergency conditions and all load and contingency reserves were met. PSE ultimately relied on 400-505 MW of market purchases using WSPP-C contracts and 25 to 150 MW of exports from the CAISO, but could not procure additional capacity. This was significantly less than the 1,500 MW of market purchases that has been assumed to be available to meet demand in PSE's IRP. PSE's total market reliance on August 17, 2020 is shown in Figure 7-28. The different color bars show when the energy was procured for each hour on the day of August 17, 2020. Limited amount of imports from California were available.

Figure 7-28: Physical Transactions (MW) on August 17, 2020



Peak Capacity Need

ADJUSTED PEAK CAPACITY NEED. The reduction in market purchases to 500 MW increases the peak capacity deficit in 2027 from 907 MW to 1,853 MW. The planning margin calculation for the adjusted peak capacity need is summarized in Figure 7-29.

Figure 7-29: 2021 IRP Planning Margin Calculation with Declining Market Reliance

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	1,853 MW	2,263 MW
Total Resources Peak Capacity Contribution	3,586 MW	3,599 MW
Short-term Market Purchases	500 MW	500 MW
Generation Capacity	5,940 MW	6,362 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.0%**	**22.4%**

Figure 7-30 below shows the annual change in peak deficit for the declining market reliance and converting the short-term energy purchases to firm resource adequacy qualifying capacity contracts. The market availability at peak gradually declines over a 5-year period at 200 MW per year through to the year 2027. The gray area is the total available transmission to the Mid-C market. This position is usually left open to the short term market, but based on market availability, the open position will be reduced to 500 MW by 2027 with the remaining available transmission used for firm resource adequacy qualifying capacity purchases.

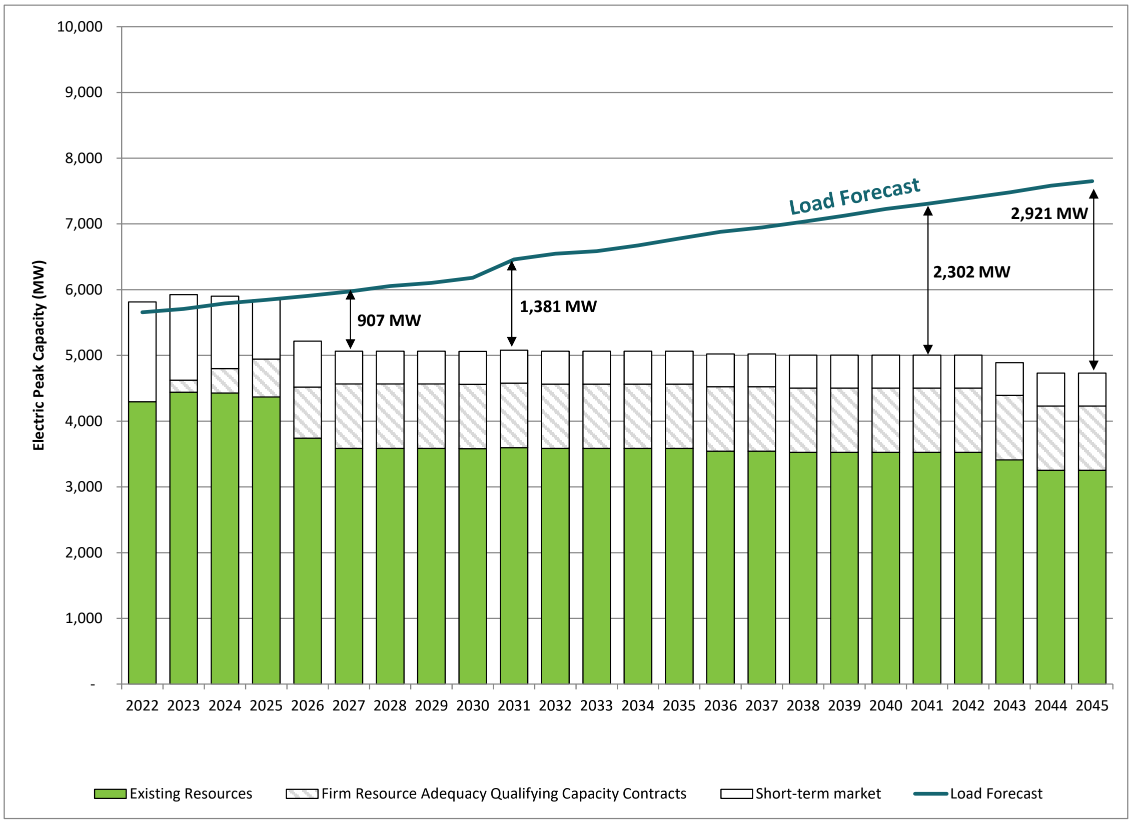
Figure 7-30: Short Term Market Purchases converted to Firm Resource Adequacy Qualifying Capacity Contracts

Year	Available Mid-C transmission (MW)	Short Term Market Purchases (MW)	Firm RA Qualifying Capacity Contracts (MW)
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

After 2031, the short term market stays at 500 MW and the firm resource adequacy qualifying capacity contracts at 979 MW.

Figure 7-31 shows the peak capacity need; the grey dashed bars highlight the reduced market purchases described above. Before any additional demand-side resources, peak capacity needed to meet the demand forecast plus planning margin – after reducing market purchases at peak – is 1,853 MW by the year 2027 and 2,263 MW by the year 2031.

Figure 7-31: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



9. TEMPERATURE SENSITIVITY

PSE committed to run a future temperature sensitivity as a way to begin to evaluate the impacts of climate change. This sensitivity was for the demand forecast only; PSE did not adjust hydro or wind for the adjusted temperature analysis. PSE relies on the Bonneville Power Administration (BPA) to do hydro modeling, and then PSE receives the data through the Pacific Northwest Coordination Agreement Hydro Regulation. This data has long been used by various organizations to estimate hydro variability. PSE will continue to align with BPA hydro modeling and will analyze any new data as it becomes available to better understand the impacts of climate change to the hydro system. There are three components to the temperature sensitivity analysis:

1. An updated energy demand forecast;
2. An alternative resource adequacy analysis; and
3. A portfolio sensitivity using the Aurora Long Term Capacity Expansion portfolio model.

The energy demand forecast is described in Chapter 6. The resource adequacy analysis adjustments made to account for the alternate temperatures is described below and the results of the portfolio sensitivity can be found in Chapter 8.

The base RAM analysis includes 88 historic temperature years. To create a wider range of possible future temperatures, and consistent with the stakeholder-selected energy demand forecast assumptions, PSE used three models that the NPCC has been using in its resource adequacy analyses. These models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA) are the product of a recent project by Bonneville Power Administration, U.S. Army Corps of Engineers and the Bureau of Reclamation that down-scaled global climate models to be more specific to the Northwest region. Each of these three models is on the Representative Concentration Pathway of 8.5, which some would argue is a “business as usual” pathway, while others would argue is a more extreme climate warming scenario.

The three models represent different amounts of warming over time. CanESM2_BCSD forecasts 0.9 degree of warming per decade, CCSM4_BCSD forecasts 0.9 degrees of warming per decade, and CNRM-CM5_MACA forecasts 0.5 degrees of warming per decade. While CanESM2_BCSD and CCSM4_BCSD have similar warming trends per decade, the temperatures from the two models are very different from year to year, and CanESM2_BCSD is a full degree warmer than CCSM4_BCSD, on average, over time.

PSE did not change the peak temperature assumptions for this analysis, because while average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Therefore, and as a result, the peak demand forecast did not change.

For each of the three models analyzed, weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RAM run, and weather from 2030 to 2039 was used for the 2031 to 2032 RAM run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model. This mirrors the methodology used in the NPCC resource adequacy analysis.

Using the LOLP methodology with the data from this temperature analysis, it was determined that 328 MW of capacity is needed by the year 2027 and 1,019 MW of capacity by the year 2031. The results of this sensitivity are compared with the base RAM results in Figure 7-32.

Figure 7-32: Peak Capacity Need

	Base	**Temperature Sensitivity**
2027 peak need	907 MW	328 MW
2031 peak need	1,381 MW	1,019 MW

The temperature analysis results showed more loss of load events in the summer caused by inadequate supply while in the base analysis, most loss of load events occurred in the winter season as shown in Figure 7-33. This shift in loss of load events from the winter to summer affects the peak capacity credit of resources. Resources with higher capacities in the summer, such as solar, now have higher peak capacity credit while those with strong winter generation become less effective with a lower peak capacity credit.

Figure 7-33: Frequency of Loss of Load Events by Month and Hour of Day for Model Years 2027 and 2031, Base Scenario and Temperature Sensitivity (red indicates more loss of load events, green indicates zero loss of load events)

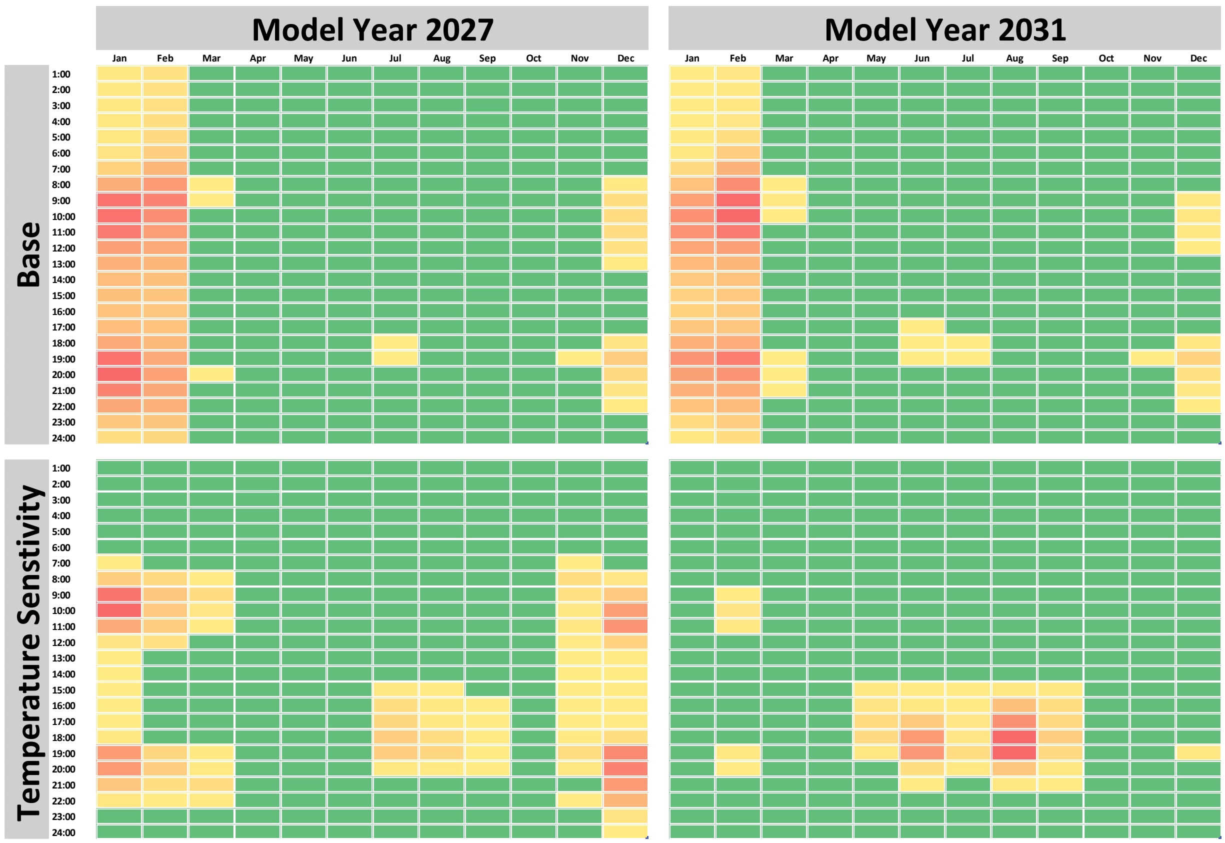


Figure 7-34 presents the effective load carrying capability of the generic resources for the temperature sensitivity as compared to the base scenario. The RAM results presented here were used to develop the inputs for the AURORA portfolio model.

Figure 7-34: Effective Load Carrying Capability for model years 2027 and 2031, Base Scenario and Temperature Sensitivity

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027		ELCC Year 2031	
		Base Scenario	Temp. Sensitivity	Base Scenario	Temp. Sensitivity
Existing Wind	823	9.6%	6.8%	11.2%	6.7%
Skookumchuck Wind	131	29.9%	17.6%	32.8%	9.2%
Lund Hill Solar	150	8.3%	30.3%	7.5%	54.3%
Golden Hills Wind	200	60.5%	49.3%	56.3%	39.3%
Generic MT East Wind1	350	41.4%	28.5%	45.8%	28.1%
Generic MT East Wind2	200	21.8%	13.1%	23.9%	17.7%
Generic MT Central Wind	200	30.1%	23.1%	31.3%	20.9%
Generic WY East Wind	400	40.0%	29.1%	41.1%	32.7%
Generic WY West Wind	400	27.6%	27.2%	29.4%	34.0%
Generic ID Wind	400	24.2%	25.6%	27.4%	28.0%
Generic Offshore Wind	100	48.4%	38.6%	46.6%	27.6%
Generic WA East Wind	100	17.8%	7.8%	15.4%	12.0%
Generic WY East Solar	400	6.3%	13.5%	5.4%	32.5%
Generic WY West Solar	400	6.0%	16.2%	5.8%	36.3%
Generic ID Solar	400	3.4%	16.0%	4.3%	47.3%
Generic WA East Solar	100	4.0%	21.6%	3.6%	45.6%
Generic WA West Solar – Utility-scale	100	1.2%	7.6%	1.8%	20.2%
Generic WA West Solar – DER Roof	100	1.6%	7.6%	2.4%	19.4%
Generic WA West Solar – DER Ground	100	1.2%	7.6%	1.8%	20.2%
BATTERY STORAGE					
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	34.2%	15.8%	36.0%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	66.6%	29.8%	68.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	61.6%	27.4%	63.8%
Flow, 6-hr, 73% RT efficiency	100	29.8%	79.2%	35.6%	84.8%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	89.2%	43.8%	97.8%
SOLAR + BATTERY RESOURCE					
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	22.0%	15.4%	56.6%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	26.0%	23.0%	17.8%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	73.0%	57.7%	64.0%

DEMAND RESPONSE					
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	60.4%	31.6%	61.4%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	69.8%	37.4%	80.8%

It is important to note that this is one model of possible weather changes and provides a preliminary view of the possible impact of warming temperatures. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made that inform the preferred portfolio in this IRP.

PSE will continue to model weather trends under different scenarios to try to better understand how not only extreme summer events can affect resource adequacy, but also to ensure we are planning for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past, there have been three separate regional energy events outside of PSE's control, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipate future changes to the resource adequacy analysis to include both a winter and summer resource adequacy analysis, and will work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.