

Resource Adequacy and ELCC Primer

Contents

- 1. Introduction and purpose
- 2. 2021 IRP Resource Adequacy analysis
 - Background
 - Resource Adequacy Modeling Approach
 - Peak Capacity Credit – Effective Load Carrying Capability (ELCC)
 - Loss of Load events and how that effects capacity credit
 - Storage Capacity Credit
 - Why use expected unserved energy (EUE) for energy limited resources?
 - Pumped Storage Hydro Analysis
- 3. Request for Proposal (RFP) modeling
- 4. Climate change analysis
- 5. Additional questions
- 6. Timeline for updates

1. Introduction and Purpose

During the development of PSE’s draft 2021 All-Source RFP, bidders and stakeholders raised many questions about PSE’s resource adequacy modeling process and evaluation of resource effective load carrying capability (ELCC) values. Questions ranged from general queries about resource adequacy methodologies to specific inquiries about the ELCC values of battery energy storage, pumped hydroelectric storage and hydroelectric resources. Another topic of interest for stakeholders was PSE’s decision to reduce its market reliance from 1,500 MW to 500 MW and whether this action constrained the ability of storage resources to be used to meet PSE’s identified capacity needs.

Given all the questions raised and the importance of ELCC in evaluating resources as part of the All-Source RFP, particularly in Phase 2 of the evaluation process, PSE agreed as part of the Utilities and Transportation Commission’s (Commission’s) review and approval process for its 2021 All-Source RFP to provide an ELCC primer to stakeholders and host a workshop to further review and explain its ELCC methodology, assumptions, and inputs and determine whether any updates or adjustments to PSE’s ELCC methodology or inputs for the RFP may be appropriate. To support this in-depth review, PSE

worked through its independent evaluator to hire a third-party consultant, E3. E3 will be presenting at the upcoming workshop on August 31, 2021, and their review will reflect on the reasonableness of PSE's ELCC methodology and inputs, with an eye towards addressing stakeholder questions and concerns that were raised during development of the draft RFP.

This primer is intended to serve as a resource for stakeholders who may have varying degrees of familiarity with PSE's ELCC methodology, as explained in the 2021 RFP, and how it is applied in the RFP process. Much of the information shared in this document can also be found in the materials supporting the 2021 IRP, with some additional explanation or examples added throughout in an attempt to improve clarity. The goal of this document is to help stakeholders better understand PSE's approach to ELCC and give stakeholders the tools to prepare for a robust discussion at the upcoming workshop.

2. 2021 IRP Resource Adequacy Analysis

Background

The energy supply industry is in a state of transition as major decarbonization policies are implemented in many 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, the Northwest Power Pool is designing and implementing a regional resource adequacy program. Documentation of the detailed design of the resource adequacy program was published in July 2021 and participation in the non-binding phase of the program is expected to commence in Q4 of 2021¹. As the detailed design documentation is processed and the non-binding program is established, PSE will further develop the evaluation of various resource adequacy elements in future IRP cycles to align with regional trends.

In addition to potential changes to the region brought about as a result of the Northwest Power Pool Resource Adequacy Program, PSE has also be re-examining its reliance on wholesale market purchases. 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 average wholesale electricity prices remain low, the Pacific Northwest (PNW) region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

¹ https://www.nwpp.org/private-media/documents/2021-08-10_NWPP_RA_2B_Design_v4_final.pdf

PSE has completed a market risk assessment which evaluates the availability of short-term market purchases for peak capacity. The results of the market risk assessment suggest that PSE should reduce its market reliance from 1500 MW to 500 MW by 2027. Additional details of the market risk assessment may be found in Chapter 3 of the 2021 IRP². PSE will 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 in future IRP cycles. PSE will host a workshop on the market reliance assessment at the end of September, 2021.

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, variations in 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, PSE uses a 5 percent loss of load probability (LOLP) reliability metric 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. In other words, 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) and other utilities in the region, see Figure 1. LOLP is just one of several resource adequacy metrics, below is a list of different metrics commonly used in resource adequacy analysis:

1. Loss of Load Probability (LOLP) as a percent per year (%).
2. Loss of Load Hours (LOLH) in hours per year (hrs/yr). The LOLH is the total number of hours in a year wherein load plus reserves exceeds generation. This helps to track the duration of the loss of load event.
3. Loss of Load Expectation (LOLE) in days per year (days/yr). The LOLE is the total number of days in a year where load plus reserves exceeds generations. This metric is used by CAISO and other utilities. The industry standard target is 1-in-10 or 0.1 day/yr.
4. Expected Unserved Energy (EUE) in energy per year (MWh/year). The EUE is the amount of energy lost during an event.

² PSE 2021 Integrated Resource Plan, Chapter 3,
https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/03.%20IRP21_Ch3_032921.pdf

The following table is a summary of the resource adequacy metrics used by utilities in the Pacific Northwest for resource planning. PSE tracks all the metrics as part of the resource adequacy model for comparison across different planning analyses.

Figure 1 – Utilities RA metric comparison

	Reliability Criteria	Capacity Contribution Methodology
Puget Sound Energy	LOLP (5%/year)	ELCC EUE adjusted for energy limited resources
Portland General Electric	LOLE (0.1 days/year)	Marginal ELCC
PacifiCorp	LOLH (2.4 hours/year)	LOLP based Capacity Factor
NorthWestern Energy	LOLE (0.1 days/year)	ELCC
Avista	LOLP (5%/year)	ELCC
Northwest Power and Conservation Council	LOLP (5%/year)	ASCC

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. Even neighboring utilities can have higher or lower ELCC values, depending upon their needs, demand shapes and availability of supply-side resources.

Resource Adequacy Modeling Approach

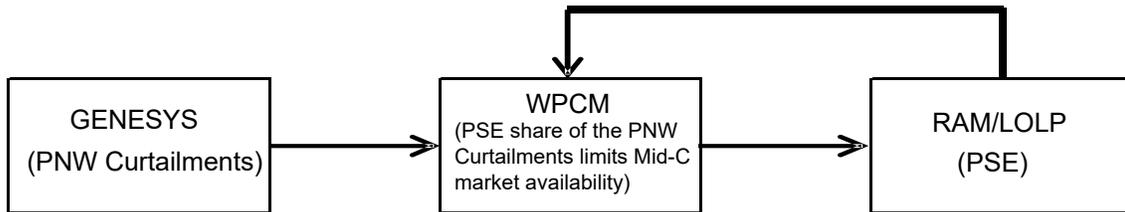
PSE’s Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE’s power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the classic GENESYS model³ 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 2 illustrates how the inputs and outputs of these models are linked. The outputs of the GENESYS Model provide inputs for both the WPCM model and the RAM/LOLP model. The RAM/LOLP model and

³ The GENESYS model has recently be updated to the “Redeveloped GENESYS” model by the NPCC and BPA for the 2021 Power Plan. The draft power plan will be out September 2021, with the final power plan early 2022. Given that the redeveloped GENEYS model is still under development and review and the results from the redeveloped GENESYS model are a departure from the classic analysis, PSE is validating and verifying use of the redeveloped GENESYS for future IRP analysis.

WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 2: Market Reliability Analysis Modeling Tools



PSE's resource adequacy model follows a 4-step process to determine the peak capacity need:

1. The GENESYS model is run for regional load curtailments
2. The load curtailments are then run through the WPCM to determine PSE's share of the curtailment.
3. The available Mid-C market is then adjusted by the size of the curtailment in the WPCM by hour
4. The RAM is then run for every hour for loss of load events and to find the capacity needed to achieve a 5% LOLP.

Resource Adequacy Model Inputs

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.
7. The analysis year was adjusted from 2022 in the 2019 IRP progress report to 2027 and 2031 in the 2021 IRP

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 modeling timeframe follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact throughout the analysis. This is consistent with the NPCC’s GENESYS model. If the calendar year was modeled instead, 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 (e.g. Skookumchuck and Lund Hill). The detailed updates to the GENESYS models are discussed in the 2021 IRP, Chapter 7⁴.

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.

UNCERTAINTY MODELED IN RAM. 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 AURORA⁵ 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 employs all or nothing outages for most outages, but partial outages are permitted at the beginning or end of an 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 ignores 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 (1929-2016). The 88 temperature years matches the inputs into the GENESYS model for consistency between the two models. The demand draws are created with

⁴ PSE 2021 Integrated Resource Plan, Chapter 7,

https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/07.IRP21_Ch7_032921.pdf

⁵ A full explanation of the AURORA model and how it’s used in the IRP is included in the 2021 IRP, Appendix G, https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/Appendix/18.%20IRP21_AppG_033021.pdf.

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 load forecasting 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 80-year hydro is estimated generation based on historical stream flow (1929 – 2008) with current operating conditions at each hydro facility. The Northwest Power and Conservation Council uses the stream flow data provided by BPA through their Regulation model which accounts for the current operating conditions of the hydro facility to estimate generation levels for each historic stream flow year. The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model where the hydro and temperature years are not correlated together. Each hydro draw is matched with each load draw: 80 hydro generation draws * 88 load draws = 7,040 simulations.
- 4. WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind or solar 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 and reflected in the analysis. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. PSE obtained wind speed data from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.⁶ Data was collected from numerous sites within a prescribed radius around a region of interest. The 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 a given site, as determined by the average of the entire data set, were selected for use in the RAM. Those profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database⁷ 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.

⁶ <https://www.nrel.gov/grid/wind-toolkit.html>

⁷ <https://nsrdb.nrel.gov/>

5. 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 capacity 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 WPCM. 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 peak capacity need determined in the RAM incorporate PSE's wholesale market reliance risk.

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 coordinating entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events. This is for planning purposes only.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large⁸ buyers purchase 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

⁸ The utilities include PSE, Portland General Electric (PGE), PacifiCorp, Avista, and Idaho Power.

automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be 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.

Below is the calculation for the available Mid-C market:

$$\text{Available Mid-C market} = \text{Available transmission} - \text{Wild Horse} - (\text{Mid-C hydro} + \text{spinning reserves}) - \text{curtailment from WPCM}$$

The available transmission is 2,031 MW and a full breakdown of the contracts is included in the 2021 IRP, Appendix D⁹. Wild Horse, Mid-C hydro, reserves, and curtailment are all calculated on an hourly basis, so this number is changing each hour.

Results of the Resource Adequacy Model

Figure 3 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 and 1,361 MW in 2031.

Figure 3: 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

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

⁹ PSE 2021 Integrated Resource Plan, Appendix D, https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/Appendix/15.%20IRP21_AppD_031821B.pdf

LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

Peak Capacity Credit of Resources - ELCC

Resources with different operational characteristics will fill a utility’s resource need differently. These differences need to be reflected in the portfolio modeling in some way, to try and help ensure portfolio models will actually achieve the desired resource adequacy metrics in a way that reasonably reflects the relative value different resources have to meeting those needs. Such differences are often reflected by estimating an effective load carrying capability (ELCC) for resources with different operating characteristics. The ELCC approach is a way of calibrating peak capacity values across resource types for the next step of the analysis. The 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 capacity¹⁰ 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.

Why is ELCC important? A peaking plant with firm, year-round fuel supply is a physical call option that can be used any and every hour of the year whenever needed to meet loads. These plants are very flexible and fully dispatchable, but they are machines, so may not operate when needed (called a forced outage). Energy storage systems including batteries and pumped hydro storage are also very flexible and dispatchable *if* they are charged. If adequate surplus electricity is not available to charge them, they are not useful, so will not be as effective at meeting loads during all hours like a peaker. Steam plants, such as nuclear, coal, or gas boilers meet resource needs, but typically have long-ramp up periods, so unlike energy storage or peakers, cannot be dispatched to meet unexpected changes in hourly load-resource balances. Finally, intermittent resources like wind will meet resource needs when the wind is blowing, if the wind is blowing when needed. Because of its intermittent nature, wind is typically not as reliable as energy storage or peakers.

ELCCs for each resource type are typically estimated on a marginal, standalone basis, which is how PSE performed the analysis for the 2021 IRP in the following steps:

1. Assess Starting Baseline for Test Period: 2027 and 2031

¹⁰ Perfect capacity is a modeling tool used to represent a resource which is available at full capacity, every hour of the year.

2. Balance Portfolio to 5% LOLP with perfect capacity: 907 MW needed in 2027 and 1,361 MW in 2031 (results above).
3. Add a new resource to the resource adequacy model and then recalculate the need for perfect capacity
4. Take the change in need from the baseline portfolio and the new portfolio with the resource added and divide by the size of the new resource.

Example Calculation.

$$ELCC = -(Need_2 - Need_1)/Change$$

1. Base case need = 500 MW
2. Add 100 MW nameplate renewable, New need = 475 MW
 - a. The perfect capacity is reduced to 475 to maintain the 5% LOLP
3. $ELCC = -(475 \text{ MW} - 500 \text{ MW})/100 \text{ MW} = 25\%$

The full set of ELCC's are represented in Figure 4. The ELCC of new generic resources were assessed as an incremental add to the existing portfolio which includes Existing Wind (Hopkins Ridge, Wild Horse, Lower Snake River 1, and Klondike III), Skookumchuck Wind, Lund Hill Solar, Golden Hills Wind, and Clearwater Wind.

Figure 4: Effective Load Carrying Capability for model years 2027 and 2031

	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
WIND AND SOLAR RESOURCES			
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%
Clearwater Wind (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	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	100	4.0%	3.6%

	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
WIND AND SOLAR RESOURCES			
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%
BATTERY STORAGE			
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%
RENEWABLE + STORAGE HYBRID RESOURCE			
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 Wind2, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	57.7%
DEMAND RESPONSE			
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%

It is critical to recognize that marginal ELCCs are dependent on the loads and existing resources being used in the analysis. As “marginal” ELCCs, PSE is calculating how much each resource type contributes the very last bit of resource need. The larger, longer duration outages have all been covered by perfect resources. That is, underlying all this analysis, we start with the assumption that 907 MW of perfect capacity resources were actually in the portfolio that do not actually exist. As peakers are the closest supply-side resource to perfect capacity, we are basically assuming if we had an additional 907 MW of peakers available in all hours, how many battery resources would we need to fill that last 50 MW of need? Of course, that implies PSE will have additional dispatchable resources that create surpluses in many hours available to charge the batteries that we don’t really have. If we calculated the ELCC of batteries or other resources to fill the entire 907 MW, the results would be vastly different.

This highlights an important limitation to using ELCCs of any kind: they are “state dependent”. For example, PSE calculates saturation curves that show adding more and more wind in the same location reduces the ELCC of the resource. The same condition holds for various combinations of resources.

Applying marginal¹¹ ELCCs is good for small scale decisions, like the next plant. With large resource gaps, though, if significant amounts of resources are added that do not mimic “perfect” resources, the portfolio may fall short of the targeted 5% LOLP target.

If ELCCs are state dependent, why not just do all this analysis within the portfolio model? Resource adequacy modeling is very complex as is portfolio modeling. At this time, it is not possible to combine robust modeling of both aspects simultaneously, so the analyses must be done sequentially. It is generally desirable to run a candidate resource portfolio through the RAM after applying the planning reserve margin and marginal ELCCs in the portfolio modeling process, to make sure the portfolio is still achieving the targeted LOLP. PSE has performed this iteration in prior IRPs and found resource plans achieved the targeted 5% LOLP. In the 2021 IRP, PSE did not run all 42 portfolio sensitivities through the RAM. The number of sensitivities performed in response to stakeholder requests made such an endeavor infeasible. However, PSE does plan to model resources selected for Phase 2 of the 2021 All Source RFP through the RAM model to measure their impact on portfolio resource adequacy.

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. LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occur 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 inclusive 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.

LOSS OF LOAD EVENTS. 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 5 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number of hours of lost load summed by month and hour of day. The majority of the lost load hours occur in the winter months. From this chart, we can see long durations, 24 hours or more, with a loss of load event.

¹¹ “Marginal” typically means infinitesimally small changes.

Figure 5: Loss of Load Hours for 2027 and 2031



PSE’s winter peak has notably different characteristics than a summer peak in other parts of the Western Interconnect. Summer peaking events occur in the late afternoon/evening when the day is the hottest and only last a few hours in the evening. Energy storage is a good solution for summer peaking events. In contrast, winter events can last several days at a time and temperatures can drop low during the night and stay low throughout the day. Since energy storage is a short duration resource that has a low peak capacity credit in PSE’s portfolio, it is not a good fit for winter peaks. With lower peak capacity credit, more energy storage resources are needed to replace the new peaking capacity added in the portfolio.

STORAGE CAPACITY CREDIT. The estimated peak contribution of lithium-ion and flow batteries, as well as pumped hydro storage were modeled in RAM. Both 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.

Why use EUE for energy limited resources? 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. This is important when determining the size of energy storage needed to maintain reliability. Because of this, the ELCC of batteries is estimated using the expected unserved energy (EUE) metric, in addition to LOLP. 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 an EUE at 5 percent LOLP, divided by the peak capacity of the storage resource added, determines the ELCC, or peak capacity credit of the storage resource.

Example Calculation.

1. Start with the base case need

$$\text{Base Need} = 907 \text{ MW, LOLP} = 4.99\%, \underline{EUE = 429.93 \text{ MWh}}$$

2. Add new resource to model. For this example, we are using a 100 MW nameplate 6 hr flow battery

3. Add perfect capacity to model until achieve equivalent EUE from Base Need.

$$\text{New Need} = 876.8 \text{ MW, LOLP} = 3.97\%, \underline{EUE = 429.6 \text{ MWh}}$$

4. Calculate ELCC by taking the new need minus the base need divided by the nameplate capacity.

$$\text{ELCC} = -(876.8 \text{ MW} - 906.6 \text{ MW})/100 \text{ MW} = 29.8\%$$

From this example, in order to achieve the same EUE as the base model, the LOLP is lower than 5%.

The estimated peak contribution of storage resources in PSE's RAM is shown in Figure 6.

Figure 6: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit	Peak Capacity Credit
		Year 2027	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%

As mentioned above, ELCCs are unique to each utility and dependent on load shapes and supply availability. PSE's winter peak makes its situation different than other 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. As shown in Figures 5 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources generally have a short discharge period (from 2 to at most 8 hours), they have little to contribute during extended events.

Pumped Storage Hydro Analysis. PSE tested several operational parameters for the pumped storage hydro resource. The assumption for the generic pumped storage hydro in the 2021 IRP was for a minimum operating range of 11.5% of nameplate capacity. Given the newer technology, the pumped storage hydro can operate at full 100% range (i.e. 0% minimum), so PSE tested the increased operating range to see if that would change the ELCC. Figure 7 below shows the ELCC for each scenario which shows a slight increase in the ELCC of pumped storage hydro with a 100% range of operation.

Figure 7: Pumped Storage Hydro ELCC comparison

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Pumped Storage Hydro, 11.5% minimum	100	37.2%	43.8%
Pumped Storage Hydro, 0% minimum	100	39.0%	45.8%

3. RFP Modeling

In the 2021 All Source RFP, PSE will use the ELCC values consistent with the 2021 IRP methodology for the quantitative evaluation in the Phase 1 and Phase 2 of the RFP evaluation.

Phase 1 Quantitative Analysis. The Phase 1 quantitative analysis will approximate the ELCC value of each proposed RFP resource using the ELCC value of a comparable generic resource from PSE’s 2021 IRP analysis. Based on their technology and location, resources in the RFP will be classified into subgroups that align with the 2021 IRP generic resource categories listed in Figure 5 and Figure 6. For example, Washington wind will be classified in a WA Wind subgroup with the WA wind generic ELCC, and another wind resource located in eastern Montana would be classified in a separate eastern MT Wind subgroup. Other RFP resource-specific characteristics, such as point of delivery, firmness of delivery, seasonality and generation profile, will be checked for comparability within the subgroups.

Variable energy resources (“VERs”) such as wind and solar delivered to the Mid-C transmission that PSE is making available for the RFP will not receive a capacity credit. This is because PSE’s market reliance

need is specifically tied to reliability concerns with the firmness of supply at the Mid-C market hub. And since standalone VERs are non-firm resources that cannot guarantee firm supply during peaking events, no capacity credit will be given to those resources. However, VERs with an ability to shape supply will receive a capacity credit.

A few examples may help illustrate why unshaped VERs delivering to Mid-C will not receive a capacity credit. In 2019, February 5th to 7th, an unexpected cold weather event occurred in the region. During this event wind generation over those three days averaged just 5 MW from PSE's approximately 800 MW of wind capacity. Another example of wind generation failing to deliver reliably was during a hot weather event that occurred August 15th to 17th in 2020. In this instance, out of PSE's entire wind portfolio, only an average of 61 MW could be delivered over those three days.

Pairing non-firm VER resources with firm transmission to address market reliance is inconsistent with the objective to reduce uncertainty of energy delivered on Mid-C BPA transmission during peaking events. Resources delivered to COB/Malin or COB/John Day in winter months for use of the California Oregon Interchange (COI) transmission will also not receive a capacity credit. This is because PSE is in a seasonal exchange with PG&E. The exchange volumes will utilize the COI transmission during winter months for up to 300 MW for a total of 413,000 MWh, and PSE will not guarantee acceptance of delivery during those months. PSE may have availability, however, on the COI during winter months on a day-ahead basis.

The generation profiles of resources (8760 schedule) will be graphed, analyzed and compared to verify general consistency with the associated generic resource assumption. If PSE identifies a proposal that significantly differs from the associated generic assumption, and the bidder provides independently verified third - party support for their generation output profile, PSE would take that into consideration in its analysis. If a bidder cannot provide this support, the generic ELCC assumption will be used. The All - Source RFP requires a minimum of one year of wind resource or solar irradiance data.

Adjustment will be also made for firmness of delivery or seasonality of offer. For example, if a resource can only secure partial or seasonal firm transmission of the full offered nameplate, the ELCC will be adjusted proportionally.

At the end of Phase 1, PSE intends to select a candidate pool of resources for portfolio optimization analysis that represent the best - performing proposals from different resource types and technologies to test the performance of combinations of resources toward achieving a lowest reasonable cost portfolio. This means that the ELCC values of one resource type compared to another is less important in Phase 1

because PSE will select a representative sampling of resources for further consideration, subject to meeting the minimum criteria defined in the All - Source RFP.

Phase 2 Quantitative Analysis. The Phase 2 quantitative analysis will be based on resource - specific ELCC values calculated for each Phase 2 resource. An individual project's ELCC will vary based on further due diligence and analysis of a variety of factors, including:

- Exact location of the resource,
- Verified generation shape (8760),
- Ability to dispatch,
- Duration of output,
- Availability of firm delivery to PSE's load center,
- Demonstrated firm fuel supply for biomass,
- Demonstrated ability to charge during a loss of load event for storage,
- Other resource-specific operational characteristics

At the end of Phase 2, PSE will also run a portfolio ELCC for the shortlisted resources to assess the correlations of the resource mix and whether the shortlisted resources sufficiently meet the capacity need.

4. Climate Change Analysis

In the 2021 IRP, PSE evaluated temperature variations that increased the summer loss of load events. This temperature sensitivity is one model of possible weather changes and provides a preliminary view of a possible impact of warming temperatures as a result of climate change. The lessons learned from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made from it to inform the preferred portfolio. Since this was a preliminary view, information was missing in this analysis, including impacts to the conservation potential assessment, hydro stream flow data, and extreme weather conditions. In addition, the resource adequacy model is set up to take 88 load draws, but the climate change data that PSE used from the Northwest Power and Conservation Council for this temperature sensitivity only contained 10 years of forward looking data. 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. The forward looking 10 years are a forecast of weather trends, but repeats weather patterns. This coupled with repeating years for the load draws results in a very limited view of possible extreme weather conditions. The purpose of the resource adequacy model is to look at possible "what if" scenarios - and that includes extreme weather events. By having a data set with a limited view and

repeating patterns, we are unsure if the results of the resource adequacy model are reasonable. Details of the analysis are provided in the 2021 IRP, Chapter 6 for the load forecast, Chapter 7 for the resource adequacy analysis, and portfolio results are presented in Chapter 8.

PSE will continue to model weather trends under different scenarios to better understand how summer extreme events can affect resource adequacy, but also to ensure that PSE continues to plan 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 beyond what was conducted in the temperature sensitivity to drive future resource planning changes.

PSE is committed to continuing this work for the 2023 IRP Progress Report. The current schedule anticipates an updated load forecast and resource adequacy analysis that will be finished in mid-2022 to inform Phase 2 of the RFP process. The resulting CPA and portfolio analysis will be included in the 2023 IRP Progress Report. Future changes to the resource adequacy analysis will include both winter and summer resource adequacy analyses, and PSE will also work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

5. Additional Questions

Stand-alone Storage

1. Are PSE's Resource Adequacy modeling assumptions and resulting Effective Load Carrying Contribution (ELCC) Values for Stand-Alone Energy Storage reasonable?
2. Are PSE's constraints on the charging and discharging limitations of a stand-alone energy storage resource reasonable?
3. Do PSE's assumptions unreasonably limit the capability of stand-alone energy storage to charge, limiting their ability to provide capacity in high loss-of-load winter periods?

Pumped Storage Hydro

1. It is unreasonable for PSE to limit pumped storage resources' operating range (or "state of charge") to 70% of the resource's storage capacity
2. Does this deflate PSH ELCC values?

Hybrid Resources

1. Does PSE unreasonably limit hybrid resources by only allowing them to charge from renewables over the entire lifecycle of the resource, undervaluing these resources' capacity and ancillary services contributions?

Market Limitation

1. Does the reduction in availability of market purchases in PSE's IRP artificially constrain the ability of storage resources (including battery and pumped hydro storage) to meet PSE's capacity needs?
2. Does the IRP impose a 1000 MW market import limitation across the full 24-hour window on all days in January and February instead of only during "super-peak" and "heavy-load" hours?
3. Do PSE's modeling assumptions fail to reflect expected system conditions and create artificial conditions where storage resources do not have enough energy to charge during off-peak hours, thereby reducing their capacity contribution and availability to dispatch when PSE's needs are the highest?
4. How does PSE's analysis reflect transmission constraints? Does PSE's analytical process unreasonably constrain regional transmission import limits?
5. Does PSE make the following inaccurate assumptions?
 - a. Loss of load events are consistently 24-hours in key winter months by 2027
 - b. There is 1,000 MW (or less) of Mid-C capacity (wholesale purchases) assumed to be available in key winter months by 2027, thereby making less energy available for charging storage resources
 - c. Only existing supply and any available Mid-C import capacity will be available for the energy storage to charge from, thereby excluding the possibility of storage charging from another market such as the California Independent System Operator ("CAISO").

Two-hour vs four-hour Battery

1. Are the ELCCs assigned for "Li-ion – 2-hour" (12.4% ELCC) and "Li-ion – 4-hour" (24.8% ELCC) overly conservative, considering that the resources are "stand-alone" and charging and discharging schedules will not be constrained by a co-located renewable generation resource?
2. Should such constraints be considered purely from a system perspective – not on limitations of charging and discharging to meet minimum ITC / PTC thresholds – and not result in a generic de-rate of ELCC across the board?
3. Does PSE's IRP portfolio modeling preference for two-hour battery storage conflict with the industry-standard four-hour battery?

Depth of Discharge

1. Is the Company's limitation on these storage resources' depth of discharge (DoD) overly conservative? Is a DoD value of up to 90% of the discharge capacity in ELCC modeling for the winter peak months more reasonable, in order to allow for maximum discharge during the super-peak hours?

2. In comparison to the 2020 assumptions utilized by PSE, these values are lower by 6.6% and 13.2%, respectively. What changed between the cases utilized in 2020 and amended in 2021 that resulted in this decrease in the assessed ELCC of energy storage?

Other

1. Are PSE's ELCC estimates inclusive of the possibility of forced outages during a peak event? If forced outages were included, then the ELCC valuations for thermal resources could not be the 100 percent valuations shown on Figure 4 [of the 2021 All Source RFP document].
2. How did the temperature sensitivity scenario in the 2021 IRP impact PSE's resource plan?

6. Timeline for updates

The Resource Adequacy workshop (also called the "ELCC workshop") will be held on August 31, 2021. PSE has arranged for an independent consulting firm to review its RA modeling framework. The consultant will share its observations and recommendations with PSE and stakeholders at the ELCC workshop. PSE will review the consultant's feedback and determine what updates, if any, should be made to its RA analysis. PSE will also accept written comments from stakeholders in September 2021 following the ELCC workshop, and intends to respond to stakeholder comments prior to incorporating any potential updates into the ELCC values that will be used in Phase 2 of the All-Source RFP. Depending on the recommendations and the feedback received, the process is expected to take several months. PSE would use any updates it incorporates into its ELCCs in its Phase 2 analysis of the All-Source RFP bids.

More information about the comment and response process and schedule will be provided at the ELCC workshop and on the All-Source RFP web site (www.pse.com/rfp) after the event.¹²

¹² For updates associated with the ELCC workshop, refer to the "2021 RFP Bidders' Conference and Stakeholder Workshops" section of the RFP web site (www.pse.com/rfp). The site is updated on an ongoing basis as more information becomes available.