EXH. PAH-5C
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: PHILIP A. HAINES

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-240004 Docket UG-240005

FOURTH EXHIBIT (CONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

PHILIP A. HAINES

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

FEBRUARY 15, 2024

Western Resource Adequacy Program

Cost-Benefit Analysis of Participating in WRAP

November 2022

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Background

The energy supply landscape across the western states is undergoing a major transition, leading to questions about whether the region will continue to have an adequate supply of electricity during critical hours. According to the Western Power Pool (WPP), “Numerous studies conducted over the past few years validate the concerns expressed by the [Federal Energy Regulatory Commission (FERC)] Commissioners and demonstrate an emerging problem—that the Western Interconnection will soon face a resource adequacy shortfall.”[1] Simply put, resource adequacy (RA) is the ability of supply-side and demand-side resources to meet the aggregate electrical demand including losses[2].

Three respected industry-based organizations periodically issue studies about RA in the Northwest and have raised critical concerns. The North American Electric Reliability Corporation (NERC)[3] studies regional entities and assessment areas, including Western Interconnection, Northwest Power Pool & Rocky Mountain Reserve Sharing Group, (WECC-NWPP-US & RMRG). The Western Electricity Coordinating Council (WECC)[4] evaluates resource adequacy across the entire Western interconnection (i.e., WECC) and within five subregions, including NWPP-Northwest. The Pacific Northwest Utilities Conference Committee (PNUCC)[5] specifically covers the Northwest regional planning area. All three reports cover a ten-year horizon.

Each of their most recent reports concluded that demand and resource variability is increasing rapidly, creating challenges for the bulk power system to provide reliable supply in the near-term. WECC put it most directly, stating “As early as 2025, all subregions [of the WECC] will be unable to maintain 99.98% reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power.” PNUCC concluded, “The annual energy picture reveals a regional resource deficit by next year (2023), which is three years earlier than last year’s estimate.” And NERC determined that, “The two largest U.S. assessment areas in the Western Interconnection—California/Mexico and the Northwest-Rocky Mountain—have potential for high load-loss hours and energy shortfalls for 2022 and beyond.”

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

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

The PNUCC report did not provide recommendations, but rather focused on regional trends based on an aggregation of utilities’ Integrated Resource Plan (IRP) results. Some of the trends it identified in the Northwest include:

- Increasing penetration of VERs, batteries and hybrid combinations
- Reductions in baseload (thermal) generation
- Regional demand growth due to population and electrification
- Summer peak capacity gap approaching parity with winter
- Increase in energy efficiency and demand response, i.e., demand side management

[1] ER22-2762_WRAP_Tariff_Filing
[2] NERC, 2011
[3] 2021 Long-Term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf
[4] 2021 Western Assessment of Resource Adequacy” (“WARA”), https://www.wecc.org/Administrative/WARA%202021.pdf
[5] 2022 Northwest Regional Forecast, https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf

- Transmission upgrades and additions

The WECC report recommends three major changes to RA planning:

- Calculate planning reserve margins (PRM) based on energy instead of capacity
- Use the most strained (i.e., variable) times on the system to determine PRM instead of relying on the assumption that if the peak is covered, all other times will be covered as well
- Regularly recalibrate PRMs when there are significant changes to resources or demand that may increase the variability on the system

Additionally, WECC pointed out that resource planning practices need to reflect the risk of reliance on imports in the face of increased variability in today's energy markets.

NERC's report highlighted the need for increased coordination between regulators, generators, and Load Serving Entities (LSEs), among other ideas:

- Coordination is needed between regulators, planning entities and operating entities to develop policies that prioritize reliability
- Regulators should ensure RA requirements address risks of both energy and capacity shortfalls and consider both peak and non-peak demand hours
- Regulators should address the limitations of imports in meeting peak demand during extreme weather events, which could impact fuel availability and transmission capacity
- The Electricity Reliability Organization (ERO), an enterprise comprised of NERC and North American regional entities, should collaborate with the industry to develop new processes and tools to assess and enhance RA and reliability in a world with more variability
- Generator Operators and Generator Owners as well as Balancing Authorities (BAs) should increase coordination on seasonal operating plans

Traditional RA approaches have been based solely on capacity, which worked well when most generation assets were dispatchable and demand was more predictable. The peak capacity shortfall typically occurred during the annual peak capacity hour. In today's climate, however, the drivers affecting variability in generation and load can lead to episodes of critical capacity shortfalls that do not coincide with peak demand. Focusing only on capacity fails to fully account for this variability.

Utilities, including PSE, historically have often used market transactions, including imports, to meet RA targets. Many utilities commission studies or perform their own analysis to determine the feasibility of relying on the market. However, these studies are often unable to reliably determine whether sufficient capacity will be available for purchase, or if transmission constraints would prevent capacity from reaching the intended recipient. Carvallo et al. conclude that "Regional RA studies would help utilities ensure that their assumptions about the future availability of market transactions are compatible with each other, with planned capacity additions across the region, and with the transmission capabilities of the power system."[6]

Statement of Need

The PSE IRP[7] is a planning exercise that evaluates how a range of potential future outcomes could affect PSE's ability to meet its customers' electric and natural gas supply needs. The analysis considers policies, costs, economic conditions and the physical energy system, and proposes the

[6] "Implications of a regional resource adequacy program on utility integrated resource planning", Carvallo et al., 2020
[7] Final 2021 IRP Chapter Book

starting point for making decisions about what resources may be procured in the future.

PSE is committed to reaching the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045. The goal is to reduce direct carbon emissions from PSE's electric supply by over 70 percent by 2029 and achieve carbon neutrality by 2030. PSE has also pledged to become a Beyond Net Zero Carbon energy company and to go beyond PSE's own emissions to reduce carbon emissions in other sectors by partnering with customers and industry to identify programs and products that will enable a decarbonized region. Accordingly, the PSE IRP highlights:

- Significant investments in renewable resources
- Reduced reliance on short-term market purchases in response to changing western energy markets
- Inclusion of alternative fuels to operate new generating plants

The 2021 PSE IRP determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031 as shown in Table 1. PSE has recently prepared draft RA positions based on the currently available Western Resource Adequacy Program (WRAP) planning load standards and resource Qualifying Capacity Contribution (QCC) values. The RA deficits identified in both cases, excluding the market reliance energy as capacity, are directionally consistent; confirming a significant shortfall in the RA capacity in the PSE portfolio soon after the retirement of coal resources in 2025.

Table 1 PSE Winter Peak Capacity Deficit Comparison

	Winter Peak 2027	Winter Peak 2031
PSE IRP Peak Capacity Need	907	1381
PSE IRP Short-term Market Purchases	1471	1473
PSE IRP Total Deficit	2378	2854
[redacted]	[redacted]	[redacted]

The PSE IRP states that "While the western energy market has had surplus capacity for more than a decade, PSE's 1,500 MW of firm transmission to the Mid-Columbia market hub has served as a cost-effective means of meeting demand by accessing energy supply from the regional power market. However, the supply/demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: Region-wide, the wholesale electric market is experiencing tightening supply and increasing volatility."

Significant increases in renewable resource penetration combined with retirement of traditional base load resources in the West have resulted in tighter supply/demand conditions and increased market price volatility and scarcity events. Notable events include the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip, and March 2019, when regional cold temperatures coincided with reduced Westcoast pipeline and Jackson Prairie storage availability. Most recently, in August 2020, a west-wide heat wave caused many entities in the region to take a range of actions from energy alerts to rolling blackouts.

Figure 1 highlights the increasing Energy Emergency Alerts (EEA) occurring in the Western Interconnect. These Level 3 events have occurred during extreme heat events and the increasing number of EEAs likely indicates a problem of reduced generation availability to accommodate rising demand under extreme circumstances.

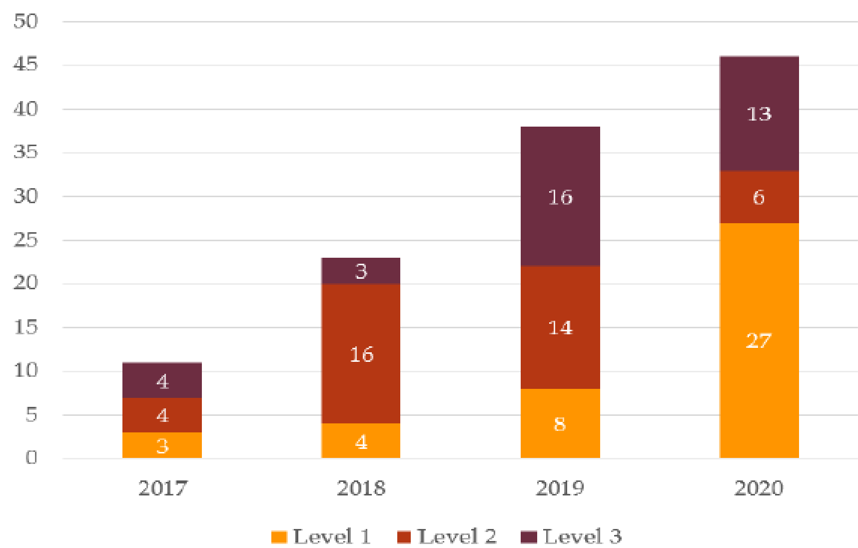

Figure 1. EEA Events by year[8]

Due to tightening supplies, increased price volatility and resource variability, the traditional methods of resource planning are unlikely to be adequate in the future. The current state of regional planning and procurement to meet capacity RA is conducted on an entity-by-entity basis. Each LSE has its own methods for calculating peak load, generation and transmission requirements and capacity contribution. New resources are approved by LSE management and evaluated by regulators relative to that LSE's needs only. Without transparency and coordination, LSEs collectively may be overly reliant on market purchases relative to actual available capacity. Additionally, in the absence of regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of Participants within the footprint during capacity critical hours (CCH).

The individualized nature of the current planning framework can make it difficult for regulators, board members, stakeholders, and utilities to understand whether, where, and when new capacity is needed in the region. To address these concerns and issues, numerous regional entities, including PSE, have started collaborating on the development of the WRAP. WRAP will increase visibility into the true status of resources and transmission and coordinate with Participants to fill in these gaps as they collectively plan for the future.

Organized Markets

A regional RA program is not a novel idea. Organized market programs cover much of North America as shown in Figure 2. Notable exceptions include the PNW, the Southwest (excluding California) and Southeast regions of the country. WRAP's footprint covers much of the PNW and Southwest.

All organized markets operate by establishing standard metrics for meeting RA needs in the market footprint. Some organized markets also feature a capacity market to meet RA targets. A brief summary of organized markets around the country excerpted from the Resource Adequacy Primer for State Regulators[9] follows.

[8] WECC State of the Interconnection - Insights and Takeaways - August 2021
[9] Resource Adequacy Primer for State Regulators – July 2021

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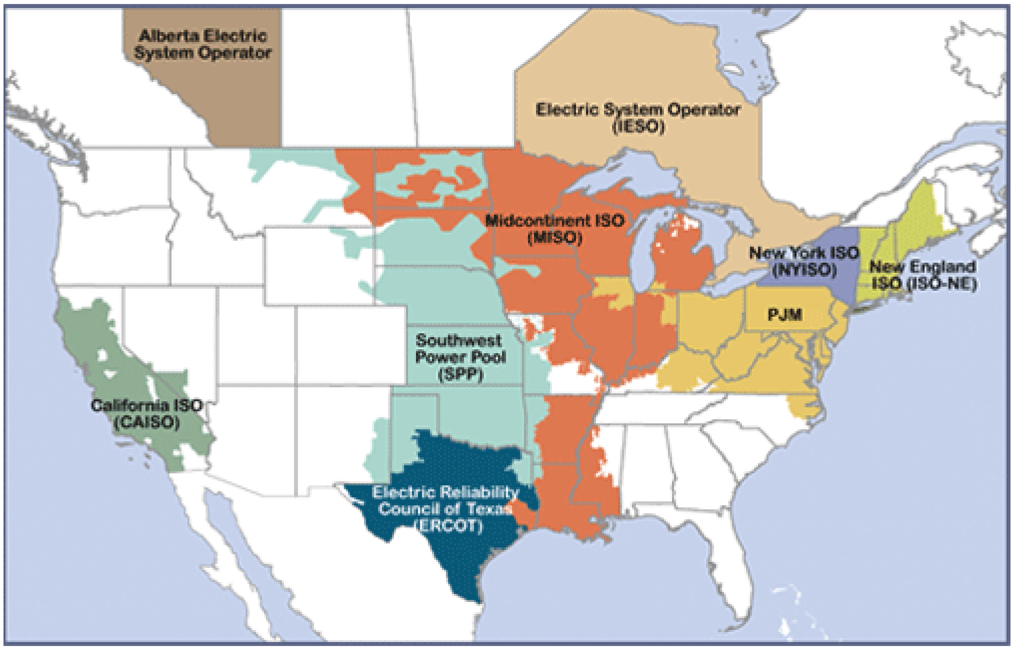

Figure 2. North American RTOs and ISOs[10]

Electric Reliability Council of Texas (ERCOT) is a single state Independent System Operator (ISO). With 75 percent of ERCOT's load served by competitive-choice aggregators, it is a unique area which only runs energy and ancillary services markets, and does not administer a capacity market. In its place, a scenario-based view of long term needs is developed by examining multiple expansion scenarios. These plans are incorporated into a 1 to 10 year planning process that encompasses transmission project decisions to inform the ERCOT reliability guidelines.

The California Public Utilities Commission (CPUC) in collaboration with the California Energy Commission (CEC) is primarily responsible for the state's RA program. The California ISO (CAISO) RA program has a Must Offer Obligation (MOO) requirement into the CAISO markets and obligates LSEs to submit RA and supply plans to the CAISO on a year ahead and month ahead basis. CAISO backstops the RA program by designating resources as Reliability Must Run (RMR) resources. Any additional shortfalls are covered through a Capacity Procurement Mechanism (CPM) which is implemented through an auction process. The RA program has three distinct components, all with annual and monthly obligations – the System RA target is 15% of forecast load, the Local RA requirement is established by an annual CAISO study incorporating weather and contingencies, and the Flexible RA is designed for ensuring adequate ramping capacity.

To achieve a certain level of RA and system reliability, ISO-New England (ISO-NE) sets a yearly system capacity requirement. This requirement is established through the Installed Capacity Requirement (ICR) calculation which accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. Forward Capacity Auction (FCA) in the Forward Capacity Market (FCM) is one of the keys to achieving and maintaining RA for ISO-NE. This market manages capacity obligations three years out through bids made in the FCA from generators, demand resources, and imports and is primarily used to secure the needed level of capacity by augmenting other market revenues.

[10] https://www.ferc.gov/power-sales-and-markets/rtos-and-isos

In the Midwest ISO (MISO) region, LSEs demonstrate sufficient resources for the coming planning year by either a fixed RA plan or by purchasing from the annual MISO planning resource auction. MISO establishes a regional and a local component of the PRM requirement for each planning zone which is a percentage of the forecast coincident peak load. For each of the planning zones, a local clearing requirement is defined and thus accounts for limits on the transmission system's ability to reliably import capacity from other zones to ensure sufficient resources are available within each zone to meet its demand at non-coincident peak conditions. MISO's RA auction is often described as a "residual auction" since a large portion of the requirements are currently met through state-level RA plans.

Pennsylvania-Jersey-Maryland (PJM) uses an annually run centralized capacity auction market called the Reliability Pricing Model (RPM) coupled with the option for LSEs to remove themselves from the auction process. PJM's existing and planned supply-side and demand-side resources and capacity imports that are deliverable into PJM are all eligible to bid into the auction. Capacity commitments for cleared resources are for the year that begins three years after the auction. As a backstop to the auction process, PJM has used reliability must-run contracts to provide specific generators with cost-of-service or avoided-cost compensation. Such contracts are offered to generation that plans to deactivate but is needed to maintain reliability until system reinforcements come online.

In the Southwest Power Pool (SPP), LSEs demonstrate compliance with RA requirements by identifying their owned resources in a submission as required by SPP's tariff or by procuring the capacity through bilateral contracts. If an LSE fails to meet its requirement, SPP will charge them a deficiency payment based on their capacity shortfall. SPP's tariff similarly requires LSEs to maintain sufficient capacity for the winter season but does not require a deficiency payment penalty for non-compliance with winter requirements. SPP determines its PRM through a probabilistic loss-of-load expectation (LOLE) study. SPP performs an LOLE study at least every two years, although it may do so more often if it determines additional studies are needed. All resources must demonstrate that capacity submitted for resource adequacy is available by meeting the appropriate qualification requirements.

The New York ISO (NYISO) uses a probabilistic analysis to evaluate RA against a 0.1 days per year LOLE criterion. A critical component of the capacity market is the New York State installed reserve margin (IRM). The IRM establishes a level of available capacity beyond the forecasted demand to address extreme weather conditions and other system impacts. The NYISO has an Installed Capacity (ICAP) market for resource adequacy designed to establish a forum for capacity through competitive auctions. These auctions are conducted on a seasonal and monthly basis.

Most of these regional planning entities establish RA standards and metrics, and several offer organized capacity markets. The notable exception is ERCOT which relies on scarcity pricing to incentivize capacity additions. Severe power disruptions in ERCOT during extreme cold weather periods in 1989, 2011 and 2021 demonstrate the reliability risk inherent in that approach.

What is WRAP[11]?

The WPP and a steering committee made up of western region market participants ("Participants") have proposed a design for a capacity-based RA Program. The WRAP is a compliance-based framework designed to increase regional reliability at a reduced cost for Participants. This voluntary

[11] Portions of this section are quoted or summarized from 2021-08-30_NWPP_RA_2B_Design_v4_final.pdf (westernpowerpool.org)

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program establishes a standardized way of approaching the RA problem across twenty-six regional entities in the west, with an estimated combined peak load of 65,000 MW.

The main components of the WRAP compliance framework are the Forward Showing (FS) Program and the Operational (OPS) Program for both winter and summer seasons. These programs seek to achieve a balance between planning in a reasonably conservative manner and providing the flexibility to protect customers from unreasonable costs.

The FS program establishes regional metrics for the footprint, sets the QCC of various resources, sets deliverability expectations and determines planning windows for demonstrating adequacy. Participants are required to show that they have contracted for the required amount of capacity resources to meet a 1 in 2 peak event (P50) plus a PRM. They must also demonstrate that they have firm transmission rights to deliver at least 75% of their FS resources. The FS deadline for demonstrating adequate capacity and transmission is seven months prior to the beginning of each summer or winter season. The first binding season that a participant may elect is summer 2025. Participants must commit to go binding by winter 2027-2028 to continue in the program.

The OPS program creates a framework to provide Participants with pre-arranged access to capacity resources in the program footprint during times when a Participant is experiencing an extreme event, such as excess load or forced outages. A key benefit WRAP provides is the ability to leverage the load and resource diversity within the region, meaning LSEs have the potential to carry less PRM during the FS planning window than they would on a stand-alone basis. The OPS Program allows Participants to collectively manage risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

WPP has conducted an extensive public outreach process over the past few years to create a governance structure designed to give stakeholders a voice in decision-making. Since certain WRAP elements will be subject to FERC oversight, WPP's Board of Directors has been restructured to ensure its independence. A Resource Adequacy Participants' Committee (RAPC) is the highest level of authority for Participants, allowing them to vote on policies, processes, and more. The Committee of State Representatives (COSR) includes one representative from each state or provincial jurisdiction. The purpose of this committee is to gain the perspectives of regulators and policy makers on energy matters, and to provide a forum for them to gain a better understanding of how the program works.

Business Case Framework

RA impacts planning, execution and costs for a variety of stakeholders inside and outside of the utility. In order to define a common standard and take into account the perspectives of these stakeholders, a Business Case (BC) framework defines the goals, objectives and methodologies used to validate PSE's RA strategy.

The intent of this framework is to follow the guidelines of basic prudent utility practice.

- Document the Need
- Evaluate alternatives to meet the Need
- Determine the alternative that best meets the Need from the customer's perspective
- Re-evaluate as new information becomes available

PSE engaged a consultant, Energy GPS (EGPS), to review and validate the assumptions for this framework, develop models, gather data and define inputs and outputs for the final result. The following sections, including ‘Goals, Objectives and Methodologies’, ‘Results and Discussion’, and ‘EGPS Summary’, were prepared by EGPS.

Goals, Objectives and Methodologies

The overarching goal of this project is to determine the costs, benefits, and risks of PSE joining the WRAP as compared to a) prior long-term methods for assessing RA and b) expected future long-term methods where PSE does not join the WRAP.

The following objectives meet this goal:

- Objective 1. Develop a framework to analyze the costs, benefits, and risks of joining the WRAP. The framework evaluates three alternatives: 1) Business As Usual (BAU), 2) PSE does not join the WRAP (WRAP-Out) and 3) PSE joins the WRAP (WRAP-In).

- Objective 2. Using the framework, quantify the peak load, PRM, and QCC for each PSE resource under each alternative.

- Objective 3. Quantify costs/revenues of RA purchases/sales using forward RA curves. Provide opinion on the market depth of RA purchases/sales for each alternative and associated risks.

Methodologies

To meet objective 1, we developed a Microsoft Excel model to serve as the framework for the analysis. The model allowed us to quantify, for each binding season, the firm capacity requirements (P50 peak load forecast plus PRM), the available firm capacity (sum of the QCC for each resource), and the RA position (available capacity less firm capacity requirements). We designed the model to take inputs for each month of each binding season (i.e., summer, winter) for one future year. The model evaluated each of the three alternatives.

To meet objective 2, we populated the model for the binding year of 2026 with data obtained from the PSE 2021 IRP for the BAU alternative, draft data from the PSE 2023 Energy Progress Report (EPR) for the WRAP-Out alternative, and draft data from the WPP WRAP model for the WRAP-In alternative. The binding year 2026 was selected because it is the first binding year after the Colstrip coal retirement. Each of these alternatives contains input data under different assumptions. We documented the definitions and assumptions in the underlying data for each alternative in Table 2. Our expectation is that the final data for the 2023 EPR and WRAP alternatives will not significantly change from the current estimates.

Table 2. Methods used to determine load, PRM, and QCC for each alternative

	BAU (2021 IRP)	WRAP-Out (2023 EPR)	WRAP-In (WRAP)
Peak Load	30-year historical temperature	P50 based on Fiscal Year 2022 (F22) forecast by season	Historical 5-year P50 data escalated by 1.1% annually by season
PRM	Resource Adequacy Model (RAM), 5% Loss of Load Probability (LOLP)	E3 study based on climate model inputs	LOLE 1 day in 10 years
QCC: Thermal	Effective Load Carrying Capability (ELCC)	ELCC	Unforced Capacity (UCAP)
QCC: Wind & Solar	ELCC	ELCC (E3 with climate change data)	ELCC
QCC: Hydro	ELCC	ELCC (E3 with climate change data)	Storage hydro model
QCC: Storage	ELCC	ELCC (E3 with climate change data)	5-hour duration requirement
QCC: Other	ELCC	ELCC (E3 with climate change data)	5-hour duration requirement
QCC: Contracts	1500 MW reliance on market power	Declining reliance on market power	No reliance on market power

To meet objective 3, we developed RA price curves for the WPP to quantify costs for market RA purchases. We used our WECC-wide production cost model (PCM) to forecast supply/demand balances in the WPP region shown in Figure 3. The RA price is determined by the "missing money" or make-whole payment for the existing marginal capacity resource in the WPP unless: 1) recent trade data is available, or 2) equilibrium is reached where the minimum PRM is met, at which point the RA price is set as the net Cost of New Entry (CONE) of a combustion turbine (CT) unit.

Figure 3. WECC reliability regions

Results and Discussion

Underlying Assumptions

The notable differences between inputs for load, PRM and QCC for each alternative are:

BAU (2021 IRP):

- The BAU case based on the 2021 IRP does not differentiate between summer and winter binding seasons; only the winter peak from December was used for planning based on a peak load using 30-year historical temperature data
- The PRM was estimated using an in-house resource adequacy model targeting a 5% LOLP for the year 2027
- The BAU case relies significantly on nearly 1,500 MW of market purchases to maintain reliability

WRAP-Out (2023 EPR):

- Considers a forecasted summer and winter peak separately
- Resource QCCs are estimated for each season
- Load is based on a peak load forecast for winter and summer planning periods
- PRM is based on meeting a 5% LOLP using a climate change model for inputs
- ELCCs for wind and solar are based on modeling by E3 using climate model derived inputs for one future year

WRAP-In:

- Load requirements are based on median or P50 peak of five years of historical peak load data that is forecasted to a future year by applying a 1.1% annual average growth rate
- PRM is derived from P50 load forecast submissions by Participants to meet a 1 day in 10 years LOLE
- Summer and winter binding seasons are considered separately with monthly requirements during each season
- A regional model is used to derive capacity contributions for VERs

For this report, the focus is on the differences between the WRAP-In and WRAP-Out alternatives. As PSE moves toward planning for a separate summer and winter peak, similar to WRAP, this is the most relevant comparison. BAU is no longer a valid alternative but is included for context.

Summer Season Results

The summer season results for Jun 2026 through Sep 2026 are shown in Table 3. The lower peak load forecast is driven by differences in methodology with the WRAP using a simplified annual growth rate applied to historical peak load. The lower PRM is likely due to three factors, 1) regional diversity benefits, 2) methodological differences, and 3) WRAP's observation that compared to the winter load shape with two peaks (i.e., morning and evening) and more hours exposed to loss of load, the summer load shape has a single peak, less exposure to loss of load, and therefore a lower PRM. The combination of lower peak load and lower PRM means the capacity requirement for the WRAP-In alternative is lower than the WRAP-Out alternative. The resource QCCs are higher for the WRAP-In alternative with the exception of hydro and power purchase agreement (PPA) contracts. These differences result in a RA benefit of [redacted] MW for WRAP-In as compared to WRAP-Out. Assuming an RA price of $[redacted]/kW-mo for WRAP-In, an RA price of $[redacted]/kW-mo for WRAP-Out, and a four-month binding season, RA savings are estimated at $[redacted] million for Summer 2026.

Table 3. Summer 2026 capacity requirements, capacity contributions, and capacity deficit for each alternative

Alternatives	BAU (2021 IRP)	WRAP-Out (2023 EPR)	WRAP-In (WRAP)	WRAP-In less WRAP-Out
Year	2026	2026	2026	2026
Season	Annual	Summer	Summer	Summer
Peak Load (MW)	(4894)	(3806)	[redacted]	
PRM (%)	20.7%	23.9%		
Capacity Requirement (MW)	(5907)	(4717)		
Resource QCC (MW)				
Thermal	2050	1692		
Wind and Solar	396	78		
Hydro	778	928		
Storage	0	0		
PPAs	211	173		
PG&E Exchange	(300)	(300)		
Market Reliance Capacity (MW)	1476	0		
Capacity Available (MW)	4611	2571		
Capacity Surplus (Deficit) (MW)	(1296)	(2146)		
RA Price ($/kW-mo)	[redacted]			
RA Cost ($ millions)				

†Positive value indicates a benefit of WRAP-In through lower peak load and/or capacity requirements

Winter Season Results

The winter season results for Nov 2026 through Mar 2027 are shown in Table 4. The lower peak load forecast is due to methodological differences. The lower PRM is driven by the WRAP regional LOLE analysis demonstrating that increasing load and resource diversity requires a lower PRM. The capacity requirement for the WRAP-In alternative is lower than the WRAP-Out alternative because of a lower peak load forecast and lower PRM requirements. The resource QCCs are lower overall for the WRAP-In alternative with increased QCC from wind and solar offset by lower QCC from thermal, hydro, and PPAs. All together, these differences result in a [redacted] MW RA benefit for WRAP-In compared to WRAP-Out. Assuming an RA price of $[redacted]/kW-mo for WRAP-In, an RA price of [redacted]/kW-mo for WRAP-Out, and a five-month binding season, RA savings are estimated at $[redacted] million for Winter 2026 with the WRAP-In alternative.

Table 4. Winter 2026-2027 capacity requirements, capacity contributions, and capacity deficit for each alternative

Alternatives	BAU (2021 IRP)	WRAP-Out (2023 EPR)	WRAP-In (WRAP)	WRAP-In less WRAP-Out
Year	2026	2026	2026	2026
Season	Annual	Winter	Winter	Winter
Peak Load (MW)	(4894)	(4600)	[redacted]	[redacted]
PRM (%)	20.7%	23.8%	[redacted]	[redacted]
Capacity Requirement (MW)	(5907)	(5695)	[redacted]	[redacted]
Resource QCC (MW)			[redacted]	[redacted]
Thermal	2050	2072	[redacted]	[redacted]
Wind and Solar	396	148	[redacted]	[redacted]
Hydro	778	859	[redacted]	[redacted]
Storage	0	0	[redacted]	[redacted]
PPAs	211	120	[redacted]	[redacted]
PG&E Exchange	300	300	[redacted]	[redacted]
Market Reliance Capacity (MW)	1476	0	[redacted]	[redacted]
Capacity Available (MW)	5211	3498	[redacted]	[redacted]
Capacity Surplus (Deficit) (MW)	(696)	(2197)	[redacted]	[redacted]
RA Price ($/kW-mo)	[redacted]	[redacted]	[redacted]	[redacted]
RA Cost ($ millions)	[redacted]	[redacted]	[redacted]	[redacted]

†Positive value indicates a benefit of WRAP-In through lower peak load and/or capacity requirements

Evaluation of WRAP Benefits

The WRAP benefits to PSE are significant assuming the WRAP provides the same or increased reliability compared to current planning. The benefits come in the form of lower capacity requirements due to lower peak load forecasts and lower PRM requirements. This is consistent across both the winter and summer binding seasons with larger benefits in the summer.

The large reductions in PSE peak load forecasts, particularly in the summer, are driven by different forecasting and current single season planning methodologies. Joining a regional program will lower PRM requirements for members due to load and resource diversity and capacity sharing subject to transmission constraints. The amount of PRM reduction is uncertain, however, and the reductions shown in the WRAP estimates for summer, from [redacted]% to [redacted]%, on average, are considerable. In SPP's view, this is due to summer demand having one peak during the day while winter demand typically has a morning and evening peak thus leading to more exposure to a loss of load event and requiring a larger PRM.

Sensitivity Analysis

The PRM benefits of the WRAP may or may not be fully realized as currently forecasted by WPP, so we performed a sensitivity analysis to understand the potential impact on capacity cost benefits. We evaluated the cost savings under an incremental increase of 20% and 40% of the WRAP PRM. This analysis was conducted with two different load scenarios, a) using the original WRAP load forecast and b) substituting the higher PSE load forecast. As shown in Figure 4 and Figure 5, a positive capacity cost benefit is realized even as the PRM is increased under either load scenario. In fact, WRAP-In PRM would have to double to reach a break-even point with WRAP-Out for the 2026 binding year when using the WRAP load forecast.

[redacted]

[redacted]

Resource Adequacy Price Curves

RA prices can be estimated using supply and demand balances; however, historical RA prices have been very sensitive to slight changes in supply and demand. For example, recent prices in California have ranged from $4 to $11/kW-mo. We have provided four RA price curves in the WPP in Figure 6 to illustrate this uncertainty.

First, the highest price curve is the “New Build Capacity Price” and is based on the CONE for an F class CT unit. We derive the cost for this unit from the National Renewable Energy Laboratory (NREL) Advance Technology Baseline (ATB) cost forecasts. Payments are annualized using a 5.3% cost of capital assumption and a 30-year lifetime.

Second, the “Marginal Price” represents the make-whole payment for existing units from 2025 to 2030 as generated by EGPS’s PCM. Prices are interpolated prior to 2025. Prices after 2030 are based on the net CONE of the F class CT unit assuming energy revenues from the PCM forecast. This represents the marginal capacity price unit.

Third, production cost models typically over-optimize prices and do not capture scarcity price volatility as seen in actual real time prices. Energy revenue estimates for CT units are typically biased toward the low end resulting in higher make-whole payments and higher RA prices. To compensate for this, we derived a scarcity price adder and applied additional scarcity price revenue resulting in the lower RA price curve, referred to as “Marginal Scarcity Price”.

Fourth, the existence of the WRAP may lead to increased market transparency and price discovery that may lower RA prices across the west for WRAP Participants. To estimate “Marginal Price without WRAP”, we applied a 15% premium to the net CONE price representing an RA price if PSE does not join the WRAP. This premium is based on the professional judgement of EGPS and represents approximate differences in RA prices between different thermal technology types (i.e., fixed capital costs differences between a CT and combined cycle) in the case that the most cost-efficient RA resource is not available for bilateral transactions.

Finally, the “CA Mid Forecast” is included as a reference. The CA Mid Forecast was derived from make-whole-payments from 2025 to 2027, and the CPUC‘s Soft Offer Cap (SOC) payment from 2028 onwards.

[redacted]

RA prices show significant variability across markets and across time. ISO prices depicted in Figure 7 were obtained from publicly available auction clearing results for MISO, NYISO, PJM, and ISO-NE. California prices were obtained from historical bilateral trade data. The marginal capacity unit sets the price in the auction clearing models. The marginal unit is generally determined by a supply-demand curve where demand equals the RA capacity requirement. If excess reliable capacity is available, the price trends towards zero. If the market is short of reliable capacity, the price generally trends to the CONE of a new unit. Prices in this study range from $0.15/kW-mo to $11/kW-mo.

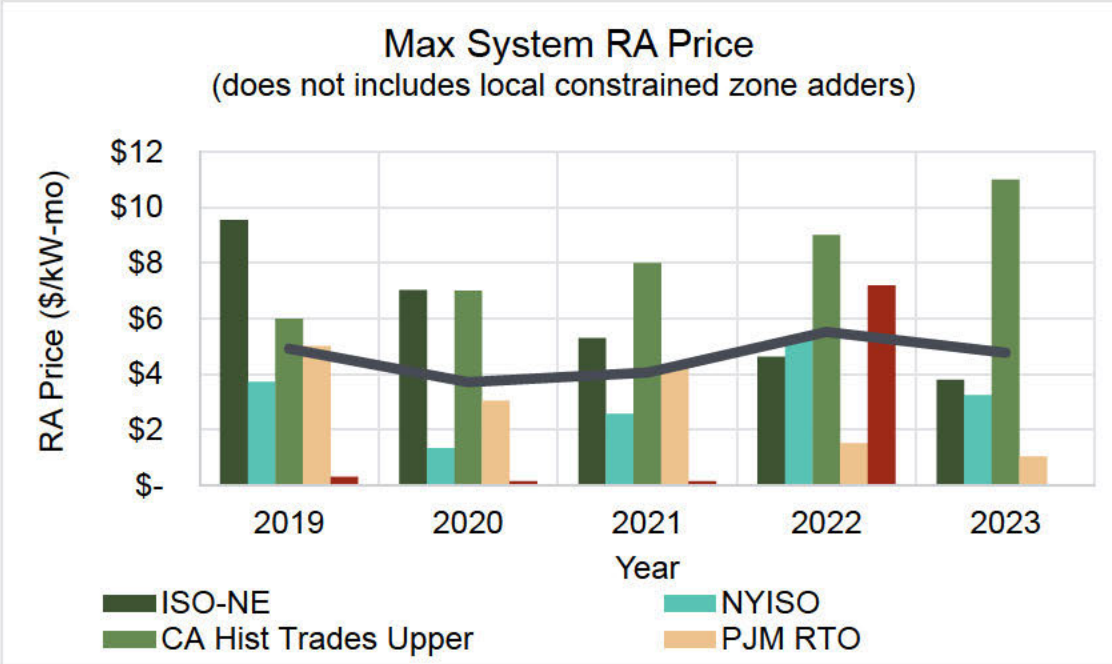

Figure 7. Historical maximum RA prices from various ISOs in the U.S

Qualitative Risks and Benefits of Joining the WRAP

Qualitative benefits of joining the WRAP include reductions in reliability risk, price risk, modeling risk, investment risk, and regulatory risk. This section explains how the WRAP could reduce risk or potentially increase risk across these categories, and addresses risk mitigation factors.

Reliability and Compliance Risk

Reliability risk is the risk that PSE cannot serve load. The WRAP is likely to lower the reliability risk due to the transparency of the FS program which ensures that all Participants have adequate capacity to meet load plus PRM requirements. The FS program is designed to ensure that adequate transmission is available for each Participant in advance of the OPS program. During the OPS program reliability risk is reduced through binding capacity-sharing obligations in the Day Ahead market.

The WRAP may increase reliability risk if load forecasts, PRM, and QCC as modeled by the WRAP significantly change from the FS estimates. For example, the region is seeing significant load growth due to adoption of air conditioners during the summer months in the PNW. If the simple method of the WRAP load forecast does not capture these rapid increases, the amount of capacity required will be underestimated and thus reliability may decrease. If QCC values are overestimated, the regional reliability may decrease.

Additionally, there is an increased compliance risk in the event that PSE fails to meet its obligations in the FS or OPS programs. Participants who do not meet those obligations are subject to significant deficiency payments as a disincentive.

Price Risk

Price risk is the risk of commodity price volatility. Scarcity pricing occurs during tight market conditions

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to ensure blackouts are avoided. In energy-only markets such as ERCOT, scarcity pricing serves as a price signal to reward capacity. As regional reliability is improved through the FS and OPS programs, the likelihood of scarcity pricing events should decrease, resulting in lower price risk.

The WRAP may increase price risk if reliability does not improve as discussed above and tight market conditions occur more frequently.

Modeling Risk

Modeling risk may occur due to using methods or inputs that are not consistent with industry or regional standards or errors in model inputs or methods. The WRAP will promote the use of a common modeling framework, input assumptions, and analysis to determine reliability across the region. This central modeling framework will allow for inputs from a broad range of stakeholders and will be facilitated by SPP, leading to increased quality assurance.

The WRAP may increase the modeling risk if the techniques adopted prove not to be appropriate for quantifying reliability, load growth, and QCC.

Investment Risk

Investment risk is the risk of spending more capital than required to maintain reliability. The WRAP could reduce the investment risk for individual Participants through improved regional planning efforts and analysis. For example, SPP has performed regional QCC studies based on the penetration of resources by zone and resource type (e.g., wind, solar), showing that as penetration increases, QCC decreases. Access to this information may allow for more efficient investments.

The WRAP may increase the investment risk if the QCC metrics for a resource are understated thus skewing the capacity value of the resource too low.

Regulatory Risk

Regulatory risk is the risk of inadequate cost recovery through regulatory processes (i.e., not getting rate base cases approved). Regulatory risk of individual Participants is likely to be reduced by joining the WRAP. The transparent nature of the WRAP's methods and planning process, as well as regional stakeholder engagement, should promote buy-in from regulators and other external stakeholders. A common set of input assumptions and models is likely to create a smoother regulatory environment for review and approval of mid-term and long-term planning.

The WRAP may increase the regulatory risk of an individual Participant if the methods used are not broadly adopted by the regulatory body.

Risk Mitigation Factors

WRAP has a robust governance structure that promotes stakeholder input and provides for checks and balances in case the program is not performing optimally. A Program Review Committee (PRC) is a stakeholder group that proposes design modifications. The Independent Evaluator (IE) assesses WRAP performance and can also recommend design modifications. The RAPC allows Participants to vote on policy and process changes. An independent Board of Directors approves design changes, and approves the PRM each season. The COSR offers regulatory bodies the chance to weigh in and participate. As the program matures, the WRAP has committed to continuous improvement and refinement of its methods.

The WRAP offers an extensive on-ramp before Participants must opt into the fully binding program. This lessens exposure to compliance risk, and allows the program to mature during the non-binding phase (now through Summer 2025) and the transition phase (Summer 2025 through summer 2028). Participants may opt out of the program with two years' notice, giving companies a way out if they find the program is not performing as anticipated, or if they believe they won't meet the binding obligations.

Finally, WRAP does not replace the long term planning function of LSEs. WRAP sets a minimum reliability standard for the near term, 7 to 12 months ahead. PSE can mitigate reliability, modeling and investment risks by procuring capacity based on a combination of in-house modeling and WRAP methods and by procuring capacity from a variety of technologies so no technology QCC metric is overly relied upon. Additionally, Participants can always aim for a higher standard, recognizing that there could be regulatory risk implications of procuring excess capacity.

EGPS Summary

This study evaluated the costs and benefits of joining the WRAP by examining three alternatives: 1) a BAU alternative using the 2021 IRP assumptions, 2) a WRAP-Out alternative using the 2023 EPR assumptions, and 3) a WRAP-In alternative using the WPP WRAP assumptions. We focused on the differences between the WRAP-In and the WRAP-Out alternatives because both differentiated between summer and winter reliability targets while the 2021 IRP only focused on winter reliability.

We found significant capacity cost savings by joining the WRAP due to lower peak load forecasts and lower PRM requirements. Under WRAP-In, the QCC of resources increased in the summer and decreased in the winter but was not a significant driver of benefits either way. In the summer season (Jun 2026 through Sep 2026) this equated to $[redacted] million dollars per year in savings. In the winter season (Nov 2026 through Mar 2027) this equated to $[redacted] million dollars per year in savings.

A sensitivity analysis was conducted to understand the impact if the full PRM reductions forecasted by the WRAP do not materialize. The PRM requirement was incrementally increased to 20% and 40% of the baseline PRM. In both cases positive benefits were realized by joining the WRAP. The PRM would have to increase to over 200% of current estimates for the capacity cost to reach a breakeven point with the WRAP-Out alternative for the 2026 planning year.

We identified several qualitative benefits of joining the WRAP. In general, a regional RA program should increase reliability at lower costs by leveraging load and resource diversity to reduce the PRM. A key feature of the WRAP is the OPS program where capacity resources are shared among Participants to meet tight supply-demand balances. Scarcity pricing events should be less frequent with the enhanced reliability the WRAP provides. Lower regulatory risk should exist in a regional program through the broad stakeholder participation and the use of a consistent and transparent modeling, assumption, and analytical framework.

PSE Conclusion

Decarbonization efforts plus fossil fuel retirements along with increased VER penetration are leading to increased reliability risk in the west. Organized markets in much of North America establish RA standards and metrics, and often offer capacity markets. The WECC-NWPP-US & RMRG region is a notable exception where no such organization is in place.

WRAP addresses this need through a voluntary compliance-based framework that increases reliability at a potentially reduced cost for participants throughout the western region.

PSE developed a business case framework to evaluate the costs and benefits of participating in WRAP. PSE hired consulting firm EGPS whose analysis shows significant capacity cost savings may be realized by joining the WRAP. The primary drivers for these savings are a lower capacity requirement (volume) and lower RA capacity cost (price). Additional qualitative benefits include risk reduction across several categories, including reliability, price, investment, modeling and regulatory. Although WRAP participation has the potential to increase risk in each of these areas, those risks can be mitigated through the WRAP's governance structure, the lengthy transition from non-binding to fully binding seasons, the ability of Participants to model reliability in parallel with WRAP, and by the ability to delay entry or even exit the program with two years' notice.

In September 2022, PSE's Energy Risk Management Committee (ERMC) approved the business case framework, reviewed the cost benefit analysis and approved a motion to join the WRAP. That decision and a review of the business case and cost-benefit analysis was presented to PSE's Board of Directors in November 2022. Front Office recommended winter 2027-2028 as PSE's first binding season to allow maximum flexibility and runway to acquire qualifying capacity to meet the WRAP requirements. This was presented without objection to the following groups: Regulatory, Mid-Office, Resource Acquisitions and IRP.

Appendix A: Acronyms

Acronym	Definition
ATB	Advance Technology Baseline
BA	Balancing Authority
BAU	Business As Usual
BC	Business Case
CAISO	California ISO
CCH	Capacity Critical Hours
CEC	California Energy Commission
CETA	Clean Energy Transformation Act
CONE	Cost Of New Entry
COSR	Committee Of State Representatives
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CT	Combustion Turbine
EEA	Energy Emergency Alerts
EGPS	Energy GPS
ELCC	Effective Load Carrying Capability
EPR	Energy Progress Report
ERCOT	Electric Reliability Council Of Texas
ERO	Electricity Reliability Organization
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FS	Forward Showing (Program)
F22	Fiscal Year 2022
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IRM	Installed Reserve Margin
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO-New England
LOLE	Loss-Of-Load Expectation
LOLP	Loss-of-Load Probability
LSE	Load Serving Entity
MISO	Midwest ISO
MOO	Must Offer Obligation
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York ISO

OPS	Operational (Program)
PCM	Production Cost Model
PJM	Pennsylvania-Jersey-Maryland
PNUCC	Pacific Northwest Utilities Conference Committee
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
P50	1 in 2 Peak Event or 50th Percentile
QCC	Qualifying Capacity Contribution
RA	Resource Adequacy
RAM	Resource Adequacy Model
RAPC	Resource Adequacy Participants' Committee
RMR	Reliability Must Run
RPM	Reliability Pricing Model
SOC	Soft Offer Cap
SPP	Southwest Power Pool
UCAP	Unforced Capacity
VER	Variable Energy Resource
WECC	Western Electricity Coordinating Council
WECC-NWPP-US & RMRG	Northwest Power Pool & Rocky Mountain Reserve Sharing Group
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program