BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-136:
WECC Explainer

WECC

Electric Reliability and Security for the West

ODITY Threshold Interpretations

October 25, 2022

What is the ODITY Threshold?

In planning, "one day in ten years" (ODITY) represents the maximum acceptable amount of time electricity generation can be at risk of being short of demand and still be considered adequately reliable.

How is the ODITY Threshold measured?

Many utilities incorporate the ODITY threshold into their long term, integrated resource planning methods by bringing it down to an annual level of temporal granularity. One day in 10 years, or 24 hours in 10 years, is often averaged to a maximum of 2.4 hours of risk allowed per year for a portfolio of resources to be considered sufficiently reliable.

WECC takes the ODITY maximum down to the hourly level to set thresholds in its probabilistic assessments of resource adequacy. This interpretation yields a threshold for each hour needing to demonstrate sufficient resource availability to meet demand 99.8% of the time.

Why does WECC use the ODITY threshold on each hour?

WECC chooses to look at the ODITY threshold for each hour rather than averaged over each year:

- To accurately account for risk;
- To study variability hour to hour; and
- To improve assumptions of import availability.

ODITY in Probabilistic Assessments: Accounting for Risk

WECC uses hourly shaped, bell curve probability distributions of demand next to those of energy availability by resource type to measure reliability.

For each hour, the distributions are compared to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions can then calculate as a loss of load probability (LOLP). This is the cumulative probability associated with the overlap.

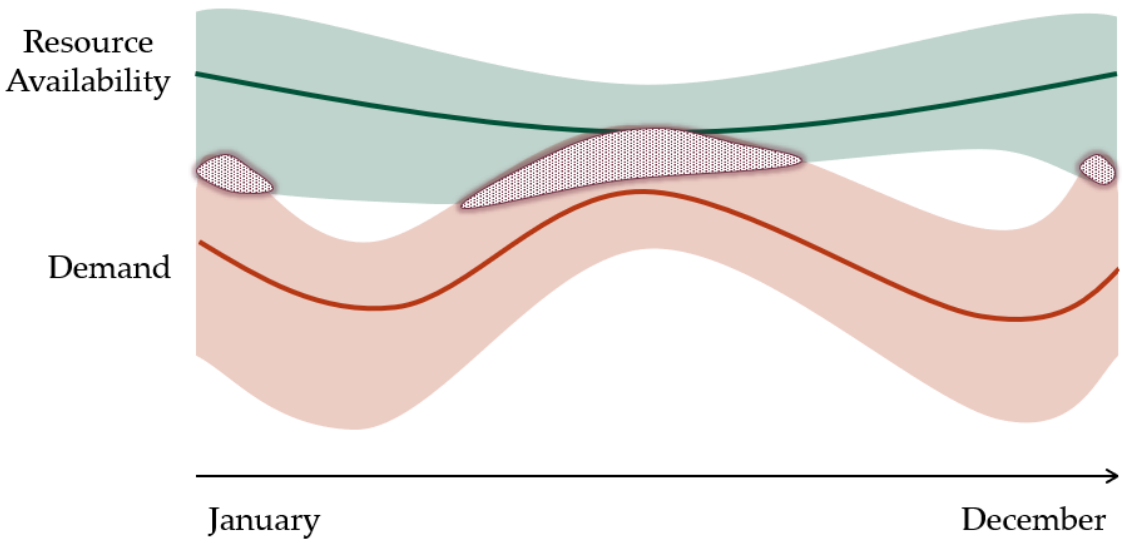

Figure 1: Annual Distribution Ranges of Demand and Resource Availability

If the probability of the resource availability falling below demand is greater than a certain threshold—in this case more than 0.02% for one of the hours—WECC notes there is a reliability shortfall in that area for that hour. A reliability threshold reserve margin (in megawatts) can be calculated to determine the shortfall in need of amelioration to maintain a level of LOLP at or less than the threshold.

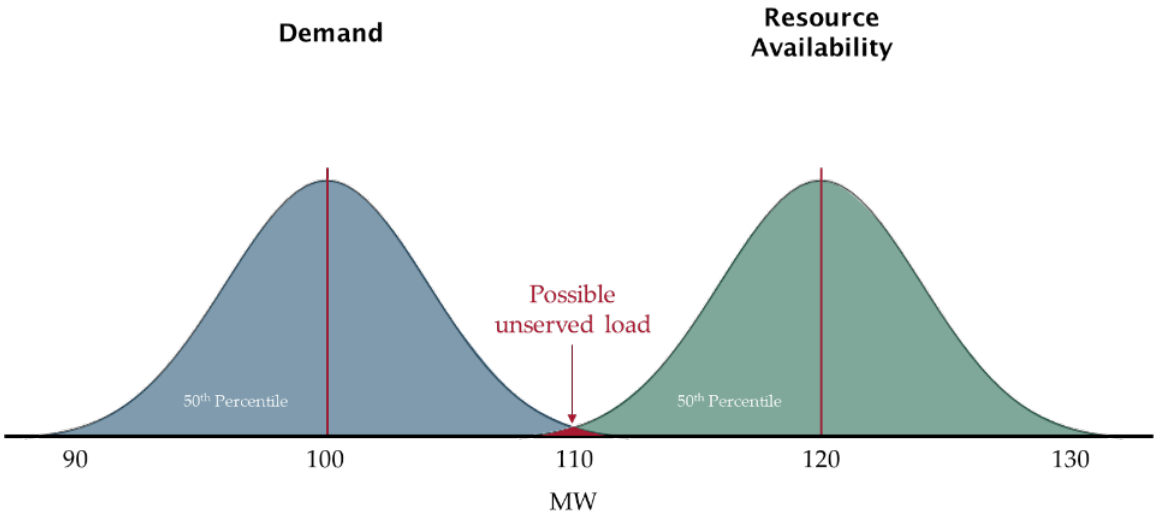

Figure 2: A Single Hour's View of the Probability Distributions of Demand and Resource Availability

Hourly Variability

Over 80% of new electricity capacity are renewables.[1] Concurrently, climate change is contributing to record peak demand by skewing the probability of previously rare weather, like widespread and long-lasting heat dome events.

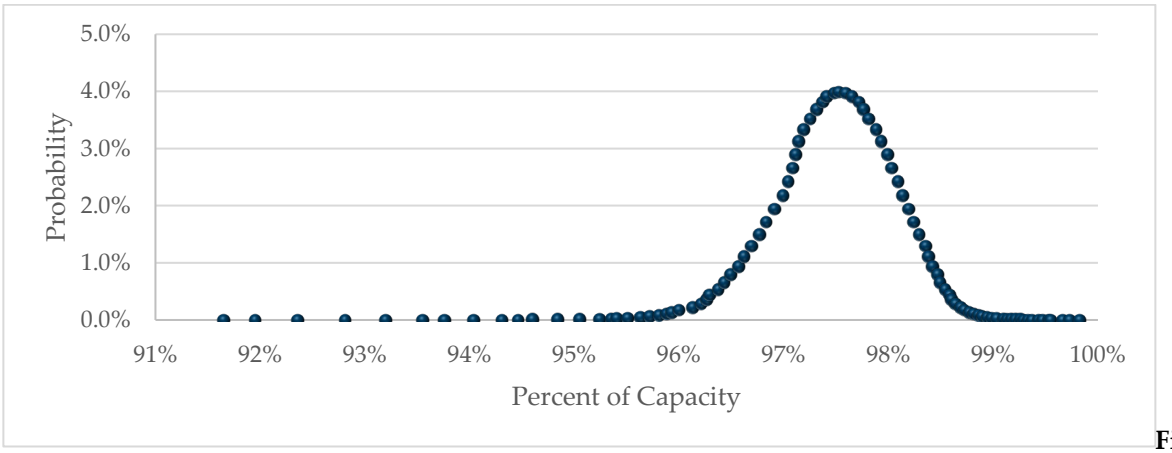

Figure 3: Baseload Availability Probability Distribution Example

Historically, electricity demand peaked on weekdays in the early evenings when many people get home from work. This timing typically coincides with a setting sun. So, just as electricity system operators are looking for resource availability to ramp up generation to meet the spiking demand, at least the solar resources' availabilities are dropping.

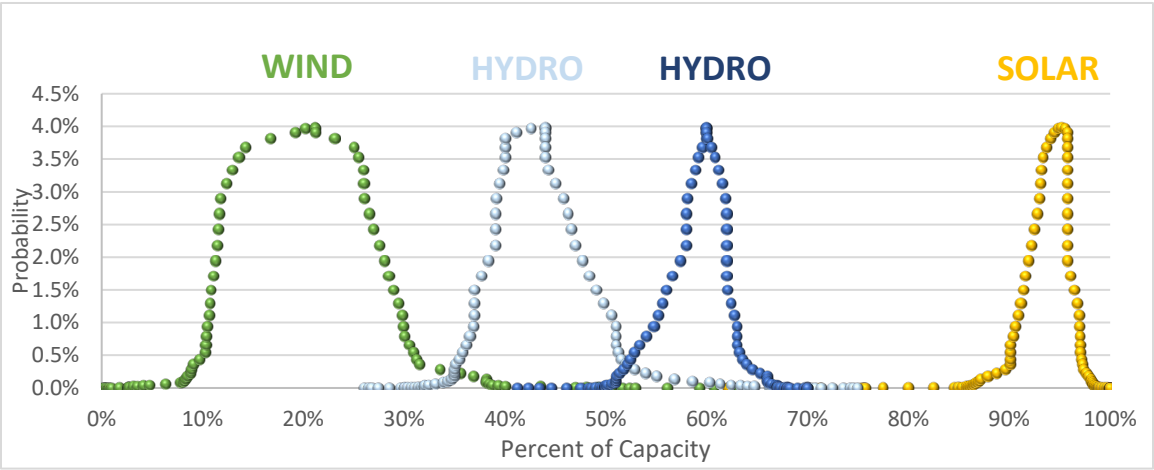

Figure 4: Renewables' Availability Probability Distributions Example

To combat the ramping risk, many planners are turning to long-term energy storage, either via hydro reservoirs, utility-scale batteries, or the incorporation of other new technologies like hydrogen, as well

1 Some good news on energy—The New York Times (nytimes.com) October 25, 2022

as the traditional use of natural gas peaker plants. The combinations of new and conventional resource types make new shapes of availability.

WECC is interested in looking at every hour so this aspect of a changing system is regularly analyzed to ensure reliability and spot potential issues years in advance.

Imports' Availability Assumptions

The West's system is large, and its diversity increases reliability because Balancing Authority Areas (BAA) can often rely on each other for imports. In planning, sometimes a limit is set for how many megawatts of imports will be available.

Since WECC collects loads and resources information from all of the BAAs throughout the West, and conducts probabilistic assessments of availability and demand, WECC can see when and where imports may not be sufficient to cover shortfalls of internal availability to meet demand.

Doing this analysis at the hourly level provides greater insights by identifying specific situational risk.

Conclusion

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the probabilistic calculations depends on the system and the desired output that is being analyzed. In the Western Interconnection, a system that is geographically diverse and depends on transfer capabilities, WECC developed the Multiple Area Variable Resource Integration Convolution (MAVRIC) model to enhance its probabilistic capabilities. Using convolution techniques, Monte-Carlo simulations, and the ability to use transfers dynamically, MAVRIC can better model the overall reliability of the Western Interconnection while maintaining adequate run-time and computing capabilities.

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Exhibit 1-137:
Power Council 2029 Power Supply Adequacy Assessment

Pacific Northwest Power Supply Adequacy Assessment for 2029

Northwest **Power** and **Conservation** Council

August 2024 | document 2024-4

2029 Adequacy Assessment

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Forward

The Council's annual adequacy assessment is a five-year test of the power plan's resource strategy to ensure that it will provide an adequate future power supply. This report summarizes the Council's assessment of the aggregate regional power supply's adequacy for the 2029 operating year (October 2028 through September 2029).

Analytical results are based on the Council's GENESYS model, which performs a Monte-Carlo chronological hourly simulation of the power system's operation over an entire year. Each study simulates the year's operation many times with different combinations of river flows, temperatures (demand), and wind and solar generation. Projected future river flows, temperatures, and wind generation are derived from climate change data for the Pacific Northwest. The Resource Adequacy Advisory Committee (RAAC), the System Analysis Advisory Committee (SAAC), and other stakeholders played an important role in updating resource and load data, reevaluating operating assumptions, and carefully reviewing the model's power system simulation.

In 2011, the Council adopted a 5 percent annual loss-of-load probability (LOLP) as its measure for adequacy. The power supply was deemed to be adequate when the likelihood of one or more shortfalls occurring during the year is no greater than 5 percent. However, the Council recognizes that today's power system is very different, where significant increases in variable energy resources, such as solar and wind, have added a greater band of uncertainty in system operations. This and other shifts in the power supply, such as increases in distributed generation and changing electricity markets, have made system operations much more complex.

To address this, the Council has enhanced its adequacy model, GENESYS, by significantly improving hourly hydroelectric operations; adding a better representation of unit commitment and balancing reserve allocation; better reflecting electricity market dynamics; and adding other enhancements to more accurately mimic real-life operations. Because of the increasing complexity of the power system and because of the limitations of the LOLP metric, it was imperative the Council also enhance its adequacy standard to capture a more precise measure of customer risk.

To this end, in 2023 the Council transitioned to a more comprehensive multi-metric framework to represent the risk of shortfall frequency, duration, and magnitude, which will be described later in this report. A resource adequacy assessment is only a relative measure of customer risk. It does not draw a bright line between a system with no risk and one with risk. An "adequate" system is not immune to resource shortfalls nor is an "inadequate" system certain to have them. By examining additional adequacy measures, the Council can assess the adequacy of the regional power supply more precisely.

Executive Summary

Over the next five years across the Pacific Northwest, significant load growth and changing system dynamics are creating risks for maintaining power system adequacy. This regional adequacy assessment for 2029 provides early warnings on system adequacy, with specific focus on how the Council's 2021 Power Plan resource strategy supports adequacy given the rapid changes the grid is experiencing, such as announced coal-to-gas conversions and transmission expansion in the region. This adequacy assessment finds that implementing the resource strategy in the plan – specifically achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system. Areas of risk remain, however. The same strategy, but only pursuing the low end of the Council's energy efficiency target, would not provide for an adequate system. Further, if data center load growth accelerates and more closely aligns with utility projections in the region by 2029, the resource strategy will also be insufficient to maintain adequacy. These risk areas, and other changing system dynamics, highlight the importance of the Council's upcoming power plan to provide new guidance to the region in support of an adequate, efficient, economical, and reliable power supply. In the meantime, the Council is continuing to track resource development, load growth trajectories, and other factors to provide timely updates through its Mid-Term Assessment of the 2021 Power Plan.

The Council uses an adequacy model called GENESYS to simulate the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis).

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Rather, the Council evaluates shortfalls as a signal for emergency measure needs. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events, and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

The adequacy assessment for 2029 explores how the Council's 2021 Power Plan resource strategy supports an adequate system. The assessment accounts for system changes that will be implemented by 2029, including load growth, in-region resource developments, and out-of-region market fundamentals. Electric load is expected to substantially increase by 2029, due to data centers and electric vehicles. However, announced changes to thermal plant retirements, such as Valmy 1 & 2 and Jim Bridger 1 & 2 conversions from coal to gas fueling, and anticipated transmission expansion throughout the WECC, including Boardman-to-Hemingway in the region, appear to alleviate some of the challenges associated with the increased loads when coupled with the 2021 Plan's resource strategy.

The 2021 Power Plan's resource strategy recommends that between 750 and 1,000 average megawatts of cost-effective energy efficiency, at least 3,500 megawatts of renewable resources, 720 megawatts of low-cost and frequently deployable demand response be acquired, as well as increasing balancing up reserve requirements to 6,000 megawatts to respond to growing short-term uncertainty in variable energy resources (primarily wind and solar) by 2027. Because the resource strategy provides a range for both energy efficiency and renewable development, the Council created a "reference strategy" to test in this assessment. This reference represents the high-end of the Council's cost-effective energy efficiency target (roughly equivalent to 1,300 average megawatts by 2029) and a renewable build consistent with many of the sensitivities analyzed in the plan that informed the strategy (roughly 6,600 megawatts by 2029).

The 2029 adequacy assessment tested a range of potential future conditions, including (1) the reference resource strategy (2) higher data center load growth, and (3) alternative trajectory within the resource strategy – the low end of the energy efficiency target.

The Reference scenario did not violate thresholds in any metric– frequency, duration, and magnitude – and therefore is deemed adequate. The Higher Data Center scenario used all the same assumptions from the reference case, except it added 1,600 average megawatts of additional power demand from the tech sector by 2029. The reference case anticipates roughly 2,400 of incremental tech-related aMW by 2029; the high data center scenario assumes 4,000 aMW. This scenario violated thresholds for all the metrics, and therefore is deemed inadequate. The Alternative Trajectory – Low End EE scenario used the same assumptions as the Reference case, but only met the low end of the efficiency target –

1,000 aMW instead of 1,300 aMW in 2029. This scenario satisfied some metrics (duration and energy), but it violated other metric thresholds (frequency and peak) and therefore is deemed inadequate.

The Reference scenario indicates that the 2021 Plan's resource strategy mostly eliminates summer challenges and greatly mitigates winter challenges – with only a minor set of system conditions that pose adequacy concerns in January evening ramp that are within the acceptable adequacy limits. However, should only the low end of cost-effective energy efficiency target be achieved, the region may experience winter challenges throughout majority hours of the day, with the greatest need in the morning and evening ramps, as well additional challenges in spring and summer. The Higher Data Center scenario further exacerbates the winter, spring and summer challenges as the resource strategy is insufficient to meet the potentially much higher electrification loads.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

Multi-Metric Adequacy Framework

The Council's multi-metric approach is philosophically different from relying on Loss of Load Probability (LOLP). In the past, adequacy was determined by whether a portfolio/strategy is expected to have no more than 1-in-20 years with at least one shortfall (LOLP of 5%). Instead, the new approach focuses on defining adequacy by whether a portfolio offers the protection against specific shortfall risks that the region wants to avoid.

To define the specific risks – and the metrics and thresholds associated with them - Council staff engaged closely with the Resource Adequacy Advisory Committee (RAAC) and regional partners to evaluate (1) aggregate regional emergency capabilities, and (2) what level of risk is the aggregate emergency capabilities of the region able to protect?

This is a key shift, where the emphasis of adequacy is placed on the significance of interpreting modeled shortfalls from GENESYS – the Council's adequacy model – as a signal for necessary emergency measures to be used to mitigate an actual curtailment.

GENESYS simulates the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis). Council staff have distinguished the emergency measures available to the region as Type I and Type II:

1. Type I refers to measures that are typically within a utility's control, such as relying on costly resources outside of the active portfolio, industry back-up generators, load buy-back provisions, and larger and costlier market purchases above market reliance limits.
2. Type II refers to extraordinary measures of extreme cases where customers may experience direct impacts, such as official's call to conservation, emergency load reduction protocols (rolling brownouts), or curtailing fish and wildlife operations.

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events – and thus the necessary emergency measures - and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

Philosophically speaking, by bridging modeled shortfalls to the need of emergency measures, the Council's multi-metric adequacy framework is aimed at protecting against the risk of Type II emergency measures. As such, quantifying the region's aggregate Type I emergency measures, and setting the metric thresholds to those capabilities, enables a probabilistic approach to how often extreme measures (Type II) are expected. This approach can be summed up as "Let's make sure any emergency measures aren't used too often (satisfying LOLEV)." And, "For the vast majority of the time let's make sure the emergency measures we rely on are not used too long or are too big (satisfying duration, peak and energy VaR)". As will be seen later this section, the significance of the VaR metric at the 97.5th percentile with a threshold associated with type I emergency measures means we can expect to entirely avoid the extreme, less desirable, emergency measures (Type 2) 39 out of 40 years.

However, because it is difficult to fully and accurately account for the magnitude and duration of all emergency measures, staff recognize that thresholds are approximations. Further, there is no clear line in the sand between magnitude of Type I and Type II measures as these may vary by utility and circumstance. As such, the framework should be understood as an evolutionary process towards redefining tail-end system risk than a complete characterization of Type I and Type II measures.

The Council's process to evaluate the metrics and threshold took several years, with 2022 dedicated to developing a provisional framework. The first use of the provisional multi-metric framework culminated in the 2027 Adequacy Assessment, including provisional threshold ranges for each metric to capture both lower and higher risk tolerances. In January of 2023, the Council decided to adopt the new multi-metric framework – and recognizing it will be an ongoing, evolutionary process – tasked staff to collaborate with the region on finetuning the thresholds.

Over the course of 2023, staff engaged with utilities, regional organizations, and public utility commissions to solicit feedback on the multiple metrics, thresholds, and approximation of emergency measures. Interim findings of the stakeholder engagement process were presented at the May 2023 Council meeting and the final findings in January 2024 with the RAAC Steering Committee and Technical Committee.

One important topic that was often raised is the relationship of the Council's adequacy work with the Western Resource Adequacy Program (WRAP) managed by the Western Power Pool. The roles of the Council and WRAP are complementary: the Council develops a long term, 20-year power plan, with recommendations for a six-year resource strategy for the region to ensure adequacy, while the WRAP focuses on near-team planning to ensure resource adequacy. As often discussed in the RAAC, the success or failure of the WRAP is a concern on stakeholders' minds for maintaining regional adequacy, and staff continue to engage closely with the WPP for long-term collaboration.

The outcome of the process is summarized in Figure 1, which maps the change from provisional thresholds to an interim recommendation that was used in this 2029 adequacy assessment. Modifications included (1) aligning LOLEV with the WRAP's seasonal use of Loss of Load Expectation (LOLE), but still report annual LOLEV, and (2) alongside Peak VaR and Energy VaR also report the Normalized VaR (NVaR) – as non-binding metrics - to provide comparative perspectives with utilities that report some normalized metrics.

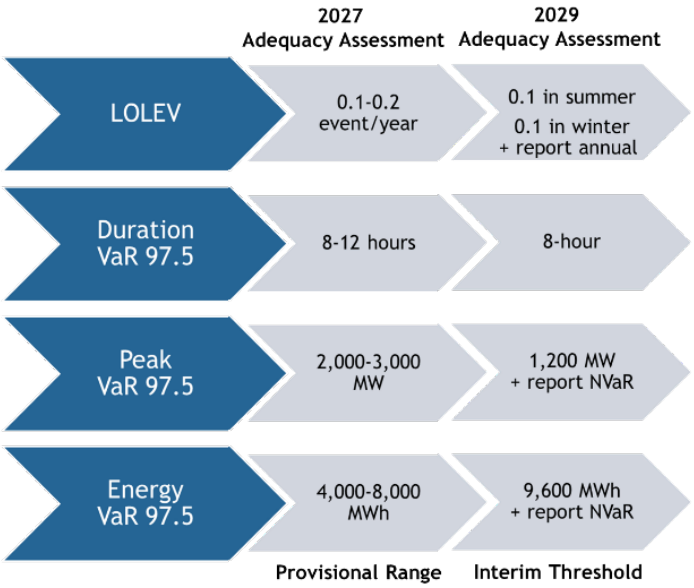


Figure 1. Evolution of metric thresholds

The following sections describe the metrics with greater details. For full descriptions and metric summaries, please see past RAAC presentations.

Loss of Load Events (LOLEV) to protect against frequent use of emergency measures

As the frequency of shortfalls is equivalent to the frequency of using emergency measures, a limit can be set for the frequency of simulated shortfalls as it relates to preventing overly frequent use of emergency measures.

The metric chosen to achieve this objective is the Loss of Load Events (LOLEV), which is the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Because periods of most concern include summer and winter staff heard feedback to align with the WRAP seasonal approach, and decided set a threshold value for both summer and winter at 0.1. However, system risk may change over time, so considering shortfall risk in spring and fall is deemed important as well. Therefore, the Council's adequacy studies also report an annual LOLEV (threshold of 0.1) to cover risk throughout the course a year.

Duration VaR to protect against tail-end (extreme) duration use of emergency measures

Long shortfall events can indicate insufficient system energy (fuel). However, as described earlier, a simulated shortfall event is not the same as a curtailment event, although it could turn into one if emergency measures are not enough to offset the peak and energy shortfalls of the event. Therefore, setting a limit for shortfall event duration is a critical part of maintaining an adequate supply.

Furthermore, long shortfall events can indicate insufficient system resiliency, where resiliency is defined as the ability of a power system to protect against – and quickly recover from – high impact, low-frequency events. Such events can occur in extreme weather (heat waves or cold snaps); significant loss of transmission (wildfires, ice storms, heavy winds) or loss of a major fuel supply (gas pipeline rupture). The metric chosen to achieve this objective is the Value at Risk (VaR) for shortfall event duration at the 97.5th percentile over all simulation years.

To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (and noted as zero if there is no shortfall). The Duration VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (no more than once per 10 years), it represents the risk of a real curtailment and not just a shortfall. The limit for this metric is set to 8 hours, to reflect the minimum shortfall duration that could lead to severe customer risk. Conditions that might trigger a long duration shortfall include extreme weather events, wildfires, and high winds – any event that disrupts major transmission lines or fuel supplies.

Peak VaR to protect against tail-end (extreme) magnitude of emergency measures

The Pacific Northwest's power supply has historically been capacity long but energy short. The region has had an excess of peaking capacity (machine capability) but continues to be limited by the water supply that powers the hydroelectric system, which provides more than half of the grid's nameplate capacity.

While the hydroelectric system's nameplate capacity is about 35,000 megawatts, it generates about 16,000 average megawatts per year, on average, and only about 12,000 average megawatts during a low water year. However, due to significant increases in variable energy resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand. Thus, it is important to include a metric to protect against excessively high-capacity shortfalls.

The metric chosen to achieve this objective is the Value at Risk (VaR) for capacity shortfall at the 97.5th percentile over all simulation years. To calculate this metric, the highest single-hour shortfall for each simulation year is recorded (or noted as zero if there is no shortfall). The Peak VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an extreme high-capacity shortfall to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (once or twice per 10 years), it represents the risk of exceeding type I emergency measure capability (implying that the more extreme, type II measures, could be needed), whereas the LOLEV frequency represents the risk of using emergency measures too often. The limit for this metric represents the amount of single hour demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency peaking capability. The risk of real curtailment is high when the Peak VaR97.5 exceeds this limit because avoiding a loss of service depends on the availability of extraordinary emergency measures not accounted for in the adequacy limit. The interim limit for this metric is set at 1,200 megawatts. The non-binding reported Peak NVaR 97.5 threshold is 3% (1,200 MW is approximately 3% of average peak load the region).

Energy VaR to protect against tail-end (extreme) annual aggregate use of emergency measures

The region's power supply continues to be energy limited because hydroelectric resources make up the lion's share of the supply. It is important to include a metric to protect against extreme annual energy shortfalls. But unlike the capacity metric, whose limit is tied to the highest single-hour shortfall, the energy metric must be tied to the entire year's unserved energy. This is because energy shortfalls are often equated to a lack of fuel, whereas capacity shortfalls are often equated to a lack of machine capability. Once the machine capability is sufficient to offset the highest capacity shortfall, all other capacity shortfalls can also be offset. However, simply having sufficient fuel to offset the highest energy shortfall does not guarantee that other energy shortfalls throughout the year can also be offset.

The metric chosen to achieve this objective is the VaR for energy shortfall at the 97.5th percentile over all simulation years. To calculate this metric, total annual unserved demand for each simulation year is recorded (or zero if there is no shortfall). The Energy VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively high annual energy shortfall to no more than once per 40 years. Similar to Peak VaR, this frequency is much smaller than that chosen for the LOLEV, representing the risk of exceeding type I emergency measure capability.

The limit for this metric represents the amount of annual energy demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency energy generating capability. The risk of real curtailment is higher when the Energy VaR97.5 exceeds this limit because avoiding a loss of service would depend on the availability of emergency measures not accounted for in setting the adequacy limit.

Because it is difficult to accurately assess the amount of available emergency energy, alternative approaches can be used to set the VaR97.5 limit. By considering the "worst acceptable" annual unserved energy as the longest allowed 97.5th duration of 8 hours, where each hour has the largest allowed 97.5th hourly peak magnitude of 1,200 MW, the limit can be set at 9,600 MWh for the year. The non-binding reported Energy NVaR 97.5 threshold is 0.0052% (9,600 MWh is approximately 0.0052% of average annual energy in the region).

Updates to load growth in 2029 since 2027 Assessment

The region is anticipating rapid load growth, driven by forecasted data center growth and transportation electrification. However, there is uncertainty regarding how much load will materialize from both sectors. This load uncertainty poses a risk for adequacy, as the region may need to respond to a rapid increase in load as data centers and electric vehicles arrive. To help account for load uncertainty, two data center load growth trajectories are tested. The load forecast for the 2029 resource adequacy assessment is projecting higher loads than the 2021 Power Plan Long Term Forecast for 2029. The higher 2029 forecast is attributable to:

1. Forecast Timing – the Resource Adequacy Assessment Forecast for 2029 has three additional years of recent load, weather and economic history to work with
2. Much of the growth in load projections is explained by updated information about forecasts for data centers, chip fabrications, and electric vehicles

3. Additional growth projected beyond these two drivers – such as changes to population growth following historical trends, or some facets of efficiency that is being missed

Data centers and chip fabrication loads

Data center and chip fabrication loads (tech loads) are projected to be a driver of load growth in the Northwest. There is substantial uncertainty regarding how much load they will bring to the region. Figure 2, below, provides a range of incremental tech load forecasts in gray. By 2029, the range spans from a floor of 1,800 aMW of new load, to a ceiling of 6,500 aMW. All of these loads are assumed to be flat across the year.

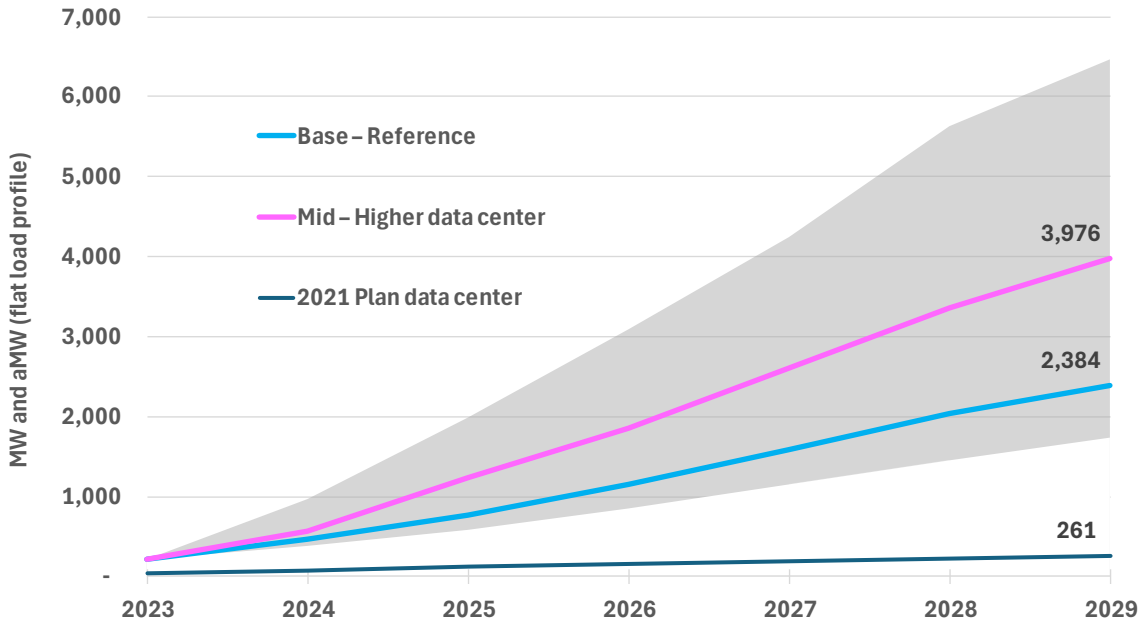


Figure 2. Incremental data center and fab growth forecast, 2023 to 2029

For this adequacy assessment two tech load forecasts are used to capture the load uncertainty. The base forecast, shown in light blue, assumes recent development trends will continue and incorporates recently announced projects. It adds around 2,400 aMW of new load to the Northwest by 2029. The mid case, in pink, assumes an acceleration in tech project development and is closer to what the region's utilities are projecting. It adds nearly 4,000 aMW of new load to the region by 2029. The description of the full scenarios tested is provided in the "Scenario Description" section (page 23).

Electric vehicles

Unlike data center load in the 2021 Power Plan, transportation electrification load was already gaining traction with earlier forecasts showing increased demand from electric vehicles (EV) in the region. In efforts to enhance the EV forecast for the 2029 adequacy assessment, Council staff evaluated several EV forecasting models and datasets to forecast (1) annual vehicle fleet and demand by state and balancing authority (BA) of light duty vehicles (LDV), medium duty vehicles (MDV), and buses, and (2) hourly charging profiles. To derive BA level data, BA allocation factors were calculated using estimates of vehicle registration locations, and when available, compared against utility IRP forecasts. The models and datasets included PNNL's GODEEP dataset for EV forecast by BA, Energy Policy Simulator (EPS, state level) by Energy Innovations and Rocky Mountain Institute, and California Energy Commission (CEC) charging forecasts. Forecasts were compared to actuals (2020-early 2024) and the 2021 Power Plan High Electrification scenario – which included high penetration of EVs – for comparison.

Table 1 provides the summary of transportation electrification data assumptions. Because actuals for Washington and Oregon (especially LDV, the bulk of the fleet) resembled EPS and 2021 Power Plan High Electrification, staff determined that using the existing High Electrification forecasts for LDV was appropriate. However, for MDV and buses, EPS results were utilized but scaled to 2021 Power Plan using LDV factors. Charging profiles for LDV, MDV and buses all assumed to be influenced by time-of-use (TOU) rates, derived from CEC profiles. TOU rates can have substantial impact on charging behavior, mainly lowering the peak demand in late afternoons and evenings by spreading the charge over periods of less demand and costly electricity either during the night or midday. Staff assumes that by 2029 utilities will adopt TOU for EVs as a cost-effective response to handling EV load growth, and will continue monitoring policies and EV sales across the four states as on-going work towards future forecasts.

Table 1. Summary of transportation electrification data assumptions

Vehicle Type	Fleet Method	Demand Method	Charging Profile
Light Duty Vehicle (BEV and PHEV)	2021 Power Plan High Electric Forecast	Demand by state for light duty passenger cars and trucks - from the 2021 Power Plan High Electric Forecast	California Energy Commission time-of-use LDV profiles
Medium Duty Vehicle (BEV Light & Medium Freight)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors.	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use MHDV profiles
Bus (BEV Public transit and school)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use bus profiles

The result of the hybrid approach to the regional EV forecast, provided in Figure 3, show that that expected EV load by 2029 is 1,147 average megawatts (and ~5,000 aMW in 2045, not shown in graph). Light duty vehicles account for 87% of the share, with MDV and buses starting to pick up after 2025. The majority of forecasted EV load is in Washington (65%) and Oregon (30%). In terms of electric fleet size, the region is expected to have over 1.82 million LDVs, over 51,000 MDVs, and over 7,000 buses by 2029.

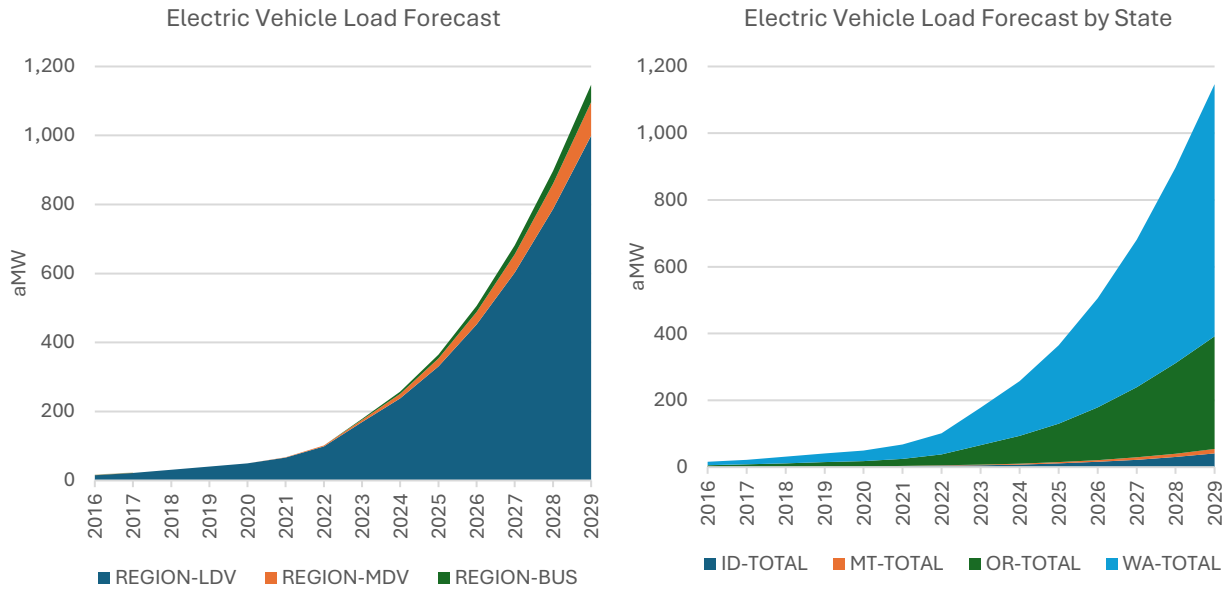


Figure 3. Electric vehicle load forecast by region and state

Other system changes since 2027 Assessment

Alongside expected yet uncertain load growth, there are additional changes to the regional power system that are important to consider since the 2027 assessment, including (1) announced thermal retirement changes of coal-to-gas conversion, (2) expanded transmission capacity, and (3) hydro changes from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects.

Thermal coal-to-gas conversions

The interaction of decarbonization policies, adequacy concerns with extreme weather events, and the economics of thermal plants paved the way for changes to announced decommissioning of several coal plants in the region. But instead of maintaining operations as usual, coal plants can be converted to gas, a process known as “coal-to-gas conversions.”

Major coal plants in the region that were originally planned for decommissioning have now shifted to coal-to-gas, seen in Table 2 and Figure 4. This amounts to a substantial resource addition since the 2027 adequacy assessment totaling. These plants include Jim Bridger 1 and 2 (~1,200 MW) and North Valmy 1 and 2 (~280 MW) for a total of ~1,480 MW of thermal plants, which could have direct adequacy benefits to the region that is expecting substantial load increase of 3,400-5,000 aMW.

Table 2. Announced coal decommissioning and coal-to-gas conversions

Coal Unit	Nameplate Capacity (MW)	Planned Retirement (Feb 2024)	Planned Retirement (2021 Plan)
Colstrip 1	358	2020	2020
Colstrip 2	358	2020	2020
Boardman	601	2020	2020
Centralia 1	730	2020	2020
Jim Bridger 1	608	2024*	2023
Jim Bridger 2	617	2024*	2028
Centralia 2	730	2025	2025
North Valmy 1	277	2025[x]	2021
North Valmy 2	289	2025[x]	2025
Colstrip 3	778	–	–
Colstrip 4	778	–	–
Jim Bridger 3	608	2030*	–
Jim Bridger 4	608	2030*	–

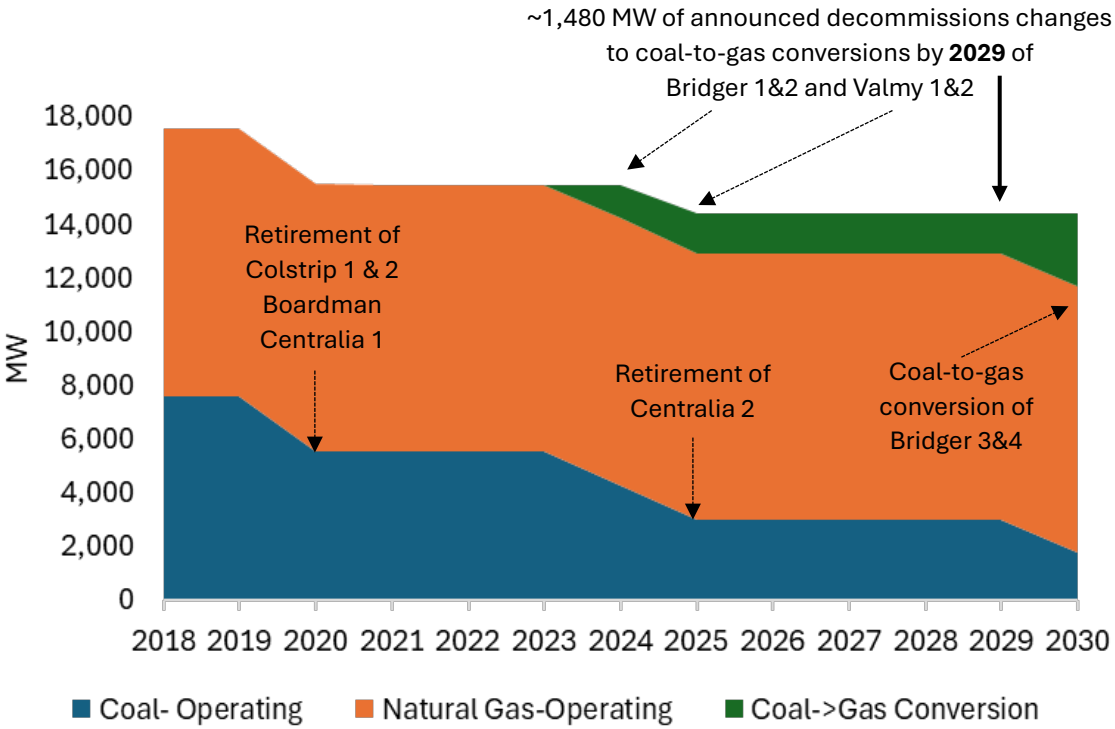


Figure 4. Cumulative thermal capacity changes in the region

Expanded transmission capability

Several major transmission expansion projects are slated to begin throughout the WECC in the coming years, including Boardman-to-Hemingway (B2H) in the PNW region. For the 2029 assessment, staff included projects that have already been announced as close to completion, started construction, or with high likelihood of being completed by 2029. Table 3 and Figure 5 below detail the new transmission expansion lines and their modeling topology. In total, 12,700 MW of transmission capacity will be added throughout the WECC, with B2H providing 1,000 of additional east-west capacity in the region between Idaho Power and BPA.

Table 3. Transmission expansions in 2029 Assessment

Planned Transmission	New Capacity (MW)	Path	Online Date	GENESYS Buses	Existing Today (MW)	New 2029 capacity (MW)
Ten West Link	3,200	SCE to APS	2024	So_Cal to Arizona	1,400	4,600
SunZia	3,000	PNM to APS	2026	New Mexico to Arizona	1,700	4,700
Transwest Express	3,000	WAPA Wyoming to PACE UT	2027	wapa RM to PAC_UT	650	3,650
Transwest Express	1,500	PACE UT to Nev South	2027	PAC_Ut to Nevada South	250	1,750
SWIP North	1,000	IP to North Nevada	2027	IP to north Nevada	350 | 185	1,350|1,185
B2H	1,000	IP to BPA_OR	2026	IP to BPA_OR	2,000	3,000

The expanded transmission capability in the region could have adequacy benefits by alleviating transmission congestion across the Cascades and enabling greater flow across the region. This is especially beneficial as more wind resources are built in Montana and Wyoming to serve load west of the Cascades.

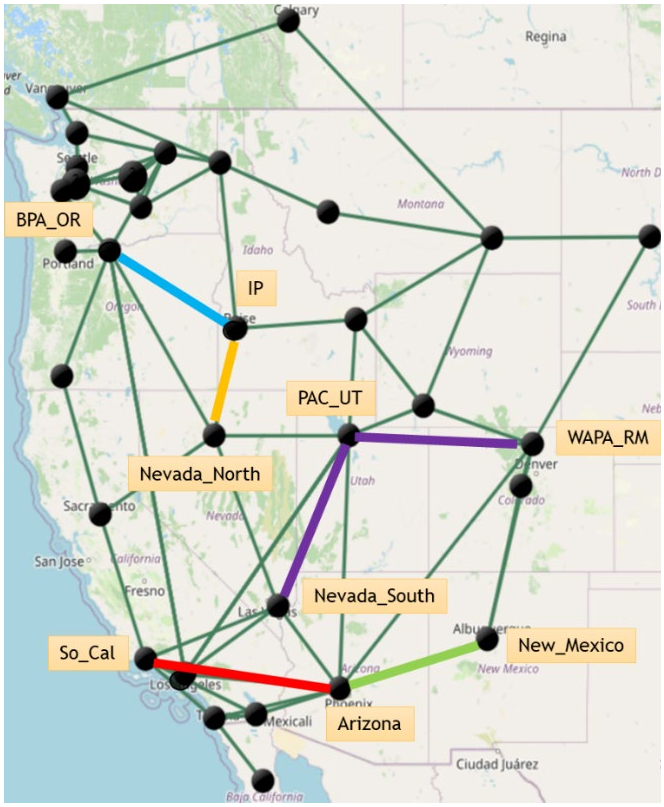


Figure 5. Transmission expansions in 2029 Assessment

However, the other transmission projects, while beneficial for the region, do not necessarily have the same adequacy benefit to the region as B2H. This is the case because of the market reliance limit for adequacy used by the Council. Though the new capacity would help WECC-wide market dynamics, including the export and import capability of SWIP North through Idaho Power, the overall import limit (set for adequacy) is well below the existing (current, pre-capacity expansion) capability of the transmission lines between the region and WECC.

In other words, the Council's winter market reliance of 2,500 MW and a summer reliance limit of 1,250 MW are the limiting factor for import capability from outside of the region. This limit was set to hedge against the risk of relying on the market at times of need and differs seasonally due to the fact the PNW peaks in winter and the WECC in summer. The market reliance limit, and market fundamentals in general, are routinely discussed in the Resource Adequacy Advisory Committee and the System Analysis Advisory Committee, and in the meantime the limit is the preferred path. Future considerations could change the decision, which will be discussed in future advisory committees and Council meetings.

RCBA Appendix B: Changes to Lower Snake and Lower Columbia

For power planning and resource adequacy assessments, the Council's Power Division staff aims to model the existing system to the best of their capabilities. An important piece of this work is to model the hydro operations consistent with any requirements for river operations. To that end, staff recently made updates to the Council's GENESYS model to

reflect changes to hydro operations resulting from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects. Issued in December 2023, the changes are geared to increase spill for improved juvenile fish survival in the Lower Snake and Lower Columbia.

The impact of increased spill is reduced spring and early summer hydro generation. There is minor hydro generation reduction in the fall and winter, varying by project. However, an increase in hydro generation is expected in August. In addition to monthly changes in average hydro generation, minor changes in daily hydro generation flexibility are also expected.

From an adequacy perspective, while hydropower is slightly reduced, based on the limited subset of studies used for a comparative study, the changes do not lead to a significantly different regional adequacy result. Offsetting the reduced hydropower is a small increase in regional thermal generation and market reliance, yet within the market reliance limit, throughout most of the year, especially at night.

Since completion of the analysis for the 2029 adequacy assessment, an Agreement in Principle on the changes of the Columbia River Treaty has been made by the US and Canadian governments. The Council will continue to evaluate the impact on power system planning and resource adequacy in future analyses.

Scenario description

As an adequacy assessment, the main goal is to test the resource strategy outlined in the Power Plan given potential risk scenarios to signal to the region about adequacy and areas of concern. As a reminder, the resource strategy, provided in Figure 6, of the 2021 Power Plan to achieve by 2027[1] includes (1) at least 3,500 MW of renewable resources, (2) 750-1,000 aMW of energy efficiency, (3) 720 MW of demand response, and (4) doubling the balancing up reserves to hold 6,000 MW to support integration of renewables.

2029 Resource Strategy – the reference

In this assessment, looking 2 years past 2027, the resource strategy in 2029 continues the trajectory of resource assumptions used in 2027 reference case, seen here:

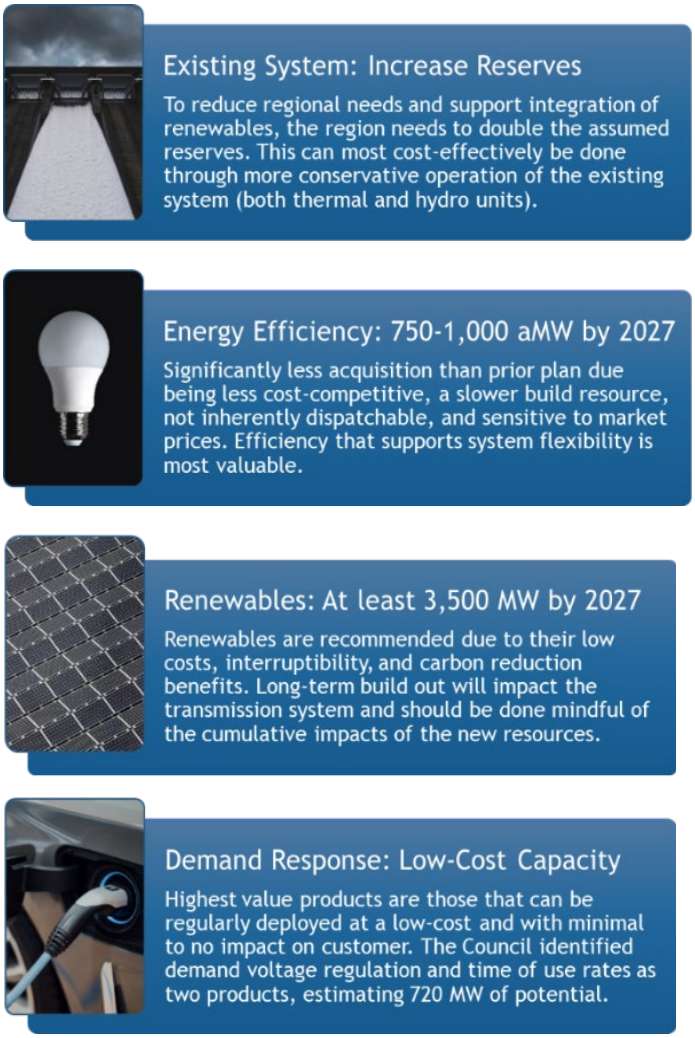


Figure 6. 2021 Power Plan resource strategy

Table 4. Comparison of 2029 and 2027 reference strategy

Portfolio	2029 Adequacy Assessment	2027 Adequacy Assessment
Renewables	6,600 MW	5,900 MW
EE	1,300 aMW	1,000 aMW
DR	720 MW	720 MW
Reserves	6,000 MW	6,000 MW

[1] See pages 46-48 in the 2021 Power Plan Section 6: Resource Development Plan as well as page 107 in the 2021 Power Plan Section 9: Cost Effective Methodology for Providing Reserves

The 700 MW increase in renewables is consistent with several buildouts observed in the 2021 Power Plan and the higher range of renewables tested in 2027, seen in Figure 7. The additional 300 aMW of energy efficiency is consistent with the assumption of reaching the high end of the cost-effective energy efficiency target.

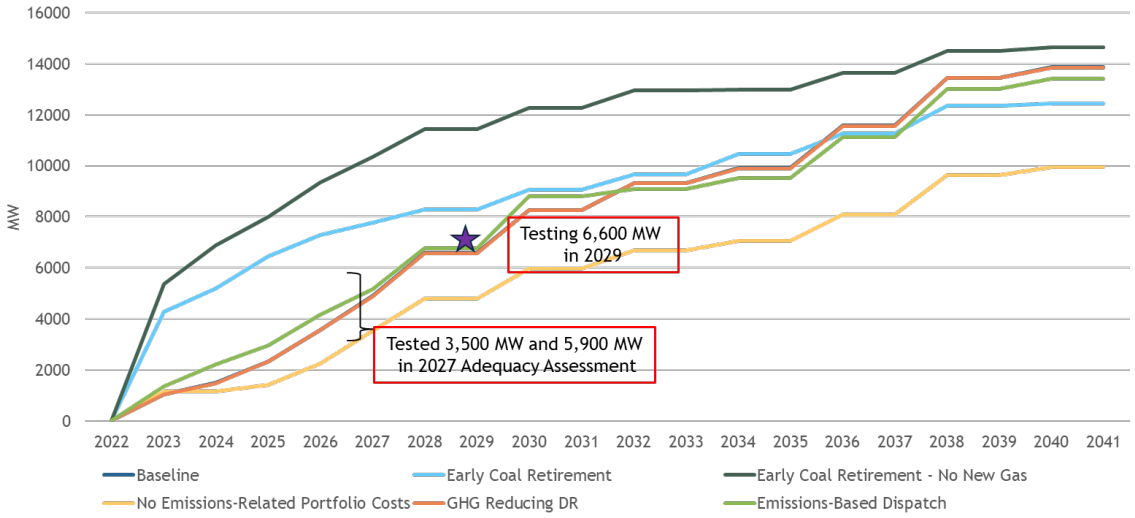


Figure 7. Example of renewable buildout trajectories from the 2021 Power Plan Resource Strategy

The scenarios

Staff engaged with the RAAC and SAAC to define the risks and setup to test for the assessment, resulting in the following list of potential scenarios:

1. Reference
2. Higher data center load (in region)
3. Alternative Trajectories within Resource Strategies (low end of energy efficiency target)
4. In-region gas supply limitations
5. Earlier availability of transmission (reconductoring in region)
6. Delayed availability of transmission and emerging tech in WECC
7. Emission pricing

While all scenarios provide important adequacy insights to the region, given budget constraints and proximity to preparation for the next Power Plan, staff had to prioritize three key scenarios for the assessment (in green), including a reference case, a higher data center load case, and an alternative to the resource strategy case that only achieves the low end of the cost-effective energy efficiency target. The other scenarios (in red) include financial risks that would be considered in upcoming wholesale market forecast, and broader system risks (adequacy and resource strategy) in the next Power Plan. Thus, the

tested scenarios differ in terms of energy efficiency savings and Data Center Loads, but share the same EV loads. Seen in Table 5, the Higher Data Center scenario tests the same resource strategy as the Reference against ~1,600 aMW of additional load. The Low End EE scenario tests the same data center load as the Reference, but with 300 aMW less of EE.

Table 5. Load difference across 2029 adequacy assessment scenarios

Scenarios	EE Savings (aMW)	EV Loads (aMW)	Data Center Loads (aMW)
2029 Reference	1,300	1,048*	2,386
2029 Low End EE	1,000	1,048*	2,386
2029 Higher Data Center	1,300	1,048*	3,976

* Value for 2029 incorporates the 1,147 aMW (Section 4) but subtracts the embedded EV load in the base forecast in 2022. Hence, there is an additional 1,048 aMW to reach the 1,148 aMW by 2029.

The expected annual load, and average peak load by season for each of the scenarios is provided in Table 6 from simulation results.

Table 6. Average simulated loads from 2029 adequacy assessment scenarios

Scenario	Average Annual Load (aMW)	Oct-Mar Avg Peak (MW)	Apr-Sep Avg Peak (MW)
Reference	25,271	36,724	34,034
Low End EE	25,495	36,947	34,291
Higher Data Center	26,861	38,314	35,624

The Council uses three separate climate change scenarios, with each possessing 10 unique sets of climate-dependent hydro-load combinations, and six wind generation profiles that total in 180 simulations per study (10 hydro-load combinations x six wind profiles x three climate scenarios). Generally, each of the climate scenarios represents a risky hydro-load profile: CanESM (scenario A) captures more risk of low summer hydro generation and higher summer loads, CCSM (scenario C) captures high winter hydro with early runoff lower summer hydro conditions. Lastly CNRM (G) captures risk of low winter generation with higher winter loads.

These simulated loads highlight the potential system risks that the resource strategy needs to address throughout the year. In fact, certain load conditions in scenario G surpass 41,000 MW at peak system needs even at the Reference scenario. The results section will explore the type and timing of shortfalls and lead way to understand the adequacy risk for the region.

2029 Assessment results

Despite the substantial load growth, this assessment finds that implementing the resource strategy in the 2021 Plan – achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system in 2029 as all adequacy metrics for the Reference scenario have been satisfied. Given the additional system changes, the region likely maintains adequacy due to the mitigating benefits of coal-to-gas conversions of Jim Bridger 1 & 2 and Valmy 1 & 2, as well as the added B2H transmission expansion (alleviating congestions and enabling greater east-west transfer in the region).

However, the region still faces adequacy risks, even with the additional system changes. Pursuing the same resources strategy as the Reference but only achieving the low end of the cost-effective energy efficiency target (1,000 aMW instead of 1,300 aMW in 2029) would not result in an adequate system. Seen under the Low End EE results, the scenario satisfied the duration and energy metrics, but violated the frequency (winter) and peak metrics and therefore is deemed inadequate.

Furthermore, should data center load growth accelerate and exceed current trends to match high-end trajectories of utility projections by 2029, the resource strategy will also be insufficient to maintain adequacy as the Higher Data Center scenario violated all adequacy metrics. A qualitative high level summary of the 2029 adequacy assessment is provided in Figure 8.

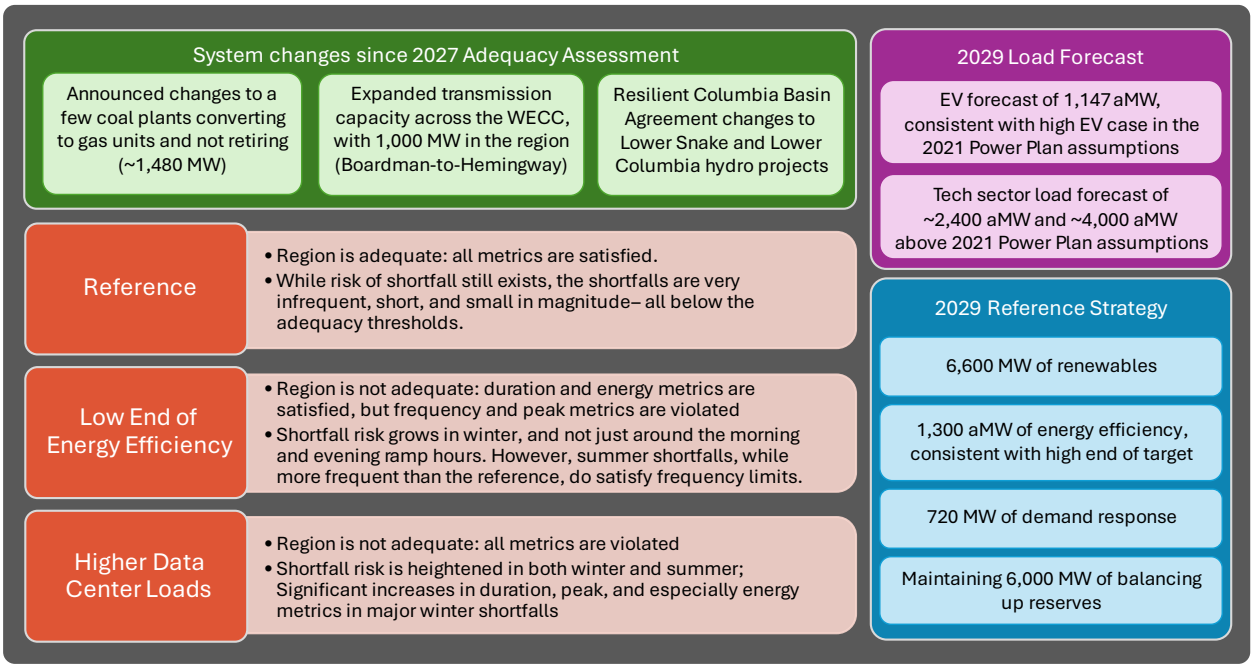


Figure 8. High-level summary of 2029 Adequacy Assessment

The results of the adequacy metrics across the scenarios are provided in Table 7. While a value of "0" might appear odd for the Duration and Peak and Energy VaRs, it does not mean there is no shortfall risk. Rather, it is a probabilistic representation signaling the shortfall risk in 39 out of 40 years is extremely low. As will be described in more detail later, the shortfall risk under the Reference scenario only start at the 98.8th percentile, and become substantial after the 99.5th percentile. In fact, out of 180 simulation years in the Reference scenario, only 4 experienced at least one shortfall (1-event year), with 9 shortfall events in total. Considering the summer and winter LOLEVs of 0.022 and 0.017, the implication is that the resource strategy, alongside with the changes to thermal coal-to-gas conversions and B2H, the region would expect one shortfall in the summer every 45 years, and one shortfall in winter every 58 years. Relating this to LOLP – solely for comparative perspectives as LOLP is not used - the Refence scenario results with an LOLP of 2.2%, well below the previous LOLP metric threshold of 5%.

Table 7. Adequacy metric results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MW	0	4,196	196,324

The risk is different with only achieving the low end of the energy efficiency target. From a frequency perspective, the number of winter events (winter LOLEV) exceeds the threshold (1-event in 2.85 years instead of not more than 1-event in 10 years), but summer is satisfied (1-event in 30 years). This highlights the benefits of achieving the high end of energy efficiency in protecting against winter events. Duration wise, the Low End EE does protect against long duration shortfalls, indicating that 39-out-of-40 years shortfalls will be at or below 1.5 hours long. Lastly, while Energy VaR is satisfied, with 39-out-of-40 years expecting the annual aggregate shortfall to be half of the energy threshold, Peak VaR is violated – by 367 MW. This situation is helpful in illustrating the importance of considering both the peak hourly shortfall and aggregate annual shortfall; in terms of emergency measures – there is enough emergency "fuel" in the system on an annual basis, but enough hours lack the emergency capacity to mitigate larger shortfalls. From the 180 simulation years, the Low End EE scenario had 14-event years (LOLP of 7.8%) with 80 shortfall events in total.

Under the Higher Data Center scenario - which the resource strategy and system changes do not mitigate the risk of increased loads - the metrics are violated to even a greater degree. Both winter and summer are well above the threshold, with winter especially vulnerable to frequent events, and the risk of long duration shortfalls surpass the limit by 2.65 times (21 hours at the 97.5 percentile). In terms of Peak VaR, the metric exceeds the threshold by 1,876 MW (at 3,076 MW), but the Energy VaR sheds light on the tail-end risk of aggregate annual fuel availability – the metric is 20 times the threshold at 196,324 MWh. This difference further highlights the need of different considerations of solutions for higher load futures. From the 180 simulation years, the Higher Data Center scenario had 24-event years (LOLP of 13.3%) with 296 shortfall events.

Aside from the above metrics used to determine adequacy, the three non-binding reported metric (Annual LOLEV, Peak NVaR and Energy NVaR) provide additional perspectives for comparative risk, seen in Table 8. The results echo the same outcome with the adequacy metrics – the Reference satisfies all non-binding metrics, the Low End violated annual frequency and Peak NVaR but satisfied Energy NVaR, and the Higher Data Center violated all metrics.

Table 8. Results of reported (non-binding) metrics

Type	Non-Binding Reported Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Annual LOLEV	0.1	0.05	0.444	1.644
Magnitude	Peak NVaR 97.5	~3%	0	4.2%	9%
Magnitude	Energy NVaR 97.5	~0.0052%	0	0.002%	0.09%

Shortfall statistics

As seen with the metrics, while both the Low End EE and Higher Data Center scenarios are inadequate, the risk they pose is not the same. Comparing some of the metric results helps explain this. To understand the adequacy risk of the three scenarios to the region, a closer examination of the shortfall statistics – and distributional characteristics – is warranted.

Frequency

From a frequency perspective, considering that the annual LOLEV is higher than the sum of summer and winter LOLEVs suggested that there are events also occurring in spring and fall. As such, staff explored the seasonal LOLEVs, presented in Table 9. One interesting find is the indication of events in the spring, including in the Reference case. While very low expected spring-event frequency (one in 91 years) in the Reference case, the Low End EE spring-event frequency is higher than the summer. Though spring events are still infrequent

(1-in-22 years), as is fall event frequency (1-in-59 years) it raises the awareness of monitoring shoulder seasons. This is especially important given maintenance timing that could coincide with challenging system conditions that could stress the system towards a shortfall.

Table 9. LOLEV across the seasons

LOLEV Period	Months	Threshold	Reference	Low End EE	Higher Data Center
Winter	Dec-Feb	0.1	0.022	0.350	1.294
Summer	Jun-Aug	0.1	0.017	0.033	0.300
Annual	All	0.1	0.050	0.444	1.644
Spring	Mar-May	0.1?	0.011	0.044	0.039
Fall	Sep-Nov	0.1?	0.000	0.017	0.011

VaR duration, peak and energy

The next several charts capture (1) the distribution of shortfall statistics (i.e. max duration shortfall, max peak shortfall, and annual energy shortfall from each of the 180 simulations per scenario), and (2) the actual distribution counting all events in each scenario. For the distribution of shortfall statistics, the total amount of observations (per metric) is 180. However, most of the simulation years had no shortfalls and therefore 0 will be recorded. For example, recall that the Reference scenario only had 4 event-years, so the shortfall statistic only records 4 non-zero duration, peak and energy values, and 176 zeros. Likewise, the Low End EE only records 14 non-zero values, and 166 zeros. Lastly, the Higher Data Center scenario has 24 non-zero values and 156 zeros.

Ranking the non-zero observations of each metric is an easy way to understand the percentile approach. The largest observation in each metric represents the 100th percentile, and the lowest non-zero observation is the percentile where shortfalls start occurring. Only non-zero observations are included in the graphs. Repeated non-zero values in the same study are also removed. It's also good to remember when examining the metric distributions that observations to the left of the VaR 97.5 vertical lines may be much larger than the threshold. By definition, the framework does not intend to protect against them. What matters is that the 97.5th percentile is at or below the threshold to satisfy a tail-end risk in 39-in-40 years.

A good example of this is featured in the max duration curves of the studies in Figure 9, especially the Low End EE scenario. The Duration VaR 97.5 value is 1.5 hours, satisfying the 8-hour threshold. However, the maximum shortfall durations in the study are 22, 21, 18, and 11 hours, followed by 2 and 1 hours. The risk of 22, 21 and 18-hour long duration shortfalls is substantially smaller than 1-in-40 years. However, in the Higher Data Center

scenario, the Duration VaR 97.5 value is 21 hours, a continued risk up to the 96th percentile, with much longer extreme shortfall durations (up to 120 hours). Under the Reference scenario, all duration metric values were below the threshold, including the maximum (100th percentile) of the study at 4 hours.

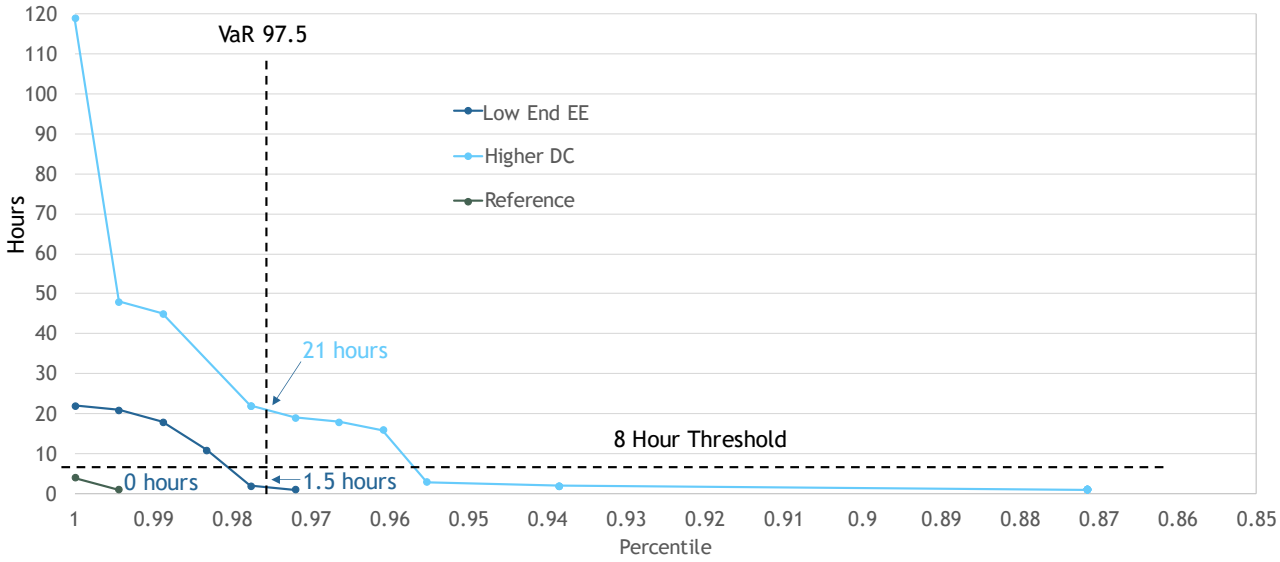


Figure 9. Max duration curves across the scenarios

Aside from the longest duration shortfalls calculated for the metric, considering the distribution of all shortfall durations (Figure 10) highlights that the majority of shortfalls, including in the Low End EE and Higher Data Center scenario, are short. In fact, around ~42% of all shortfalls in both studies are only 1 hour long, and ~70% less than 4 hours.

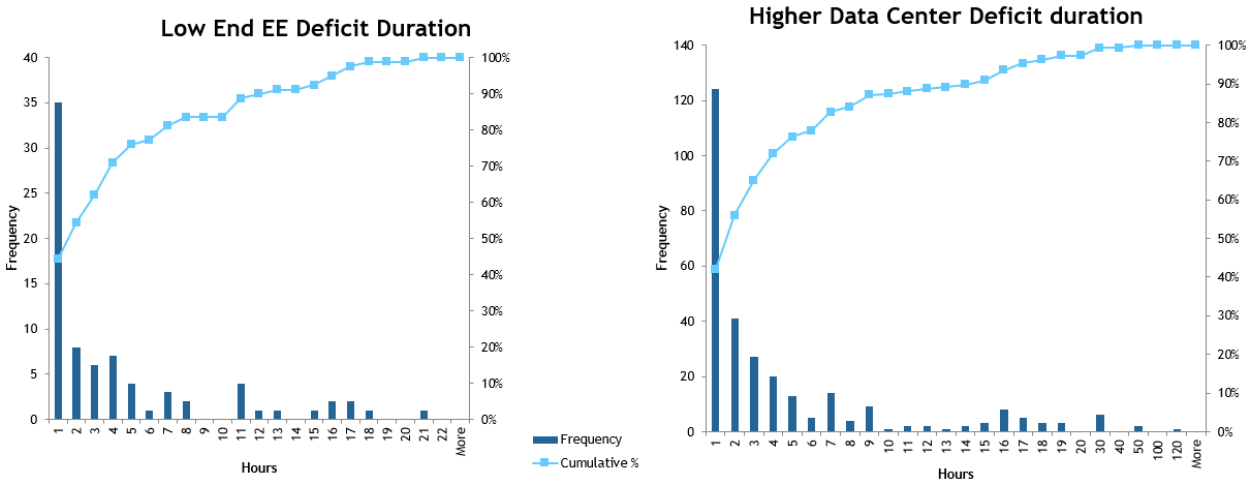


Figure 10. Distribution of shortfall durations in Low End EE and Higher Data Center scenarios

Maximum Peak distribution shows the tail-end magnitude of events, seen in Figure 11. All shortfall peaks in Reference scenario are below the threshold. However, the Low End EE is 367 MW shy of the threshold, and the Higher Data Center is 1,876 MW over. Theoretically, this implies the perfect capacity of needed resources to satisfy this metric, with the guiding principle that the additional resources would lower the curves by those magnitudes. However, this is mentioned as a nod for future analysis and not part of the adequacy assessment given the role is to provide an adequacy signal, not recommend a portfolio.

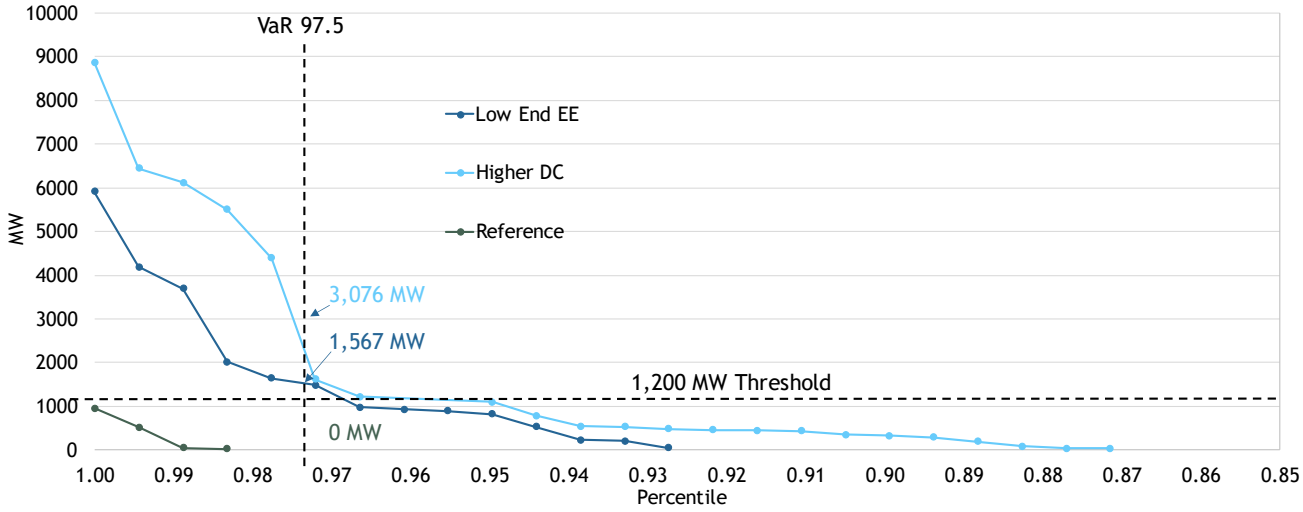


Figure 11. Max peak curves across the scenarios

There is greater diversity of shortfall peaks when considering the full distributions, observed in Figure 12. In both scenarios, around 20% of shortfall peaks are below 300 MW, just over 50% are below 900 MW, and ~68% of shortfalls peaks are below 1,200 MW.

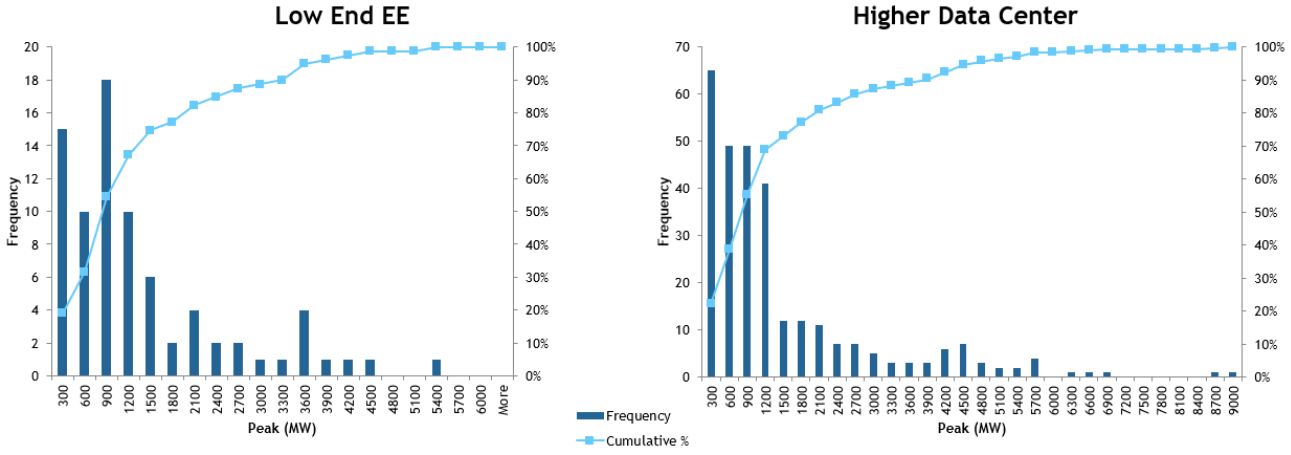


Figure 12. Distribution of shortfall peaks in Low End EE and Higher Data Center scenarios

Reconciling the perceived differences between the Peak VaR metric and curve and the actual peak shortfall distribution is that the fact that only a handful of simulation years (from 180) experienced shortfalls. For example, in the Low End EE scenario, 56 out of the 80 shortfall events are from just 3 simulation years. These specific years are associated with challenging low water conditions throughout the year; coupled with certain renewable wind conditions, this may pose adequacy risks. The same challenging simulation years belong to a broader group of six years. In the Higher Data Center scenario, they account for 220 of the 296 events, with another 52 events clustered in a different set of challenging hydro-load-wind conditions.

The annual Energy curves are provided in Figure 13. The Reference scenario's Energy observations are all below the threshold. And while the Low End EE scenario's Energy VaR is satisfied, there are extreme energy observations beyond the intention of risk protection. The Higher Data Center expands the risk of extreme energy shortfalls, crossing the threshold around the 94.5th percentile.

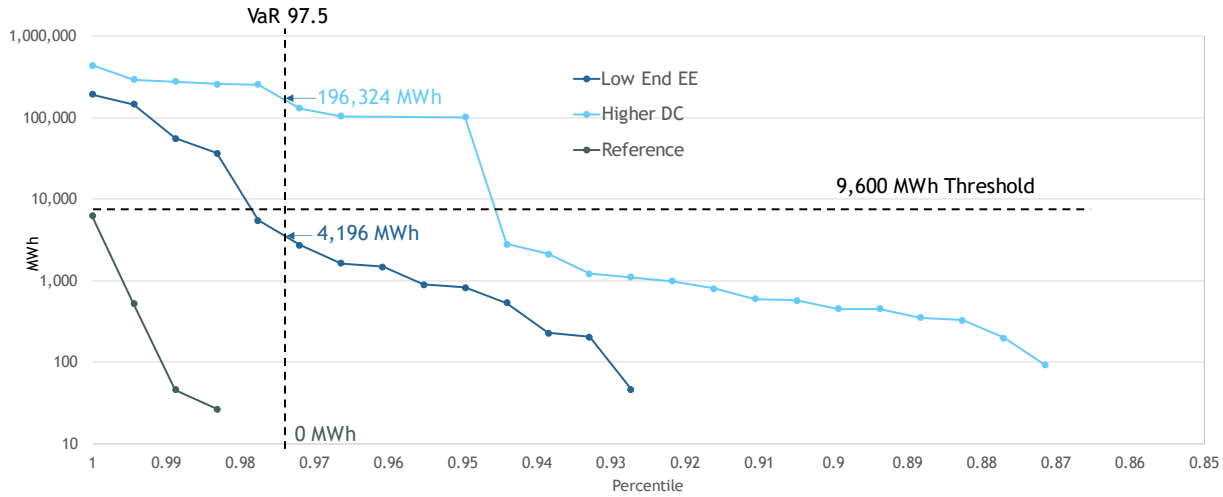


Figure 13. Annual energy curves across the scenarios

Timing of shortfalls

The final section of the results discussion focuses on timing of shortfalls, provided in Figures 14-16. While shortfall timing is not an adequacy metric, evaluating the potential hours of needs throughout each month sheds light on connections to other system stressors. Under the Reference scenario, the handful of shortfalls occurred mostly in winter, with the biggest single event in January during the evening ramp/early night period of 20:00-midnight, seen in the heatmap below; keeping in mind these are very infrequent, with winter LOLEV of 0.022, summer of 0.017 and spring of 0.011.

However, the Low End EE scenario has increased risk of challenges in several periods. The biggest peak shortfalls occur during winter morning and evening ramp hours. A handful of conditions could see shortfalls observed throughout all hours of those days as well. While these shortfalls are still infrequent – they occur more than allowed (winter LOLEV of 0.35, roughly 1 event in 2.85 years) – but are still important to understand. Unlike the reference, there is greater risk of evening/night shortfalls in the spring and summer as well as morning and day in spring (but within the allowed limits). The Higher Data Center scenario further exacerbates similar trends.

While the shoulder seasons – spring and fall - have historically had little adequacy risks, changing system conditions may alter this over time. The risk may still be tied to availability of hydro and earlier runoff coupled with increased loads, but these seasons warrant attention, nonetheless. First, increased loads (whether from higher tech loads or from achieving the low end of energy efficiency) may strain the system during these times in ways similar conditions posed little risk before. Second, because maintenance schedules for hydro and thermal plants are often during spring and fall, these may further coincide with conditions that could pose adequacy challenges. These reasons highlight the benefit of considering the LOLEV frequency metric across all seasons.

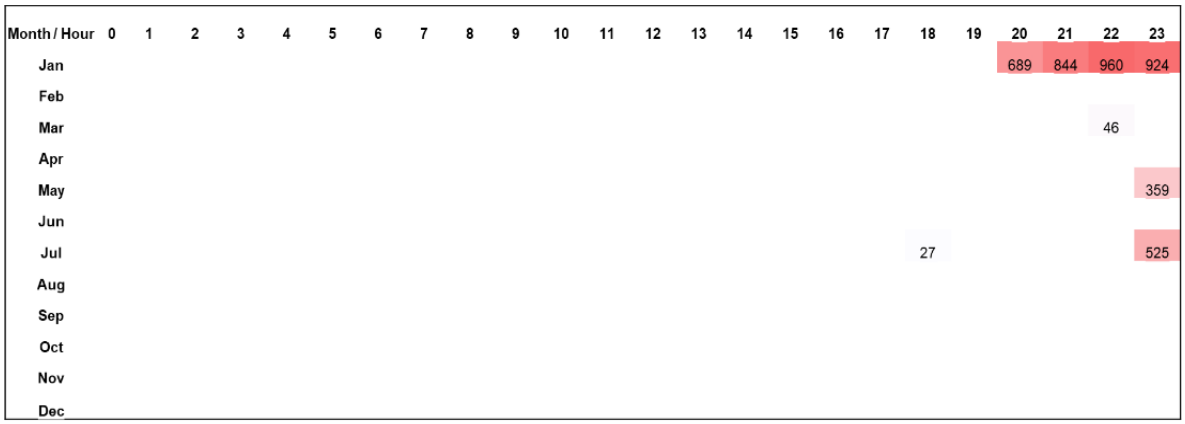


Figure 14. Reference scenario shortfall timing – peak magnitude (MW) heatmap

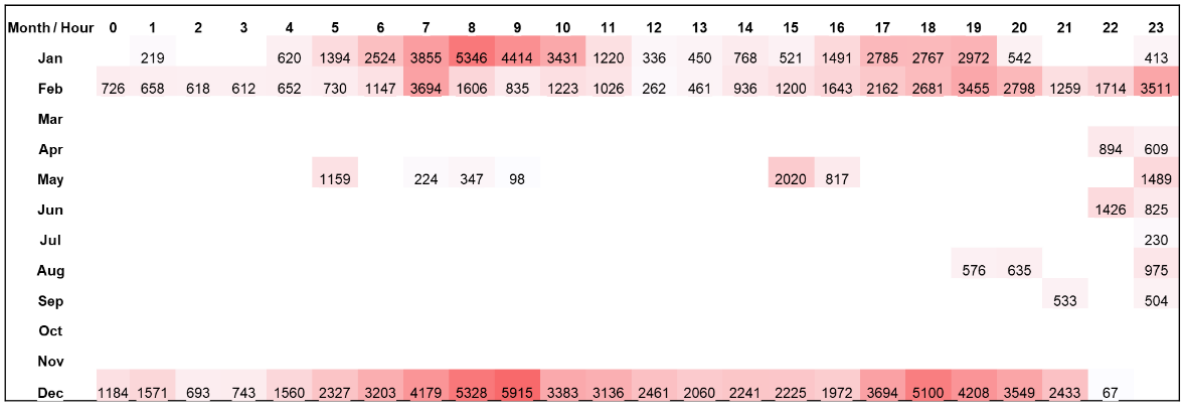


Figure 15. Low End EE scenario shortfall timing – peak magnitude (MW) heatmap

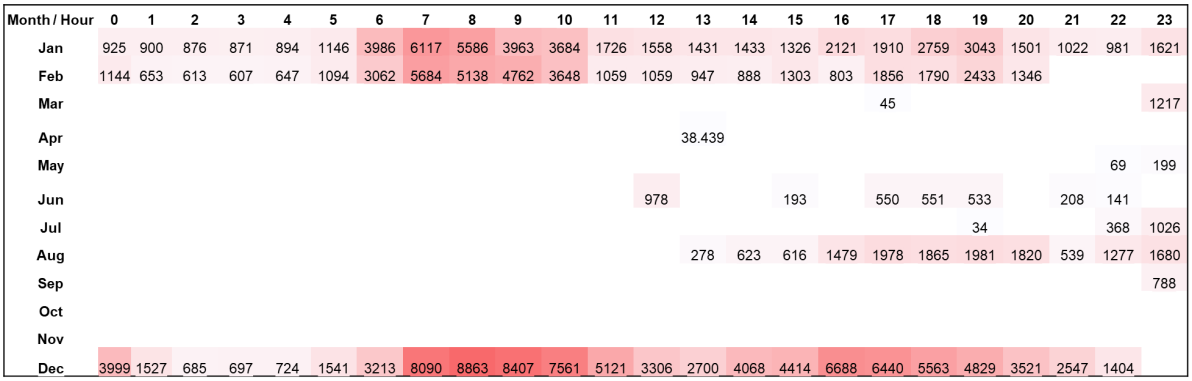


Figure 16. Higher Data Center scenario shortfall timing – peak magnitude (MW) heatmap

Interpreting multiple metrics

Evaluating the distributions of the metric observations alongside the actual shortfalls has a key role in this assessment – better understanding a multi metric approach with limits on frequency, duration, and magnitude of shortfalls (and therefore emergency measures). As the Reference scenario is adequate, the Low End EE scenario provides a good example to discuss given that duration and energy metrics are satisfied and the frequency and peak metrics are violated. Recall that the while the Peak VaR metric is 367 MW higher than the threshold, only 20% of all shortfall peaks are below 300 MW. In other words, while adding 367 MW of perfect capacity would theoretically satisfy the Peak VaR metric (protect against the tail-end risk 39-in-40 years), it might only mitigate 20% of shortfalls, resulting in LOLEV that still exceeds the threshold. Thus, protecting against a distributional peak doesn't automatically protect against overall frequency of events.

This highlights why (a) all metrics must be satisfied to be deemed adequate, and (b) no metric should be considered the binding metric. Rather, it is possible that the emphasis of risk between frequency, duration, and magnitude will vary by scenario (i.e. future conditions and circumstances). Instead of using the word "binding", another suggestion is the to frame it as which metric needs a larger investment (cost/resources) to mitigate while ensuring all metrics are satisfied. While discussing potential solutions for adequacy challenges is outside the scope of the Council's adequacy assessments, this discussion extends into future Power Plan work.

Conclusion

While the region is facing substantial load growth uncertainty, the 2021 Power Plan resource strategy, with the alleviating circumstances of announced coal-to-gas conversions and expanded transmission capacity, are found to provide an adequate system in the Reference Case. Thus, assuming the Reference Case is the trajectory, continued implementation of the strategy, including ensuring sufficient reserves and acquiring another two years of energy efficiency and renewables, not retiring thermal plants through coal-to-gas conversions, and expanded transmission capacity offset the adequacy challenge of increased loads of anticipated data centers and electric vehicles.

However, achieving the low end of the energy efficiency target offers more risk to maintain regional adequacy. The low end of EE, alongside the resource strategy, does not fully mitigate challenges of increased loads in 2029 despite the alleviating circumstances of not retiring thermal plants and expanded transmission. The risk of shortfall frequency and peak magnitude persist with expectation that shortfalls may occur throughout the days in winter (though greatest magnitudes in morning/evening ramp hours), and additional challenges in spring and summer.

Should tech sector load forecast accelerate, driven by higher data center load, and reach the high end of the trajectories, the region will not be adequate. The ~1,600 MW of increased load associated with additional data center load growth above the reference case causes the scenario to violate all adequacy metrics and trigger larger seasonal challenges.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-138:
Bonneville 2024 Fact Sheet

BPA Facts

INFORMATION IS FOR FISCAL YEAR 2024, UNLESS OTHERWISE NOTED.

Profile

The Bonneville Power Administration is a nonprofit federal power marketing administration based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric dams in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington.

BPA provides about one-third of the electric power generated in the Northwest, primarily from reliable, dispatchable and flexible hydroelectric resources. BPA also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory. BPA's territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

BPA promotes energy conservation and innovative technologies that improve its ability to deliver on its mission. To mitigate the impacts of the federal dams, BPA implements a fish and wildlife program that includes working with its partners to make the federal dams safer for fish passage.

BPA is committed to public service and seeks to make decisions in a manner that provides opportunities for input from all interested parties. In its vision statement, BPA dedicates itself to providing high system reliability, low rates consistent with sound business principles, environmental stewardship and accountability.

Mission

BPA's mission as a public service organization is to create and deliver the best value for our customers and constituents as we act in concert with others to assure the Pacific Northwest:

- An adequate, efficient, economical and reliable power supply.
- A transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability.
- Mitigation of the impacts on fish and wildlife from the federally owned hydroelectric projects from which BPA markets power.

BPA is committed to cost-based rates, and public and regional preference in its marketing of power. BPA sets its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the federal investment in the system.

Core values

SAFETY

We value safety in everything we do. Together, our actions result in people being safe each day, every day. At work, at home and at play, we all contribute to a safe community for ourselves and others.

TRUSTWORTHY STEWARDSHIP

As stewards of the Federal Columbia River Power System, we are entrusted with the responsibility to manage resources of great value for the benefit of others. We are trusted when others believe in and are willing to rely upon our integrity and ability.

COLLABORATIVE RELATIONSHIPS

Trustworthiness grows out of a collaborative approach to relationships. Internally we must collaborate across organizational lines to maximize the value we bring to the region. Externally we work with many stakeholders who have conflicting needs and interests. Through collaboration we discover and implement the best possible long-term solutions.

OPERATIONAL EXCELLENCE

Operational excellence is a cornerstone of delivering on our vision (system reliability, low rates, environmental stewardship and regional accountability) and will place us among the best electric utilities in the nation.

General information

BPA established	1937
Service area size (square miles)	300,000
Pacific Northwest population	14,735,345
Transmission line (circuit miles)	14,973
BPA substations	258
Employees (FTE)[1]	3,191

1/ As of October 2025.

Customers

Cooperatives	53
Municipalities	42
Public utility districts	28
Federal agencies	7
Investor-owned utilities	6
Direct-service industries	1
Port districts	1
Tribal utilities	3
Total	141
Marketers (power and transmission)[1]	165
Transmission customers	415

Rates

Wholesale power rates[2] (fiscal years 2024–2025)

Priority Firm Tier 1 (AVERAGE[3], UNDELIVERED)	3.47 cents/kWh
Priority Firm Avg. Tier 1 + Tier 2 (UNDELIVERED)	3.58 cents/kWh
Priority Firm Exchange (AVERAGE, UNDELIVERED)	7.50 cents/kWh
Industrial Firm (AVERAGE, UNDELIVERED)	4.14 cents/kWh
New Resources (AVERAGE, UNDELIVERED)	8.54 cents/kWh

2/ The rates shown do not include the cost of transmission. They also do not include the impact of the Reserves Distribution Clause.
3/ The actual rate paid by an individual customer will vary according to the shape of the load and the products and services purchased.

Transmission rates[4] (fiscal years 2024–2025)

Network rates

Long-Term Firm	$1.648/kW-month
Short-Term	0.474 cents/kWh

Southern Intertie rates

Long-Term Firm	$1.118/kW-month
Short-Term	1.029 cents/kWh

4/ Reflects the rates for point-to-point transmission service. All short-term firm and nonfirm rates are downwardly flexible.

Financial highlights[5]

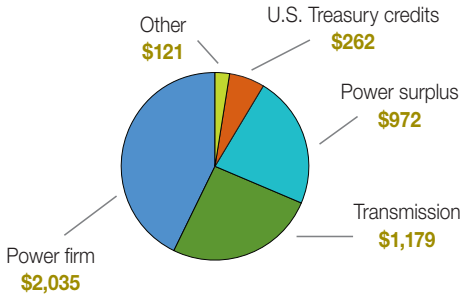
For the Federal Columbia River Power System
($ in millions)

Total operating revenues[6]	$4,569
Total operating expenses	4,357
Net operating revenues	212
Total interest expense and other income, net	344
Net revenues	$ (132)

5/ This information is consistent with BPA's 2024 Annual Report.
6/ For additional information, please visit the 2024 Annual Report at bpa@gov.

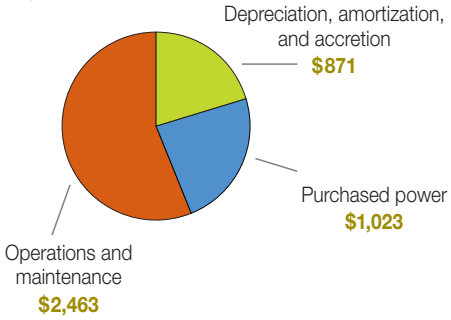
Disaggregated revenues

($ in millions)



Operating expenses[7]

($ in millions)



7/ All intracompany and intercompany accounts and transactions have been eliminated from the FCRPS financial statements.

Transmission system

Operating voltage	Circuit miles
1,100 kV	1.3
1,020 kV	264.3[8]
500 kV	4,734.0
345 kV	569.8
287 kV	0.7
230 kV	5,541.3
161 kV	119.3
138 kV	61.1
115 kV	3,524.3
below 115 kV	157.1
Total[9]	14,973.2

8/ BPA's portion of the PNW/PSW direct-current intertie. The total length of this line from The Dalles, Oregon, to Los Angeles, California is 846 miles.
9/ Total circuit miles as of August 2025.

Federal hydro projects

Name	River, state	In service	Max capacity
Albeni Falls	Pend Oreille, ID	1955	49 MW
Anderson Ranch	*Boise, ID*	*1950*	*40 MW*
Big Cliff	N. Santiam, OR	1953	23 MW
Black Canyon	*Payette, ID*	*1925*	*10 MW*
Boise River Diversion	*Boise, ID*	*1912*	*3 MW*
Bonneville	Columbia, OR/WA	1938	1,216 MW
Chandler	*Yakima, WA*	*1956*	*12 MW*
Chief Joseph	Columbia, WA	1958	2,614 MW
Cougar	McKenzie, OR	1963	29 MW
Detroit	N. Santiam, OR	1953	126 MW
Dexter	Middle Fork Willamette, OR	1954	17 MW
Dworshak	Clearwater, ID	1973	460 MW
Foster	S. Santiam, OR	1967	23 MW
Grand Coulee[10]	*Columbia, WA*	*1942*	*7,049 MW*
Green Peter	S. Santiam, OR	1967	92 MW
Green Springs	*Emigrant Crk, OR*	*1960*	*17 MW*
Hills Creek	Middle Fork Willamette, OR	1962	35 MW
Hungry Horse	*Flathead, MT*	*1953*	*428 MW*
Ice Harbor	Snake, WA	1962	695 MW
John Day	Columbia, OR/WA	1971	2,484 MW
Libby	Kootenai, MT	1975	605 MW
Little Goose	Snake, WA	1970	932 MW
Lookout Point	Middle Fork Willamette, OR	1953	138 MW
Lost Creek	Rogue, OR	1977	56 MW
Lower Granite	Snake, WA	1975	932 MW
Lower Monumental	Snake, WA	1969	932 MW
McNary	Columbia, OR/WA	1952	1,127 MW
Minidoka	*Snake, ID*	*1909*	*28 MW*
Palisades	*Snake, ID*	*1958*	*176 MW*
Roza	*Yakima, WA*	*1958*	*13 MW*
The Dalles	Columbia, OR/WA	1957	2,052 MW
Total (31 dams)			22,391 MW

Owned and operated by the U.S. Army Corps of Engineers (21 dams, 14,637 MW)
Owned and operated by the Bureau of Reclamation (10 dams, 7,776 MW)
10/ Includes pump generation.

BPA resources[11]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January) 13,458 MW
Hydro . . . . . 11,828 MW (88%)
Nuclear . . . . . 1,178 MW (9%)
Firm contracts and other resources . . . . 452 MW (3%)
Wind . . . . . 0 MW (0%)

Firm energy (12-month annual avg.) 8,038 aMW
Hydro . . . . . 6,662 aMW (83%)
Nuclear . . . . . 1,116 aMW (14%)
Firm contracts and other resources . . . 227 aMW (3%)
Wind . . . . . 33 aMW (<1%)

11/ The Resource Program provides analysis and insight into long-term, least-cost power resource acquisition strategies.

Regional resources[12]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January) 40,202 MW
Hydro . . . . . 24,046 MW (60%)
Natural gas . . . . . 6,288 MW (16%)
Coal . . . . . 4,195 MW (10%)
Cogeneration . . . . . 3,179 MW (8%)
Nuclear . . . . . 1,178 MW (3%)
Imports . . . . . 1,065 MW (3%)
Other Renewables . . . . . 182 MW (<1%)
Wind . . . . . 0 MW (<0%)
Other miscellaneous resources . . . . . 31 MW (<1%)

Firm energy (12-month annual avg.) 28,382 aMW
Hydro . . . . . 12,081 aMW (43%)
Natural gas . . . . . 5,373 aMW (19%)
Coal . . . . . 3,751 aMW (13%)
Cogeneration . . . . . 2,737 aMW (10%)
Wind . . . . . 2,200 aMW (8%)
Nuclear . . . . . 1,116 aMW (4%)
Imports . . . . . 588 aMW (2%)
Other renewables . . . . . 159 MW (<1%)
Solar . . . . . 352 aMW (<1%)
Other miscellaneous resources . . . . . 26 aMW (<1%)

12/ Forecast figures from BPA's "2024 Pacific Northwest Loads & Resources Study," tables 2–6, 2–7, 3–3. Firm resource projections before adjustment for reserves, maintenance and transmission losses. The hydro capacity is reduced by an operational "idle capacity" adjustment to estimate the monthly maximum operational capability that is available to meet the 120-hour peak load for firm water conditions.

Federal generation

Hydro generation . . . . . 6,244 aMW
Total generation . . . . . 7,392 aMW
60-min. hydro peak generation . . . . . 11,121 MW
60-min. total peak generation . . . . . 12,239 MW
All-time 60-min. total peak generation record (June 2002). . . . . 18,139 MW

Fish and wildlife

($ in millions)

BPA F&W program expense $272.2
Direct funded expenditures 103.8
Interest, depreciation and amortization expenses 101.2
Total direct costs $477

Operational costs:
Replacement power purchases 856.2
Estimated forgone power revenues 36.6

Total F&W costs for FY 2024[13] $1,370

13/ Program expenses include integrated program and action plan/high priority. Totals may not equal sum of components due to rounding.

Energy efficiency[14]

	FY 2024	Total[15]
Residential programs	7.5 aMW	563.7 aMW
Commercial programs	6.9 aMW	466.7 aMW
Industrial programs	10.3 aMW	363.9 aMW
Agricultural programs	1.6 aMW	77.0 aMW
Multi-sector programs	0 aMW	108.9 aMW
Federal	1.3 aMW	22.8 aMW
Utility distribution system	0.2 aMW	11.3 aMW
Improved building codes	0 aMW	188.5 aMW
NEEA[16] Net Market Effects	7.8 aMW	371.3 aMW
Momentum Savings[17]	TBD	359.7 aMW
Total aMW saved[18]	35.6 aMW	2,533.8 aMW

14/ All figures are preliminary and subject to final revision.
15/ Cumulative total, FY1982–2024.
16/ Northwest Energy Efficiency Alliance.
17/ Momentum Savings are updated at the end of each Power Planning period. Totals reflect achievements made through the 6th Power Plan.
18/ Data aligns with 2024 Annual Review and may be adjusted from past versions of BPA Facts.

Points of contact

GENERAL BPA OFFICES AND WEBSITES

BPA Headquarters 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-3000; *www.bpa.gov*

BPA Visitor Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-INFO [4636]; 800-622-4520

Public Engagement P.O. Box 14428, Portland, OR 97293; 800-622-4519; *www.bpa.gov/comment*

Washington, D.C., Office Forrestal Bldg., Room 8G-061, 1000 Independence Ave. S.W., Washington, D.C. 20585; 202-586-5640

Crime Witness Program To report crimes to BPA property or personnel; 800-437-2744

TRANSMISSION SERVICES

Transmission Services Headquarters P.O. Box 491, Vancouver, WA 98666-0491; 503-230-3000

Ross Complex 5411 N.E. Highway 99, Vancouver, WA 98663; 503-230-3000"

Van Mall One Park Place 7600 NE 41st Street, Vancouver WA 98662, 503-230-3000

Covington District 28401 Covington Way S.E., Kent, WA 98042; 253-638-3700

Eugene District 86000 Hwy. 99 S., Eugene, OR 97405; 541-988-7401

Idaho Falls Regional Office 1350 Lindsay Blvd., Idaho Falls, ID 83402; 208-612-3100

Kalispell District 2520 U.S. Hwy. 2 E., Kalispell, MT 59901; 406-751-7802

Longview District 3750 Memorial Park Drive, Longview, WA 98632; 360-414-5600

Olympia Regional Office 5240 Trosper Road S.W., Olympia, WA 98512; 360-570-4305

Redmond District 3655 S.W. Highland Ave., Redmond, OR 97756; 541-516-3200

Salem District 2715 Tepper Lane N.E., Keizer, OR 97303; 503-304-5900

Snohomish District 914 Ave. D, Snohomish, WA 98290; 360-563-3600

Spokane District 2410 E. Hawthorne Road, Mead, WA 99021; 509-468-3002

The Dalles District 3920 Columbia View Drive E., The Dalles, OR 97058; 541-296-4694

Tri-Cities District 2211 N. Commercial Ave., Pasco, WA 99301; 509-544-4702

Wenatchee District 13294 Lincoln Park Road, East Wenatchee, WA 98802, 509-886-6000

POWER SERVICES

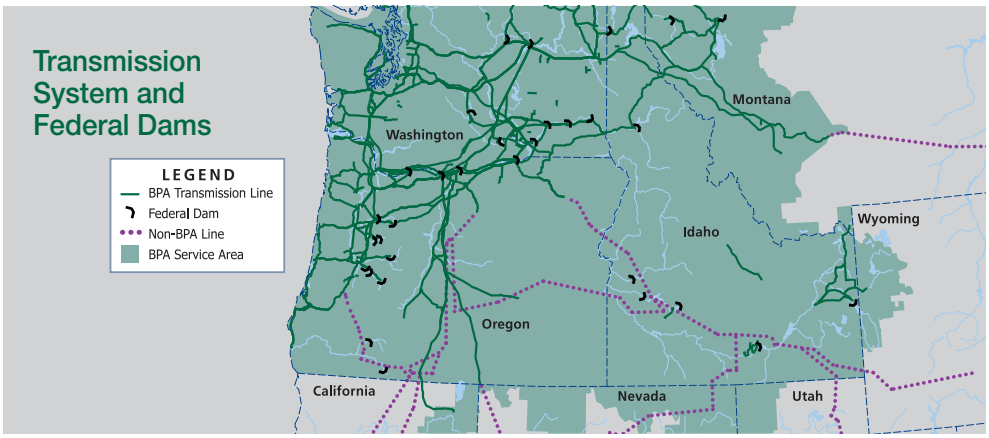
Boise Customer Service Center 950 W. Bannock St., Suite 805, Boise, ID 83702; 208-670-7406

Eastern Area Customer Service Center P.O. Box 789, Mead, WA 99021; 509-822-4591

Montana Customer Service Center P.O. Box 640, Ronan, MT 59864; 406-676-2669

Seattle Customer Service Center 915 Second Ave., Suite 3360, Seattle, WA 98174; 206-220-6770

Western Area Customer Service Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-5856



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-139:
Bonneville Day-Ahead Market Policy

Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville's decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,[1] including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest[2] from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.[3] See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams

Bonneville's statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

[1] In this Policy, the "Pacific Northwest" or "region" has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).
[2] Bonneville Power Administration, BPA Facts (Sept. 2024), *available at* https://www.bpa.gov/about/newsroom/fact-sheets.
[3] *Id.*; *see also* Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) ("The White Book"), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.[4] The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)[5] that are individually responsible for ensuring the reliable operation of the electric grid.[6] The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.[7] WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).[8] Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).[9] RTOs and ISOs manage about 60% of the U.S. electric power supply[10] and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.[11] All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

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[4] For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* https://www.ferc.gov/electric-power-markets.

[5] A BAA is defined as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Id.*

[6] BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* https://www.nerc.com) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see* WECC, *available at* https://www.wecc.org).

[7] WECC, About WECC, *available at* https://www.wecc.org/about/about-wecc.

[8] FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier "power pool" concept. Several groups of transmission owners then formed ISOs, some from existing power pools Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

[9] In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

[10] U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20marketers%20and%20energy%20traders.

[11] An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* https://energyknowledgebase.com/topics/ferc-order-2000.asp.

(LMP)[12] to create an "economic dispatch."[13] Section 1234 of the Energy Policy Act of 2005 defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[14]

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.[15] Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.[16]

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.[17] CAISO's overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[18] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA's boundaries have enough generation in their operating plan to satisfy the load and obligations for that

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[12] *See* SPP Markets+ Tariff, Attach. A § 3.2, *available at* https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf ("The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)"). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), *available at* https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

[13] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

[14] 42 U.S.C. § 16432.

[15] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), *available at* https://www.westerneim.com/Pages/About/default.aspx.

[16] *See* CAISO, How the Markets Work (2025), *available at* https://www.westerneim.com/Pages/About/HowItWorks.aspx.

[17] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025). *available at* https://www.westerneim.com/Pages/About/default.aspx.

[18] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.

market participant and BA.[19] The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.[20] As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.[21]

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,[22] and SPP began development of Markets+ in 2022.[23,24] A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.[25] Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

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[19] *See* SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019)*, available at* https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.

[20] *See* SPP, Western Energy Imbalance Service Market (2025), *available at* https://www.spp.org/western-services/weis/.

[21] SPP, Annual Report 2022 at 4, *available at* https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.

[22] *See* CAISO, Initiative: Extended day-ahead market, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[23] *See* SPP, Markets+, *available at* https://www.spp.org/western-services/marketsplus/.

[24] SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.

[25] FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* https://www.ferc.gov/OPP/western-markets-explainer.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.[26] The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilaterial world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

[26] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

that relieves a transmission constraint).[27] This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.[28] According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.[29]

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED[30] accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.[31] "Unit commitment" determines the optimal

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[27] *See* Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), *available at* https://woodsinstitute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

[28] *See* Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

[29] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

[30] As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

[31] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

combination of resources to bring online from those that are available for some or all of the operating day.[32] "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.[33] To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.[34] These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.[35] Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

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[32] CAISO, Technical Bulleting 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.
[33] *Id.* § 3.
[34] Referred to as "Reliability Unit Commitment" in Markets+ and "Residual Unit Commitment" in EDAM.
[35] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.[36]

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[37] (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

[36] *See* Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[37] 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville's comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville's continued decision process • Evaluation of market governance developments • Bonneville's supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville's day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville's evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville's participation is supported by a sound business rationale.

- Strategy – Bonneville's participation is consistent with Bonneville's 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville's statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville's customers is one of the most important aspects of Bonneville's various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources' availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough "steel in the ground" (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their

expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)[38] to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

[38] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.[39] The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops[40] exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract[41] that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.[42] Bonneville markets power from the federal hydropower system, Columbia Generating station,

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[39] Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.

[40] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[41] Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[42] Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf (full comments available at https://publiccomments.bpa.gov/CommentList.aspx?ID=421); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.[43] These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

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at https://publiccomments.bpa.gov/CommentList.aspx?ID=480); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market).

[43] Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville's Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25[44] BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

[44] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.[45] The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

[45] For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.[46] Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of $1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded $100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

[46] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.[47]

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a "net cost," which indicated whether the WMEG member should expect a cost or benefit. Again, a positive "net cost" indicated cost to the WMEG member because of day-ahead market participation, and a negative "net cost" indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3's Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)[48]

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

[47] For results, see Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (*see* Workshops, Oct. 23, 2023, WMEG Materials).
[48] Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), *available at* http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3._E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_Final.pdf.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue[49] (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

[49] The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.[50] Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as "Net Cost without Wheeling" for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a "business as usual" (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

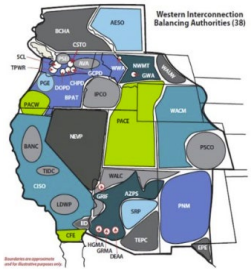
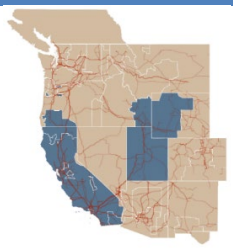
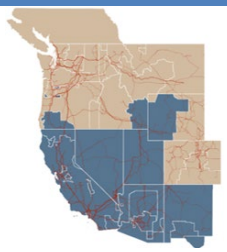
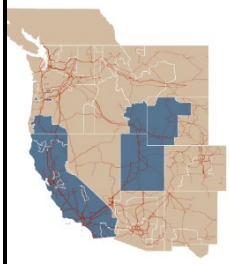
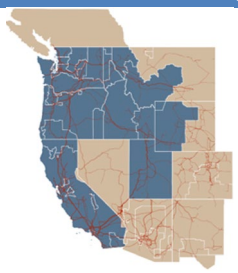
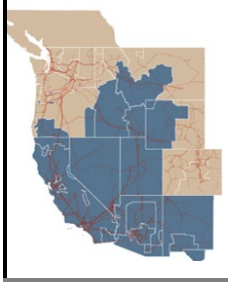
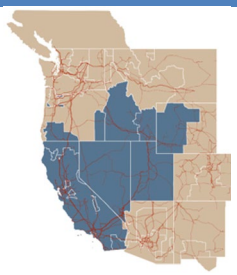
1) The BAA participates in EDAM,

2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

[50] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

Business-as-Usual	Main Split
 This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage	 PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
EDAM Bookend	**Alternative Split 1**
All US WECC in EDAM; British Columbia Hydro only in Markets+	 PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
Markets+ Bookend	**Alternative Split 2**
 PAC, CAISO, Los Angeles Department of Water & Power. Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)	 PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
Alternative Split 3	**Alternative Split 4**
 PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+	 PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville's initial WMEG results are available on Bonneville's website.[51]

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	Footprint									
2		Cost/Benefit Category	BAU (2026)	EDAM Bookend (2026)	Main Split (2026)	Markets Bookend (2026)	Alt Split 1 (2026)	Alt Split 2 (2026)	Alt Split 3 (2026)	Alt Split 4 (2026)
3	Category Value	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		**Net Costs w/o Wheel**	**-339**	**-475**	**-369**	**-349**	**-359**	**-451**	**-233**	**-277**
9	Δ Category vs. BAU	Δ Load Cost		23	3	-19	-2	61	-81	-60
10		Δ Gen Revenue		-149	-29	12	-19	-174	189	121
11		Δ Congestion Revenue		-10	-3	-3	2	1	-1	2
12		Δ GhG Revenue		0	-1	-1	-1	0	-1	-1
13		**Δ Net Cost w/o Wheel**		**-136**	**-30**	**-10**	**-19**	**-112**	**107**	**62**

Green = Benefit Greater than BAU **Red = Increased Cost from BAU**

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,[52] the reduction in projected benefits relative to BAU is driven by generation revenues declining[53] more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville's Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville's WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville's PCM results are

[51] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[52] Alt Split 3 Load Cost reduced by $81m as shown in cell I9; Alt Split 4 Load Cost reduced by $60m as shown in cell J9.

[53] Alt Split 3 Gen Rev declines by $189m as shown in cell I10; Alt Split 4 Gen Rev declines by $121m as shown in cell J10.

available on Bonneville's website.[54]

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the "generation revenue" category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.[55]

5.1.1.4.1. Supplemental Analysis Tasks

1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

1) Market Interactions with WRAP | Understanding the potential difference in ability of either market's rules & practices to enable realization of RA benefits.
2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

[54] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[55] *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

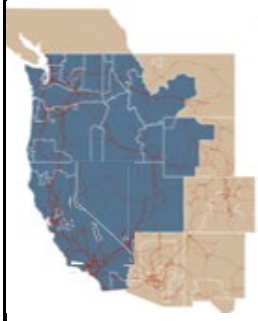
Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	**EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***
Non-CA Westwide Markets+	
EDAM: California LSE's Only **Markets+:** Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results[56]

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

	Supplemental Analysis																						
	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)	T2 | Alt Split 4A M2M (2026)	T2 | Alt Split 4A M2M2 (2026)	T2 | Alt Split 4A M2M3 (2026)	T2 | Main Split M2M (2026)	T2 | Main Split M2M2 (2026)	T2 | Main Split M2M3 (2026)	T3 | BAU Low Water (2026)	T3 | BAU Low Water & Stressed Loads (2026)	T3 | Alt Split 4A Low Hydro (2026)	T3 | Alt Split 4a Low Hydro & Stressed Loads (2026)	T3 | EDAM Bookend Low Water (2026)	T3 | EDAM Bookend Low Water & Stressed Loads (2026)	T4 | Alt Split 4A BPA EIM ONLY (2026)	T4 | Alt Split 4A BPA EIM ONLY Low Hydro Stress Load (2026)	T4 | EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 | Alt Split 4A Straw (2026)	T5 | Hypothetical New Additional TX (2026)	T10 | Non-CA WestWide M+ (2026)	T11 | Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs	921	739	818	874	910	961	981	983	1104	1132	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1182	-1156
	Congestion Rev	-50	-65	-59	-56	-57	-52	-54	-57	-30	-30	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GhG Rev	0	0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Net Cost w/o Wheel	**-138**	**-30**	**-98**	**-148**	**-182**	**-192**	**-208**	**-222**	**4**	**15**	**16**	**26**	**-50**	**-42**	**-160**	**5**	**14**	**-61**	**-123**	**-207**	**-195**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost		-182	-103	-47	-11	40	60	62	183	211	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU | Generation Rev		305	153	43	-26	-91	-125	-139	-61	-78	108	73	-45	-62	11	-63	36	226	163	-42	-15
	Δ BAU | Congestion Rev		-15	-9	-6	-7	-2	-4	-7	20	20	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU | GhG Rev		0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Δ BAU | Net Cost w/o Wheel		**108**	**41**	**-10**	**-44**	**-54**	**-69**	**-84**	**142**	**153**	**154**	**164**	**89**	**96**	**-22**	**143**	**152**	**78**	**15**	**-69**	**-57**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	182		79	136	171	222	242	245	366	393	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A | Gen Rev	-305		-152	-262	-331	-397	-430	-445	-366	-384	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A | Congestion Rev	15		6	9	8	13	11	8	35	35	26	26	26	27	-4	34	34	7	-23	19	21
	Δ Alt 4A | GhG Rev	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Wheel	**-108**		**-67**	**-118**	**-152**	**-161**	**-177**	**-192**	**35**	**45**	**47**	**56**	**-19**	**-12**	**-129**	**36**	**44**	**-30**	**-92**	**-177**	**-165**

Green = Benefit Greater than anchor point Red = Increased Cost than anchor point

**Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[56] During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the "Generation Revenue" category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category				Declining Hurdle Rates		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results[57]

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

[57] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

Figure 2 | E3 PCM results

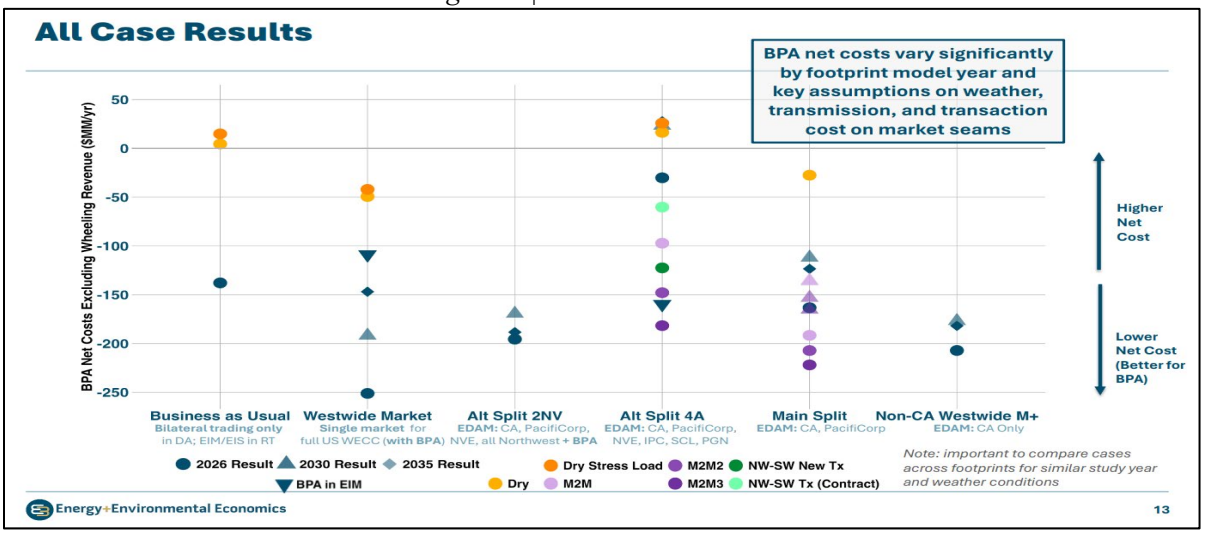


***Figure 2 Takeaway*:** Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

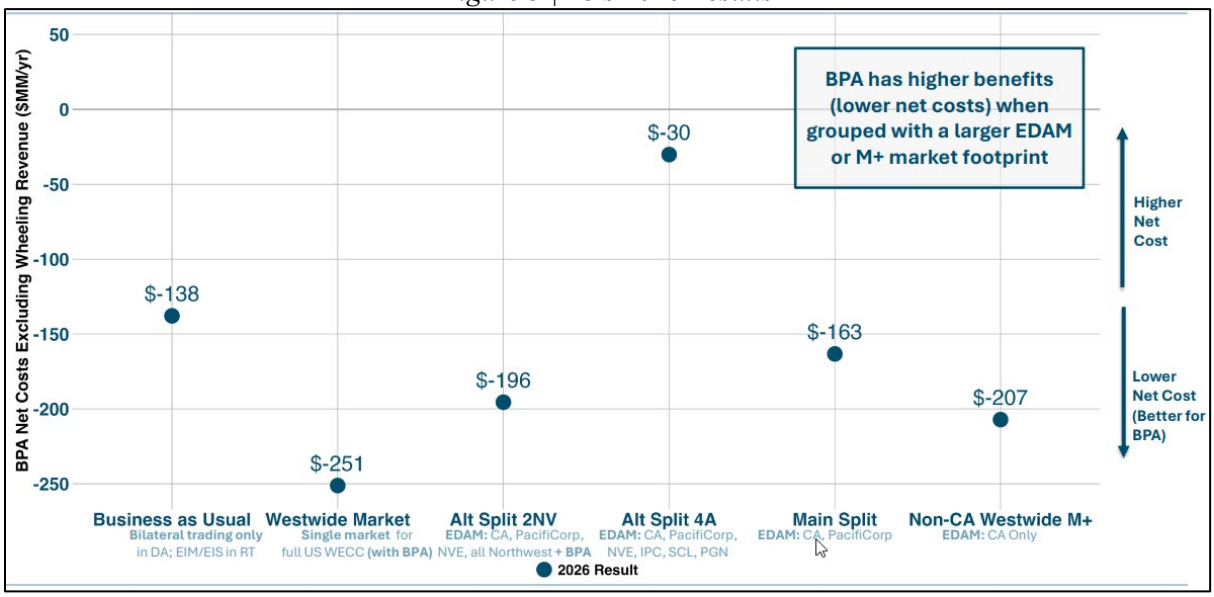


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	**Cost/Benefit Category**	**BAU (2026)**	**T9 | Alt Split 4A (2026)**
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-30**
9			
10	Δ BAU | Load Cost		-182
11	Δ BAU | Generation Rev		305
12	Δ BAU | Congestion Rev		-15
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**108**

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1			Supplemental
2	**Cost/Benefit Category**	**BAU (2026)**	**T11 | Alt Split 2NV (2026)**
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-195**
9			
10	Δ BAU | Load Cost		-48
11	Δ BAU | Generation Rev		-15
12	Δ BAU | Congestion Rev		6
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**-57**

***Figure 3 Takeaway*: Footprint is a primary driver of results.**

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by $182 million (see cell R10), but generation revenues go down by more ($305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A ($48 million, see cell AK10), but an increase to generation revenue ($15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville

in EDAM.

Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of $30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly $200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly $60 million better. Examining the categorical differences between cases shows that $48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from $251 million to $109 million. Conversely, Alt Split 4A sees an increase in benefit from $30 million to $160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario

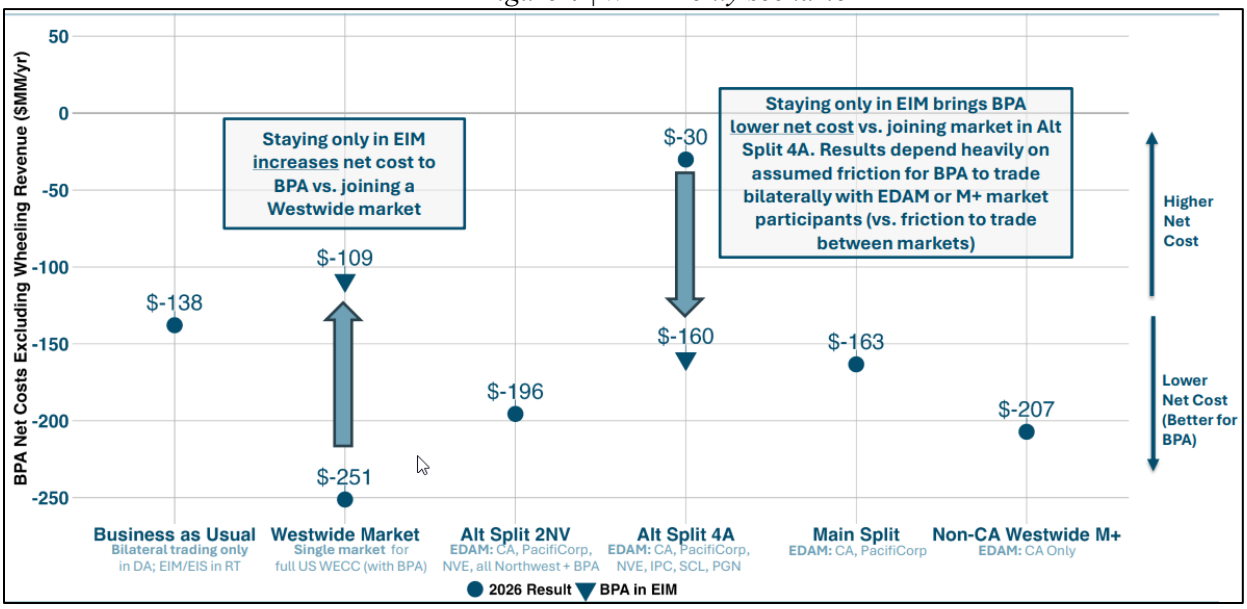


***Figure 4 Takeaway*: WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.**

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	**Supplemental Analysis**					
	M2M		**M2M2**		**M2M3**	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	**DA**	**Weighted Average OATT +$6 adder**	**DA**	**Weighted Average OATT + $3 adder**	**DA**	**50% of Weighted Average OATT + $3 adder**
	M2M DA = $10.50/MWh		**M2M2 DA = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	
	RT	**Weighted Average OATT + $3 adder**	**RT**	**Weighted Average OATT + $3 adder**	**RT**	**50% of Weighted Average OATT + $3 adder**
$14.50 /MWh in DA & RT	**M2M RT = $7.50/MWh**		**M2M2 RT = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	

**** Adder encompasses value for Friction & Congestion Risk***

Figure 5 | Hurdle Rate Sensitivities

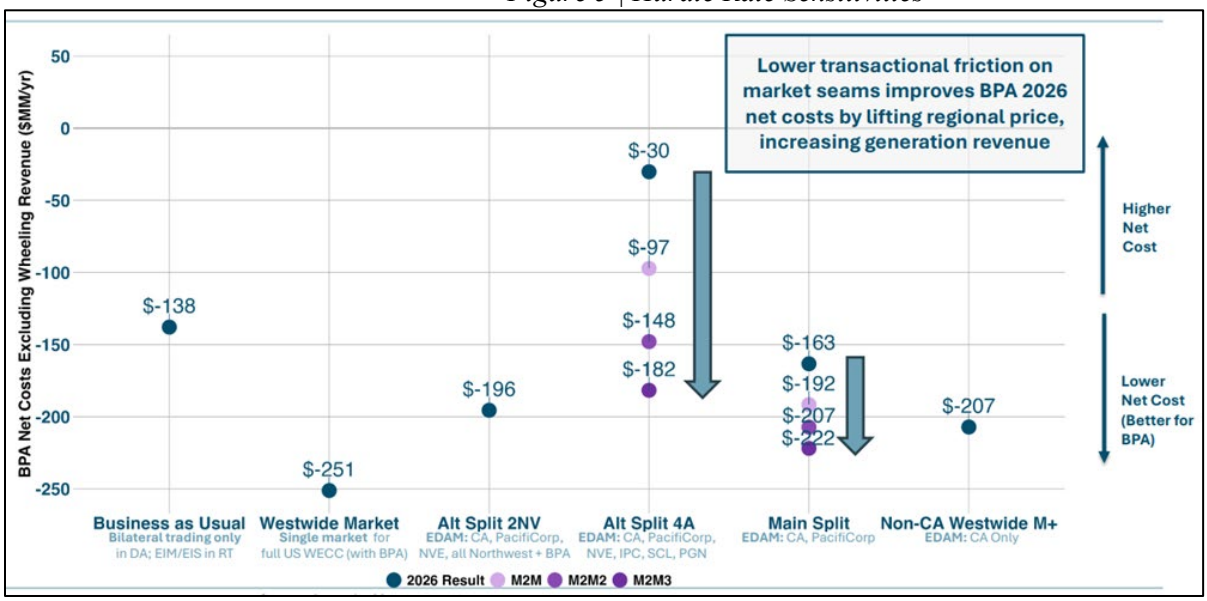


***Figure 5 Take-away*: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.**

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

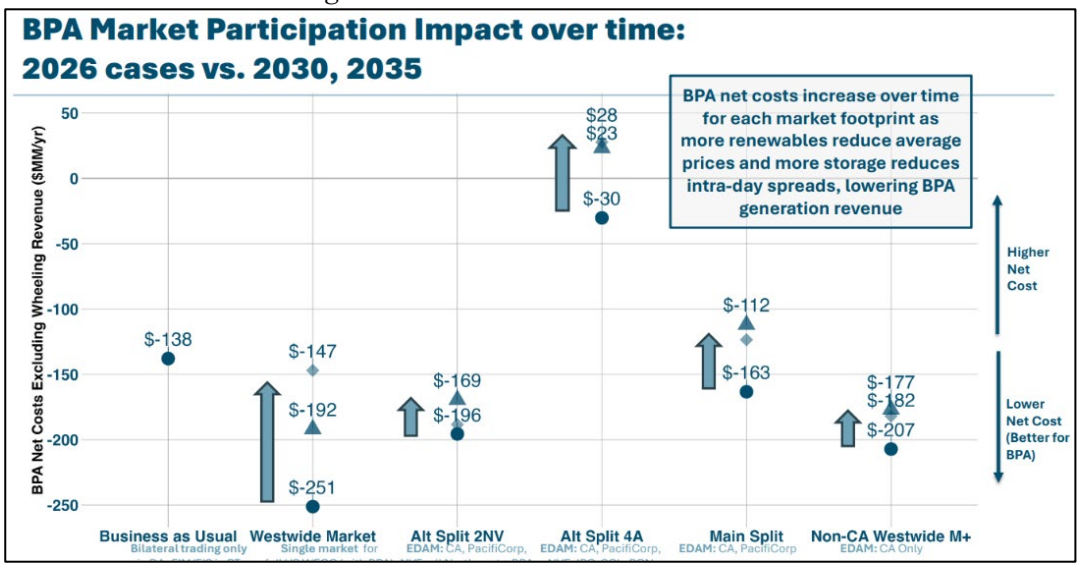


***Figure 6 Takeaway*: Changing regional resource mix may result in declining benefits over time.**

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[58] and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[59] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[60] and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

[58] Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.
[59] Power Revenue Requirement Study - BP-26-E-BPA-02.
[60] Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.[61]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[62] This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.[63]

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.[64] Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

[61] Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.
[62] BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[63] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue).
Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[64] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.[65] This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

[65] See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.[66,67] This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.[68] Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

[66] *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").
[67] *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).
[68] For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from $20 million to $200 million over time.[69] Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.[70] The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.[71] The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.[72]

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

[69] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[70] SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).
[71] CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).
[72] For example, for potential wheeling revenue shortfalls "the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate." *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.[73] CAISO estimates the standard fee to be $1.2 million for each BAA that elects to join EDAM.[74] Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.[75] CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between $2.5 million and $3 million, and the implementation time frame to be between eighteen and twenty-four months.[76]

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately $26.8 million.[77] The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate $29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between $13 and $15 million annually.

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[73] CAISO EDAM Filing, Transmittal Letter at 105-07.
[74] CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[75] CAISO EDAM Filing, Transmittal Letter at 105.
[76] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[77] *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator ($M)

Estimated Fees for Bonneville	**On-going Participation Fee (Paid to MO)***	**One-time Implementation Fee (Paid to MO)***
EDAM	~$29M /year	~$3M
Markets+	~$15M /year	~$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	**Non-Labor**	**Incremental Labor**	**Total Cost (Non-Labor + Incremental Labor)**
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

[78] CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville's existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP's existing systems and processes, which are different than CAISO's and will require system modifications to enable Bonneville's market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville's Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville's Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as "the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders" and that "decision-making and stakeholder engagement occurs in a transparent and inclusive manner."[79] Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville's ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.[80] Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market's design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

[79] Section 4.1.6 above.

[80] *See, e.g.*, Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), *available at* https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[81] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.[82] While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,[83] which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).[84] MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

[81] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.
[82] Cal. Pub. Utils. Code § 345.5 (2025).
[83] *See* Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), *available at* https://www.westernenergyboard.org/wwgpi/.
[84] SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether 5B 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.[85] All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.[86] WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.[87] For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.[88] While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

[85] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.
[86] SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).
[87] Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), *available at* https://www.westernpowerpool.org/news/wrap-area-map.
[88] Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), *available at* https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.[89]

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.[90]

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markest+.[91] As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,[92] the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation[93] issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

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[89] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

[90] SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

[91] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

[92] WECC, 2024 State of the Interconnection (Sept. 2024), *available at* https://feature.wecc.org/soti/index.html.

[93] For more information see FERC, Energy Price Formation (June 17, 2020), *available at* https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.[94] Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.[95] The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

[94] For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.

[95] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.[96] Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME[97] effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals[98]. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders[99]. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,[100] scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

[96] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.

[97] See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[98] *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[99] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[100] *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.[101] These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.[102] Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.[103] The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

[101] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

[102] SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

[103] The CAISO EDAM tariff provides:

> **Transmission Not Available in the Day-Ahead Market**. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)[104] in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents[105] are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at $25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers $35/MW. The load will pay $35/MW rather than $25/MW because its incremental MWs are served by the other resource offering $35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.[106] The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

n most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.[107] Transfer revenue is

[104] Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

[105] Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

[106] To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

[107] *See* CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.[108] The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.[109] An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.[110] The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.[111] Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."[112] In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."[113] While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.[114] Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

[108] *See id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.
[109] *See id.*
[110] *See id.* § 33.18.4 (CAISO Transmission at EDAM Interties).
[111] *PacifiCorp*, FERC Docket No. ER-25-951-000.
[112] *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf.
[113] *Id.* (parentheticals omitted).
[114] *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+.[115]

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[116] However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff.[117] In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate[118]. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs.[119]

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

[115] *See* SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[116] *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[117] *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[118] This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[119] SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.[120] In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

[120] *See, e.g.*, CAISO, Average Emissions Rate Report, *available at* https://www.caiso.com/library/average-emissions-rate-reports.

design (for "Type 1A" attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville's Washington customers. Markets+ design allows participants to register resources as "Type 1A" if they have contracts with load in the GHG Pricing Zone.[121] This "Type 1A" treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This "Type 1A" treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington[122] and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as "Type 1A" resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM's design recognizes contractual commitments[123] but not in an equivalent manner to Markets+ Type 1A treatment. EDAM's design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).[124] Thus, EDAM's design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM's market design, paired with the design of Washington's cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville's preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville's power customers in Washington. This could occur because in-state resources[125] always have the GHG adder[126] in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville's

[121] *See* SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.
[122] Currently, in Bonneville's BAA, only its customers in Washington will have load included in a GHG Pricing area.
[123] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[124] Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. *See* SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.
[125] In-state resources are generally resources physically located in the state with the GHG pricing program (*e.g.*, Washington). However, pursuant to Washington's Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. *See* Wash. Rev. Code § 70A.65.010(42)(c).
[126] A GHG adder represents the monetary value of an individual resource's emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). *See* CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. Markets+ Baseline "Threshold" Run recognizes Bonneville's load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs

For customers located outside Washington, Markets+ design (the "threshold enhanced floating surplus" approach)[127] gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant's total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant's load obligations. Markets+ uses a baseline run that takes those obligations (the "threshold") into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes[128] and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,[129] there is no in-market mechanism that aligns the participant's load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM's baseline run (the "reference pass")[130] takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will "approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[131] As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant's load obligation.[132]

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage[133] is by assuming the load obligations of all market participants external to the GHG pricing area

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[127] *See* SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.
[128] Email exchange between Bonneville and SPP (on file with author).
[129] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[130] *See* CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[131] See CAISO EDAM Filing, Transmittal Letter at 163-69.
[132] The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.
[133] "Leakage" as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.[134]

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,[135] which limits attribution from resources in a BAA where that BAA is a net importer.[136] However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,[137] about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance[138] in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

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Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11. CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

[134] Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

[135] *See* CAISO EDAM Filing, Tariff § 29.32.1.

[136] The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

[137] Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

[138] The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. *See* CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run[139] and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.[140] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.[141] In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.[142] It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

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[139] The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

[140] *See* SPP, Markets+ GHG Task Force, *available at* https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).

[141] *See* CAISO, Greenhouse Gas Coordination Work Group, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group.

[142] CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size[143] in Bonneville's BAA will be subject to the market tariff and rules,

[143] In the WEIM, Bonneville requires all generators above 3 MW to be modeled. *See* Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.[144] Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.[145] The basic energy settlement equations are described in Section 6.6.[146]

All resources participate, but can self-schedule

In the context of the WEIM, "participating resources" are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and "non-participating resources" are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered "participating" because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for "self-scheduling" which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant[147] Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville's Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

[144] *See* Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.
[145] SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).
[146] *See also* SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).
[147] Pursuant to the Markets+ Tariff Definitions: "Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC."

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10

hydro resources.[148] The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,[149] Lower Snake,[150] and Lower Columbia[151] areas).[152]

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

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[148] The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.
[149] Aggregation of Grand Coulee and Chief Joseph Dams.
[150] Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.
[151] Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.
[152] For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.[153] There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.[154]

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

[153] Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

[154] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.[155] Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

[155] *See WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or "INC" capacity is deployed when there is under-generation relative to load and decremental or "DEC" capacity is deployed when there is over-generation relative to load.

Before Bonneville's entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville's own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR[156] is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville's BAA. During times of high river flows, typically in the spring when loads in Bonneville's BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.[157]

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[156] *See* Bonneville Power Administration, Operational Controls for Balancing Reserves, *available at* www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.
[157] *See* Bonneville Power Administration, Oversupply, *available at* www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants[158] will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.[159] Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement[160] for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

[158] *E.g.*, Planned Product customers, independent power producers, etc.
[159] Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.
[160] Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP[161] Service and NITS.[162] PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any another relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

[161] Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf.
[162] Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf.

public workshop 8 on July 18, 2024.[163] Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints[164] (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"[165] their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.[166] Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.[167] Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

[163] Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf.

[164] Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.

[165] SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

[166] Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.

[167] SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag. [168] The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day.[169] These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

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[168] E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

[169] Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), *available at* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf.

6.8.2. Transmission Losses

As energy is physically delivered across a transmission system, there is a natural degradation or "loss" that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is "lost" on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the "donation model" of Transmission Rights by Interchange Rights Holders[170] to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid "double-payment," Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville's current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville's tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

[170] Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and

superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville's decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act[171] to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.[172] Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville's authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[173] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[174] Bonneville's statutes are unique with repeated focus on the business-related aspects of the agency's authority.

Both Congress and the courts have reaffirmed Bonneville's authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing Bonneville's operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

[171] 16 U.S.C. § 832a(f).

[172] Bonneville Power Administration, Energy Imbalance Market Policy, Administrator's Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalancemarket/rod-20190926-energy-imbalance-market-policy.pdf; Bonneville Power Administration, Bonneville's decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.

[173] Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).

[174] Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

> of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.[175]

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.[176] Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that "[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act's passage."[177]

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.[178] As stated in the 1995 Business Plan Record of Decision, Bonneville's objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.[179] The market-driven approach is designed to increase the value of Bonneville's business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.[180] By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville's customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities' participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.[181]

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville's authority to market federal power is included in several statutes: the Bonneville Project Act

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[175] S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.
[176] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).
[177] *Id*.
[178] Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf.
[179] *Id.* at 1.
[180] *Id.* at 11.
[181] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, "[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."[182] Section 4(b) further explains, "in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted."[183] The Flood Control Act of 1944 similarly states that "[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives."[184] Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, "[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."[185] The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

> The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

[182] 16 U.S.C. § 832c(a).

[183] 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) ("[T]he preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." (citing section 4(b) of the Bonneville Project Act)).

[184] 16 U.S.C. § 825s.

[185] 16 U.S.C § 839c(a)

> and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.[186]

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.[187] The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].[188]

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

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[186] H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

[187] As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers . . . . This is a bill to solve a power allocation problem . . . ." 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

[188] 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.[189] It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).[190]

Importantly, section 5(b) contracts are not a response to "competing or conflicting" requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.[191]

Bonneville's ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.[192] If the Administrator "cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency" he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions. [193]

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.[194]

Additionally, Bonneville's participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council's Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville's continued efforts and the benefits that coordination

[189] 16 U.S.C. § 839d(b)-(d).
[190] 16 U.S.C. § 839e(a)-(b).
[191] 16 U.S.C. § 838i(b)(6).
[192] 16 U.S.C. § 839c(b)(5).
[193] *Id.*; 16 U.S.C. § 839c(b)(6).
[194] *See* Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937[195] and the Pacific Northwest Consumer Power Preference Act of 1964[196] specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.[197] Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.[198]

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

[195] 16 U.S.C. § 832 *et seq.*
[196] 16 U.S.C. § 837 *et seq.*
[197] WEIM Policy ROD at 62.
[198] *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

> In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.[199]

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

> The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.[200]

Section 6(l)(2) further provides:

> The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.[201]

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.[202] Interchange energy means energy received by one utility system from another, usually in exchange for

[199] 16 U.S.C. § 832a(b) (emphasis added).
[200] 16 U.S.C. § 839d(l)(1).
[201] 16 U.S.C. § 839d(l)(2).
[202] *See* Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.[203] While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

[203] *See Cal. Energy Comm'n v. Bonneville Power Admin.,* 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.[204]

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.[205] When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.[206] RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery." [207]

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

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[204] *See* Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . . .").

[205] 42 U.S.C. § 16431.

[206] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

[207] *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law . . . ."[208] Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[209] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[210] Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville's proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, 2) based upon the Administrator's total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.[211]

In a day-ahead market, Bonneville's rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville's rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville's rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator's obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville's governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville's authority to determine the terms and conditions of transmission service.[212] In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

[208] *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).
[209] 16 U.S.C. § 839e(i).
[210] 16 U.S.C. § 839e(a)(1).
[211] 16 U.S.C. § 839e(a)(2).
[212] 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.[213]

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

[213] 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found here.

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to

favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville's strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC's requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.[214] Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.[215] In eastern RTOs,/ISOs, they are vertically aligned among roles[216] as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

[214] *E.g.*, Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).
[215] *E.g.*, SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.
[216] *I.e.*, RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC Rules of Procedure *(ROP Section 500, 1.4.1)*, all areas *(geographic or electrical)* are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This "market congestion" or "commercial congestion" may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market's management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities[217] and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

[217] *E.g.*, BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL[218] and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.[219] Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

[218] The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.
[219] Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and interties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the "binding" limit. An indication that congestion is occurring is "price separation" between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.[220]

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market's participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

[220] *See* Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.[221] The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

[221] *See* Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023*)*, *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-140:
2023 Bonneville White Book

BONNEVILLE POWER ADMINISTRATION

2023 Pacific Northwest Loads and Resources Study

April 2023

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

April 20, 2023

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System or to determine BPA revenues or rates.

New for this white book, firm energy planning is based off the tenth percentile of the Tier One System Firm Critical Output (T1SFCO), previously water year 1937. Moving to percentile approach helps avoid any anomaly observed in a single water year. As a prime example, January 1937 being the worst monthly streamflow on record, comparison between this white book and the 2022 White Book, particularly in January 120-Hr (MW) metric, displays the results of this change.

This 2023 White Book presents Federal system and the region's load obligations, contracts, and resources as of December 2022 for operating years (OY) 2024 through 2033. The 2023 White Book includes the following studies:

- **Federal System Analysis**—forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by different energy planning. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 18 aMW to 424 aMW. Except for the first year of the study period, these annual energy deficit projections are greater than those projected in the 2022 White Book. Under median water conditions; the Federal system is projected to have annual energy surpluses through the study period.
  - January 120-Hour Capacity Surplus/Deficits: Under firm water conditions; the Federal system is projected to have January 120-Hour capacity surpluses through most of the study period with the only deficit in OY2033. Surpluses starting at 414 MW for the first year gradually decline to a deficit in the last year of 123 MW. These 120-Hour capacity results are different than those projected in the 2022 White Book largely due to the change in firm water conditions planning. . Under median water conditions; the Federal system is projected to have January 120-Hour capacity surpluses over the study period.

- **PNW Regional Analysis**—forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions; the PNW region is projected to have an annual energy surplus as large as 2,316 aMW in OY 2024, slowly decreasing to a deficit of 61 aMW by OY 2033. These annual energy projections are more surplus throughout the study period than was forecasted in the 2022 White Book. Under median water conditions; the PNW region would see even larger energy surpluses over the study horizon.
  - January 120-Hour Capacity Surplus/Deficits: Under firm water conditions; the PNW region is projected to have January 120-Hour capacity deficits over most of the study period ranging from 774 MW to 3,506 MW, except for the first two years (OY 2024 and OY 2025) which are slightly surplus. These deficit projections are much less than those shown in the 2022 White Book. Under median water conditions; the PNW region has January 120-Hour capacity surpluses through the final year of this study.

BPA is currently starting the development of its 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer term resources outlook for the region; such as resource retirements and development, resource adequacy and the efforts surrounding it, carbon free resource requirements, and the most recent Climate Resiliency efforts. As with resources, there is also much uncertainty with loads including the potential for electrification. The 2023 White Book is available on BPA's website: *https://www.bpa.gov/energy-and-services/power/resource-planning* or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. Available report list can be found in Appendix A.

Please send questions and/or comments to Steve Bellcoff (503) 230-3319.

Sincerely,

ROBERT PETTY Digitally signed by ROBERT PETTY
Date: 2023.04.20 13:12:12 -07'00'

Robert Petty
Manager, Power and Operations Planning

Enclosure

2023 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
April 2023

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

The Dalles Dam is located roughly 190 miles upstream from the mouth of the Columbia River and a couple of miles east of the City of The Dalles. It was constructed between 1952 and 1957 by the United States Army Corps of Engineers, and was the federal government's effort to develop hydropower and navigation potential of the Columbia River after World War II.

The Dalles Dam was constructed after the Bonneville Dam in 1937 and McNary Dam in 1945. In addition to meeting the electrical power demand, a newer navigation lock would replace Corps' original and smaller Dalles-Celilo Canal.

For more history on The Dalles Dam, please visit The Dalles Dam (oregonencyclopedia.org).

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Section 1: Summary

Planning Context

The Pacific Northwest Loads and Resources Study (commonly referred to as the "White Book") is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period (operating year 2024 through 2033). The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest (PNW) region as a whole. The information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. Bonneville's Federal System Analysis calculates the Federal system load and resource balance by comparing expected Federal system loads and contract obligations to forecasted Federal system resource generation and contract purchases. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW region include variability by incorporating a variety of generation forecasts, associated with streamflows from the most recent 30-historical water conditions[1] of the 2020 Modified Flows. These deterministic analyses are modeled by operating year (OY[2]), defined as August-July, to be consistent with regional coordination of the Treaty and PNCA. Results are presented in: 1) annual and monthly energy, expressed in average megawatts (aMW); and 2) monthly peak capacity, presented in 120-Hour peak megawatts (MW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis is presented in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to more comprehensively assess the ability of the power system to meet long-term load obligations. Bonneville periodically incorporates additional studies and data into its planning that look at different analytical methods and analyze different scenarios. This year's White Book does not incorporate any other studies.

The 2023 White Book is published as a single summary document. Beginning with the 2022 White Book the Technical Appendices are no longer published along with the summary document, rather, Appendix A at the end of this summary document contains the list of reports previously included in the Technical Appendices, and those reports are available upon request. Please contact Steve Bellcoff, srbellcoff@bpa.gov, (503) 230-3319 with requests.

The total retail load, contract, and generation forecasts used in this study were updated as of December 31, 2022. The 2023 White Book supersedes the 2022 White Book.

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, and load obligation forecasts are categorized as follows: 1) Total Retail Loads (TRL), defined as each individual

[1] Additional details please refer to Climate Change and the FCRPS (including the Climate Change Resiliency effort)

[2] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2024 is August 1, 2023 through July 31, 2024.

utility's retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region (Intra-Regional Transfers *(Out)*) and outside the PNW region (Exports). Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperative, and tribal utility preference customers as stated under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches; 1) using statistical approaches that are based on time-series-based regressions that follow the fundamental assumption that historical retail electricity consumption patterns will continue into the future, 2) statistically adjusted end-use models. The statistically adjusted end-use models include calculated indexes for heating equipment, cooling equipment, and other equipment. ALF forecasts also assume normal weather conditions and do not include any explicit adjustments for the impacts of climate change, however they do use temperature normals based on recent history in order to be consistent with recent climate trends. Contract obligations not associated with Bonneville's Regional Dialogue contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of "on the ground" generating facilities and contract purchases that are used to serve retail loads. PNW resources (including the Federal system) are predominantly hydro based, therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as; 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW region (Intra-Regional Transfers *(In)*) and from outside the PNW region (Imports). The generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described below.

Hydro resources

- Regulated Hydro: Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically coordinated to meet power and non-power requirements. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydrosystem Simulator (HYDSIM) model. The HYDSIM model takes into account individual project operating characteristics and conditions, to determine energy production expected on a project-by-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.
- Independent Hydro: Independent hydro projects include those hydro projects whose generation output typically varies by water condition but are not operated as part of the coordinated Columbia River Basin system. Independent hydro generation forecasts can vary month-to-month for energy and capacity, and are developed and provided by individual project owners/operators for the same 30-historical water conditions as the Regulated Hydro projects.

- Small Hydro: Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts can vary month-to-month but are not assumed to vary by water condition.

Non-hydro renewable resources

- Wind: Firm wind generation incorporates the statistical modeling of wind generation based on historical weather data and actual generation from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as the firm wind year. The firm wind year generation performance determines each project's energy forecast. The Federal system and PNW regional capacity analyses assume zero capacity contribution from wind resources.
- Solar: Solar projects are utility scale solar facilities that are metered and the generation is being sent to the grid, and does not include any behind the meter resources. The Federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other: Other renewables include any other project identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel, and cogeneration. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced in order to account for scheduled maintenance. Forecasts are adjusted to show actual operational capabilities and expectations, and not to reflect economic dispatch.

Contract purchases

- Contract Purchases/Imports: Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publically and in data submittals. These purchases are treated as resources in both the Federal system and regional analyses. Purchases between entities within the PNW are called Intra-regional Transfers *(In)* and purchases from entities outside the PNW are called Imports. With the exception of contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms through the life of the contract and are not assumed to be renewed. Treaty power deliveries are assumed to be in place through the study period.

Adjustments to Resources

This White Book assumes that resource generation and contract purchases must be reliably delivered to load centers. To take this into account, this study makes adjustments to generation forecasts for: 1) Operating and Balancing Reserves, held to meet reliability standards; and 2) Transmission Losses, associated with power deliveries. These resource adjustments are reductions to both energy and capacity and are described below:

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing 3 percent of forecast load and 3 percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. The modeling of reserves, including those for wind integration, is described in the Hydro Resources Modeling section below. The reserve forecasts included in this 2023 White Book are modeled consistent with those used in Bonneville's BP-24 Initial Rates Proposal.

- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, usually in the form of heat, which is known as transmission losses. Transmission losses are calculated on a monthly basis and vary by generation, based on the sum of all generation and contract purchase forecasts. The transmission loss factor has several components that combine to give the estimate of losses typically associated with Federal system generation: (1) step-up transformers from generation to the high-voltage transmission network, (2) high-voltage network transmission, (3) transfers to Federal loads over non-Federal transmission systems, and (4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this Study are:
    - Energy is 3.11 percent, September through May and 3.16 percent, June through August.
    - Capacity is 3.16 percent, September through May and 3.21 percent, June through August.

Hydro Resources Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 largest federal hydroelectric projects in the mid-Columbia Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month within of the 30 year-historical streamflow[3] record (October 1989 through September 2018). Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods; ten complete months, plus two periods each for April and August. April and August are divided because natural streamflows and operations often change significantly during these months. Consequently, generation can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies encompass both power and non-power operating requirements. Each hydro study specifies particular non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The operations modeled include the following as outlined in the US Army Corps of Engineers PNCA data submittals:

- National Marine Fisheries Service 2008 Willamette BiOp (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 US Fish and Wildlife Service Biological Opinion (November 12, 2019)

The Pacific Northwest Coordination Agreement (PNCA) coordinates the planning and operation of the members' hydroelectric power projects in the PNW. PNCA project owners provide physical plant data as well as power and non-power constraints in an annual data submittal to the Western Power Pool. Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. This coordination agreement expires on September 15, 2024. PNCA project owners are currently engaging in discussions regarding PNCA expiration and future coordination.

The construction of three large storage projects in Canada under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for

[3] 2020 Modified Flows

an Assured Operating Plan (AOP) to be completed six years prior to each operating year, and allows a Detailed Operating Plan (DOP) to be completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this 2023 White Book are based on the official 2022 AOP studies, with additional modifications that reflect updates expected in the official DOP studies.

Both the United States and Canada have the ability to terminate most of the provisions of the Treaty any time after September 16, 2024, with a minimum of 10 years advance notice. Neither Canada nor the United States have provided notice of termination; therefore, this study assumes the Treaty continues throughout the study period including current flood risk management provisions.

Bonneville has other operational agreements with Canada that are not part of the Treaty. One operational agreement is the Non-Treaty Storage Agreement (NTSA) that allows additional shaping of Columbia River flows for power and fish operations by utilizing storage not specified by the Treaty from Canadian reservoirs. The NTSA allows water to be released from Canadian project storage during the spring of dry years. The NTSA also allows water to be stored in the spring during years when the spring flow targets from the 2008 NOAA BiOp would be met with a subsequent release of water in the summer. These operations have been included in this study based on the NTSA signed with British Columbia Hydro in April 2012, which expires on September 15, 2024[4].

Balancing reserves, both incremental and decremental, reduce the ability to shape Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects. In this study, the impacts of incremental reserves are shown as a reduction in the capacity analyses and are categorized as operating and balancing reserves. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

Firm Water Planning: To ensure sufficient generation to meet load, Bonneville bases its resource planning on firm water conditions or firm expected generation. Firm water conditions are defined as when the PNW hydro system would produce the least amount of power while taking into account the historical streamflow record, power and non-power operating constraints, the planned operation of non-hydro resources, and system load requirements. For operational purposes, Bonneville considers firm water conditions to be the tenth percentile of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program. For additional details, please refer to Bonneville's Climate Change Resiliency Letter to the region (June 6, 2022).

Variability of Hydro Generation: The generating capability of Federal system and regional hydro projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, any flow or operating requirements pursuant to biological opinions, and other operating limitations. Water conditions cause hydro generation to vary greatly year to year depending on factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. In addition, Federal independent hydro project generation was updated by the Army Corps of Engineers, The Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

[4] Bonneville acknowledges that there are ongoing discussions regarding the continuation of both the NTSA and the PNCA.

- Firm water: tenth percentile (P10) of system generation by month with the most recent historical 30-year streamflow conditions, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month of the most recent historical 30- year streamflow conditions, it represents the exact middle value of generation for energy and capacity.
- High water: 90th percentile (P90) of system generation by month of the most recent historical 30- year streamflow conditions, this represents the high generation scenario of the energy and capacity of the hydro system.

Generation percentile by month for each OY in the study is included in Exhibit 4-6.

Hydro Capacity Modeling: Bonneville uses the RiverWare model to forecast usable hydro capacity for long-term planning purposes. RiverWare is used to simulate the relationship of hydro energy to hydro peaking capability for Federal system regulated hydro resources. RiverWare incorporates the monthly historical 30 water year reservoir storage and flows from HYDSIM. For each month, RiverWare forecasts hourly Federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts take into account scheduled hydro maintenance and reserves.

For hydro resources, the 120-Hour capacity forecasts are created by evaluating hourly generation from RiverWare over a specific period of time. This capacity metric is defined as the average generation forecasts from the 6 highest heavy load hours per day, 5 days per week, for 4 weeks per month (6 x 5 x 4 = 120 hours). While available, the White Book does not include 1-Hour hydro capacity forecasts because it does not represent a sustainable generation but rather a single hour peak, meaning it does not consider the ability of the hydro system to sustain generation levels over a multiple hour period. January 120-hr capacity has been the most constrained metric historically, a prime example for avoiding anomalies in a single water year, January 1937 was the extreme month resulted in one percentile of the 80-water year generation distribution from the 2022 White Book. Comparisons between the 2022 White Book, which uses 1937 as firm critical condition, and this White Book, P10, will display the large difference mostly due to the anomaly of 1937 in both Federal and Regional systems.

The 120-Hour capacity analysis presented in this study better reflects the ability of the hydro system to sustain a generating peak energy level to meet load obligations throughout each month. The 120-Hour capacity presented in this analysis can be expressed as either capacity in megawatts (MW) or energy over super peak load hours in average megawatts.

Notable Updates

The 2023 White Book includes updated forecasts of Federal system power sales contract (PSC) obligations, PNW regional Total Retail Loads, contract purchases, and generation as of December 1, 2022, including:

- Updates associated with BPA's Climate Change Resiliency effort, including using the recent 30 year historical record and monthly P10 as Firm conditions.
- Three customers elected to change product elections from BPA's Slice Product to Load Following Product, and the new product election is reflected from October 1, 2024 across the study period.
- Updated retirement dates associated with planned thermal (coal) generation retirements.

Sources of Uncertainty

The forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and other factors that could significantly affect the magnitude, duration and timing of projected surpluses and/or deficits. Some of these uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations;
- Changes to hydro system operations in response to court actions and/or operational agreements;
- Natural variations in weather affecting electrical power demand and streamflow runoff that affect hydroelectric power generation;
- Potential increases or decreases in retail and industrial loads due to changes in local, regional, and/or national economic conditions;
- Potential new large individual retail loads and/or other changes to major industrial operations;
- Potential service to new loads such as new customers or the Department of Energy's Richland vitrification plant operations;
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions;
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets;
- Changes to operating limits on existing and future thermal resources;
- Changes to retirement dates associated with resources;
- Failures of resources to operate at anticipated times and/or output levels;
- Changes to Treaty obligations and/or operations;
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load;
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets;
- Future climate change impacts to retail loads, streamflows, and resources.

The potential impacts of these and other sources of uncertainty are not quantified in this report.

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Section 2: Federal System Analysis

The Federal System Analysis provides a deterministic forecast of Federal system loads and resources over a 10-year period from OY 2024 through 2033. This analysis incorporates forecasts of the Federal system's firm requirements power sales contract (PSC) obligations, contract sales and purchases, and resource generation. This section presents firm Federal system load and resource forecasts for energy and 120-Hour capacity. The detailed components of the Federal system study are available upon request.

Load Obligations

Bonneville's ALF system is used to forecast Federal system load obligations, as described previously in Section 1: Summary - Load Obligations. The types of Federal system load obligation forecasts include: 1) Federal reserve power obligations to the U.S. Bureau of Reclamation (USBR); 2) Bonneville's Regional Dialogue PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers; 3) contract obligations to investor-owned utilities (IOUs); 4) contract obligations to Direct Service Industry (DSI) customers; and 5) other Bonneville contract obligations, which include contract sales to entities within the PNW region (Intra-Regional Transfers *(Out)* and to those outside the PNW region (Exports). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather, water, or economic conditions. Bonneville's forecasts of these obligations are as follows:

USBR obligations: USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. Bonneville markets the remaining power from USBR projects in the PNW.

Regional Dialogue CHWM PSC obligations to Public & Federal agency customers: In December 2008, Bonneville executed Regional Dialogue PSCs with public, cooperative, and tribal utilities, and federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Three types of products were offered to customers: Load Following, Slice/Block, and Block. Of the 134 customers who have signed Regional Dialogue Contracts; 121 are currently Load Following customers, 10 are Slice/Block customers, and three are Block customers. Three customers: Benton PUD, Grays Harbor PUD, and Pacific PUD recently switched from Slice/ Block customers to Load Following starting in the BP24 Rate Period and are now included in this study as Load Following customers.

Under the Regional Dialogue PSCs, customers must make periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[5] load by: 1) adding new non-Federal resources; 2) acquiring power from non-Federal resources; and/or 3) requesting Bonneville to supply additional power. The current customer elections have been set through fiscal year (FY) 2025, and this study assumes that the current elections continue through the study period. Based on this assumption, Federal system Regional Dialogue PSC obligation forecasts include elected and forecasted A-RHWM load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY, which are consistent with the BP-24 Initial Rate Proposal.

[5] "A Rate High Water Mark (RHWM) defines a public customer's maximum eligibility to purchase an amount of power service at Tier 1 Rate for a Rate Period, subject to limitation by the customer's New Requirement." (P.2 Regional Dialogue June 4, 2010)

Table 2-1

Federal System
Annual Above-Rate High Water Mark (A-RHWM) Obligations
FY 2025 through 2033

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033
A-RHWM Obligations	382	408	434	460	495	516	536	549	575

IOU Load Service under Regional Dialogue PSCs: The six IOUs in the PNW region are Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. The PNW IOUs all signed Bonneville RD PSCs for FY 2011 through 2028; however, no IOUs have elected to take power service under these contracts and no net requirements power sales are assumed for the IOUs through the study period.

Direct Service Industrial (DSI) contracts: Bonneville has one DSI customer, Port Townsend Paper Corporation. Port Townsend Paper Corporation's contract with Bonneville expires on September 30, 2028. Federal system DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations: Bonneville provides federal power under a variety of additional contract arrangements. These contract obligations are categorized as 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payments for services; and 5) power commitments under the Treaty. These arrangements, collectively called "Other Contract Obligations," are determined by individual contract provisions and have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region (Intra-Regional Transfers *(Out)*) and to those outside the PNW region (Exports).

Treaty, Regional Dialogue PSC, and DSI power deliveries are assumed to remain in place through the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after expiration.

Firm Loads: The Federal system total firm load forecast shows a 2.50 percent average annual load growth over the study period. While Bonneville's forecast of PSC requirements load increases about 11 percent over the study period, Bonneville's Exports and Intra-Regional Transfers decrease due to the expiration of contracts throughout the study period. Other Contract Obligations that expire during the study period include Federal system power sales, and Federal system capacity sales. Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period. Relatively flat load growth is an expectation for the Federal system do to the nature of BPA's Regional Dialogue PSCs. While the study horizon continues past the end of Regional Dialogue contracts, and obligations are placed on BPA under the future Provider of Choice contracts is unknown at this time, the study assumes a continuation of Regional Dialogue PSC load levels for planning purposes.

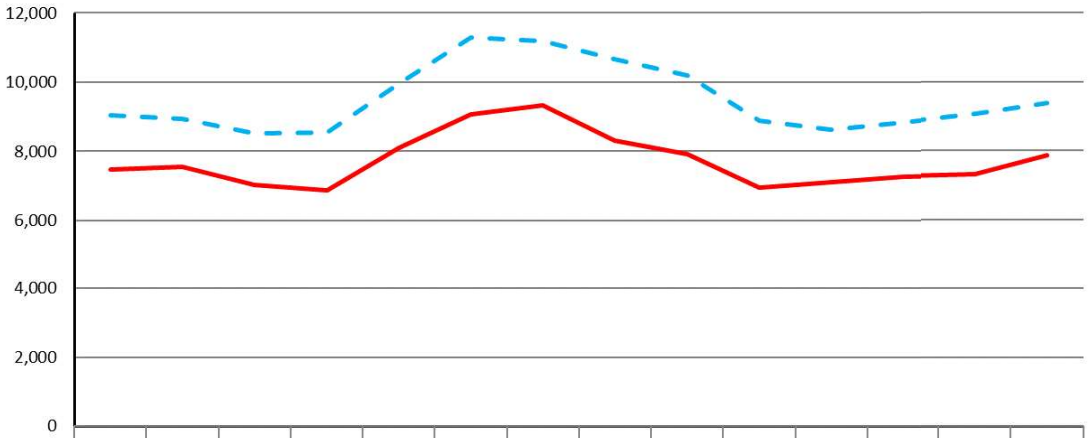
Conservation: The PSC obligation forecasts developed by ALF are expected load forecasts, which include conservation identified by individual Bonneville customers.

Bonneville loads can vary greatly throughout the year. At a high level, Bonneville forecasts represent higher loads in the winter (November through February) due to lower temperatures that increase heating loads, and lower loads during the spring, early summer and early fall when temperatures are mild. July and August loads

tend to be slightly higher than the rest of the summer due to increasing PNW air conditioning loads. Table 2-2, here, illustrates the monthly shape of the forecasted Federal system firm load obligations for OY 2024. Monthly energy and 120-Hour capacity are projected to maintain a similar shape over the study period.

Table 2-2

Federal System
Monthly Energy and 120-Hour Capacity Load Obligations
OY 2024 Firm Water Condition

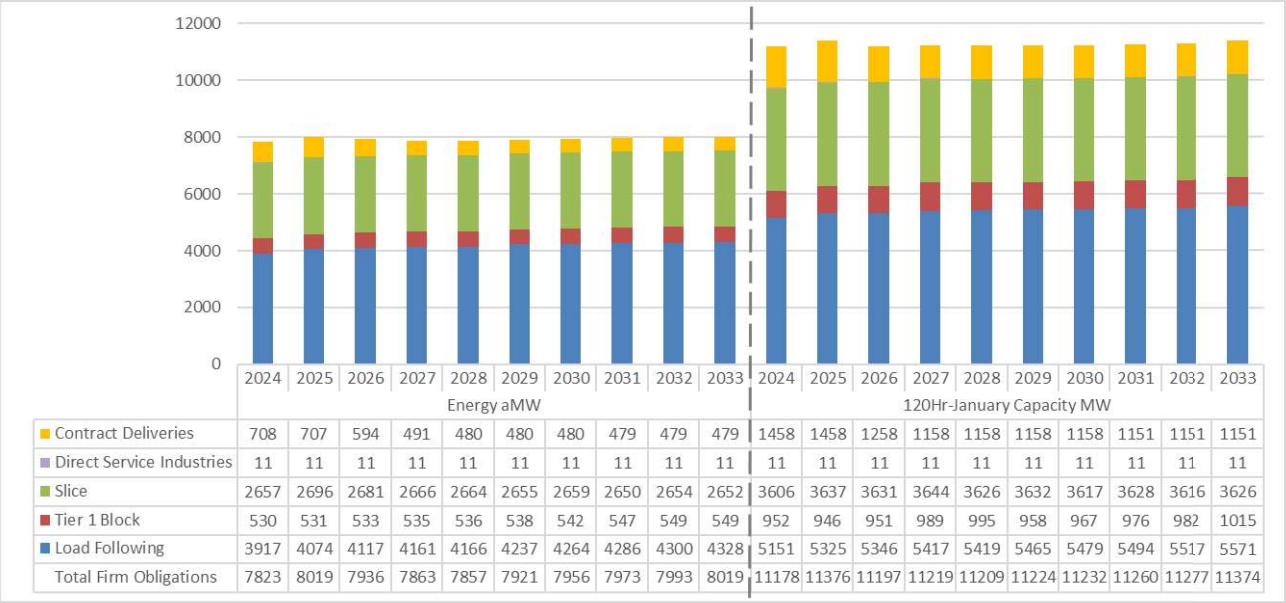


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7,467	7,564	7,022	6,877	8,095	9,057	9,338	8,321	7,912	6,955	7,106	7,267	7,314	7,862
120 Hour Cap (MW)	9,039	8,926	8,514	8,535	9,951	11,301	11,178	10,670	10,205	8,891	8,631	8,829	9,072	9,371

On an annual basis Bonneville loads vary across the study period. Table 2-3, next, illustrates the annual Federal system firm load obligations for OY2024 through 2033.

Table 2-3

Federal System
Annual Energy and 120-Hour Capacity Load Obligations
OY 2024 through 2033 Firm Water Condition
By Category



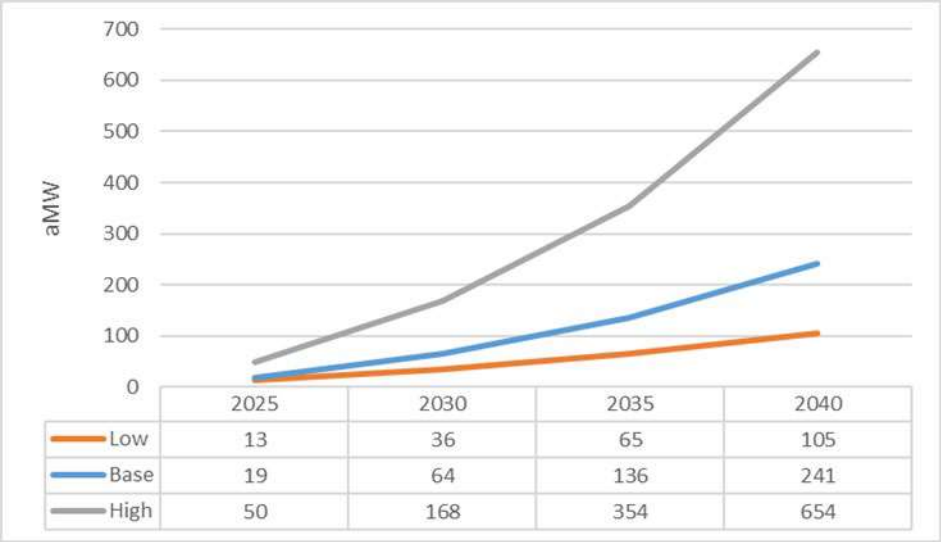
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Energy aMW										120Hr-January Capacity MW									
Contract Deliveries	708	707	594	491	480	480	480	479	479	479	1458	1458	1258	1158	1158	1158	1158	1151	1151	1151
Direct Service Industries	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Slice	2657	2696	2681	2666	2664	2655	2659	2650	2654	2652	3606	3637	3631	3644	3626	3632	3617	3628	3616	3626
Tier 1 Block	530	531	533	535	536	538	542	547	549	549	952	946	951	989	995	958	967	976	982	1015
Load Following	3917	4074	4117	4161	4166	4237	4264	4286	4300	4328	5151	5325	5346	5417	5419	5465	5479	5494	5517	5571
Total Firm Obligations	7823	8019	7936	7863	7857	7921	7956	7973	7993	8019	11178	11376	11197	11219	11209	11224	11232	11260	11277	11374

Electrification in Load Obligations

While Bonneville's contractual load forecast includes a small increase in load resulting from electrification, the growing interest in electrification suggests a potential for significant load growth in the future and an area Bonneville will continue to monitor. Table 2-4, a re-print from 2022 White Book, presents Bonneville's view of the possible range of load growth resulting from electrification in customers' load. While this study includes the base forecasted load increases from the table, a range of possible customer load increase is presented. It is important to note that due to the tiered structure of Bonneville's Regional Dialogue PSCs, only a share of increased load may become a Bonneville obligation. These possible electrification increases are expected to result from electrical vehicle use and the increasing conversion to electric applications to reduce greenhouse gases.

Table 2-4

Federal System
Annual Energy – Electrification Load Obligation Increases
(Re-print from 2022 White Book)



	2025	2030	2035	2040
Low	13	36	65	105
Base	19	64	136	241
High	50	168	354	654

Resources

In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. Bonneville does not own generating resources, rather, Bonneville markets power from Federal resources and certain non-Federal generating resources whose output Bonneville has acquired under contracts. These resources and contract purchases are collectively called "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other projects; 3) Thermal resources, which includes nuclear (Columbia Generating Station); and 4) Contract purchases, which include contract purchases from entities within the PNW region (Intra-Regional Transfers *(In)*) and from those outside the PNW region (Imports), including Non-Federal Canadian Entitlement Return power and transmission loss returns under Slice/Block contracts.

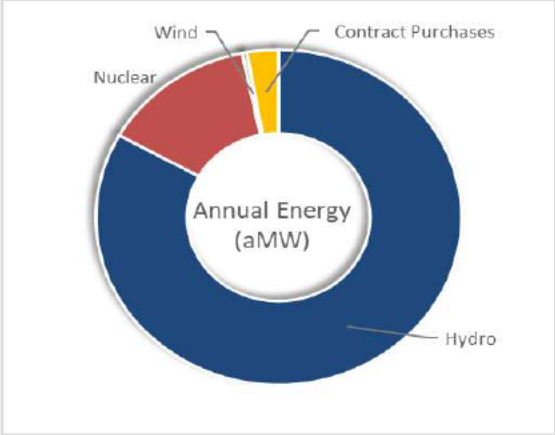
Federal System Resource Types: Table 2-5, summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY 2024, Federal system resources are forecast to produce 7,785 annual aMW of generation under Firm water conditions, with reserves and losses included.

Table 2-5 [a/]

Federal System
Generation Forecast by Resource Type
OY 2024 Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy	January 120-Hour Capacity (MW)[b/]	Percent of Capacity
Hydro	6,662	83%	11,828	88%
Nuclear	1,116	14%	1,178	9%
Wind	33	0.4%	0	0%
Other Renewables	0	0%	0	0%
Contract Purchases	227	3%	627	3%
Total Federal Resources	8,038	100%	13,633	100%

[a/] Any discrepancies in totals for figures portrayed in this table are due to rounding.
[b/] Federal resource estimates are before adjustments for reserves and transmission losses



Federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 shows the Federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally it shows the variability of individual Federal system hydro project generation for the three water conditions that represent firm, median and high water conditions.
- Federal system non-hydro resources: Federal system non-hydro resources are generating resources whose output have been purchased by Bonneville. Table 2-7 shows these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year, but may change annually based on scheduling for annual maintenance, refueling, and capital improvements.

Federal system contract purchases: Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region (Intra-Regional Transfers *(In)*) and from outside the PNW region (Imports), to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases, 2) power or energy exchange purchases, 3) power assigned to Bonneville under Treaty-related agreements, and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contracts, and these returns are also treated as Federal system resources. With the exception of deliveries from Treaty-related and Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed. Treaty-related and Slice/Block contracts are assumed to remain in place through the study horizon.

Table 2-6

Federal System
Hydro Project Generation by Various Streamflow Conditions [6]
OY 2024

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity [d/] (MW)	High [c/] Energy (aMW)	Median [c/] Energy (aMW)	Firm Energy [a/c/] (aMW)
Regulated Hydro							
1. Albeni Falls	1955	USACE	3	50	22.4	24.0	22.5
2. Bonneville [b/]	1938	USACE	18	1,221	674	535	397
3. Chief Joseph	1955	USACE	27	2,614	1,733	1,374	1,123
4. Dworshak	1974	USACE	3	465	277	203	170
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,049	2,330	1,924
	1973		6	314			
6. Hungry Horse	1952	USBR	4	310	146	94	84
7. Ice Harbor	1961	USACE	6	693	266	198	151
8. John Day	1968	USACE	16	2,480	1,328	977	762
9. Libby	1975	USACE	5	605	259	247	168
10. Little Goose	1970	USACE	6	930	278	188	151
11. Lower Granite	1975	USACE	6	930	279	186	134
12. Lower Monumental	1969	USACE	6	930	313	212	147
13. McNary	1953	USACE	14	1,120	665	556	456
14. The Dalles	1957	USACE	22	2,080	1,030	808	631
15. Total Regulated Hydro Projects *(sum lines 1 through 14)*			**169**	**21,426**	**10,319**	**7,934**	**6,320**
Independent Hydro Projects							
16. Anderson Ranch	1950	USBR	2	40	19.3	11.7	10.4
17. Big Cliff	1954	USACE	1	21	13.4	13.2	11.0
18. Black Canyon	1925	USBR	2	8.5	7.5	6.8	5.5
19. Boise Diversion	1908	USBR	3	2.5	1.5	1.2	1.0
20. Chandler	1956	USBR	2	12.2	8.4	6.8	5.3
21. Cougar	1964	USACE	2	28	16.2	16.7	15.6
22. Cowlitz Falls	1994	LCPD#1	2	70	27.8	30.4	24.2
23. Detroit	1953	USACE	2	115	43.0	47.6	33.5
24. Dexter	1955	USACE	1	17	11.4	10.1	9.5
25. Foster	1968	USACE	2	23	11.1	12.1	10.1
26. Green Peter	1967	USACE	2	92	30.7	37.6	24.7
27. Green Springs	1960	USBR	1	18	6.7	6.7	6.7
28. Hills Creek	1962	USACE	2	34	20.6	17.0	15.9
29. Lookout Point	1954	USACE	3	138	45.9	40.4	32.0
30. Lost Creek	1975	USACE	2	56	43.5	38.8	27.7
31. Minidoka	1909	USBR	4	28	38.7	29.2	24.7
32. Palisades	1957	USBR	4	177	96.9	87.4	73.1
33. Roza	1958	USBR	1	14	13.9	9.3	7.9
34. Total Independent Hydro Projects *(sum lines 16 through 33)*			**38**	**894**	**457**	**423**	**339**
Small Non-Federally Owned Hydro Projects							
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3
37. Total Non-Federally Owned Hydro Projects *(line 35 + line 36)*			**2**	**7**	**2.9**	**2.9**	**2.9**
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,778**	**8,360**	**6,662**

a/ Firm energy is the 12-month annual average for OY 2024 assuming 10th percentile (P10) water conditions
b/ Bonneville Dam generation totals include Bonneville Fishway
c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile
d/ Maximum Capacity represent full capacity of resource including overload.

[6] Streamflow conditions do not always have a linear correlation with generation. Projects with smaller head (head equals forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head (due to the increased tail water condition), this results in lower generation than in some other lower flow conditions.

Table 2-7

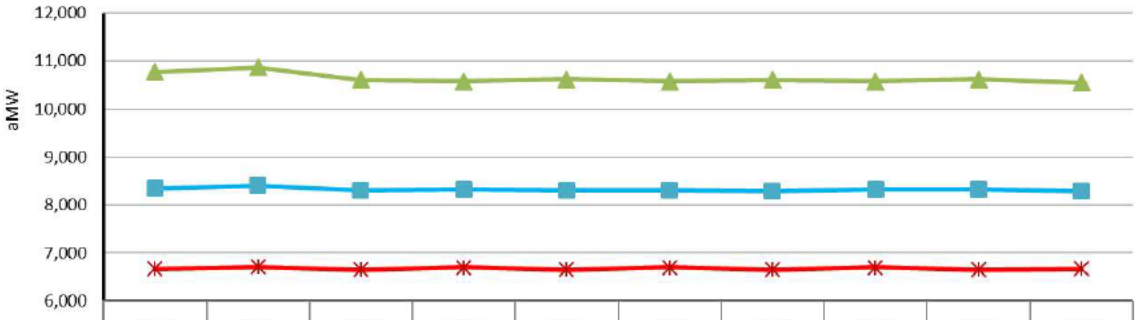
Federal System
Non-Hydro Project Generation and Contract Purchases
OY 2024

Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
Non-Hydro Resources					
1. Columbia Generating Station	1984	Nuclear	ENW	1,178	1,116
2. Condon Wind Project [b/]	2002	Wind	Condon Wind Project, LLC	0	0.0
3. Stateline Wind Project [c/]	2001	Wind	PPM, FLP	0	21.2
4. Klondike Phase III [d/]	2007	Wind	NW Wind Power	0	11.8
5. Fourmile Hill Geothermal [e/]	Not in Service	Geo.	Calpine	0	0
6. Total Federal System Non-Hydro Resources *(sum lines 1 through 5)*				**1,178**	**1,149**
Contract Purchases					
7. Canadian Entitlement for Canada (non-Federal)				235	134
8. Canadian Imports				1	1
9. Pacific Southwest Imports				0	0
10. Intra-Regional Transfers In (Pacific Northwest Purchases)				350	63
11. Slice Transmission Loss Return				41	29
12. Total Federal System Contract Purchases *(sum lines 7 through 11)*				**627**	**227**
13. Total Federal System Non-Hydro Resources and Contract Purchases *(line 6 + line 12)*				**1,805**	**1,376**

Federal System Hydro Generation Variability: The generating capability of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, and other operating limitations. Table 2-8, next, shows the annual variability of hydro generation under three streamflow conditions.

Table 2-8

Federal System
Variability of Annual Hydro Generation
OY 2024 through 2033
Under Different Water Conditions

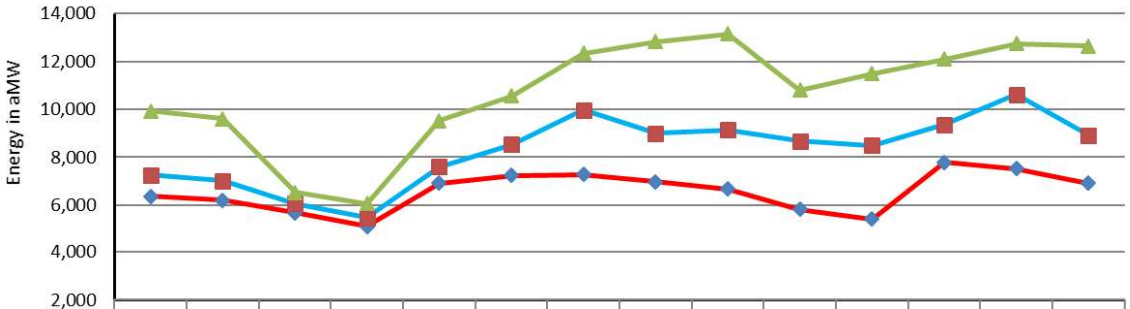


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Water (P10)	6,662	6,707	6,644	6,693	6,646	6,693	6,645	6,693	6,644	6,667
Median Water (P50)	8,360	8,403	8,308	8,328	8,307	8,316	8,285	8,323	8,334	8,300
High Water (P90)	10,778	10,866	10,607	10,582	10,614	10,582	10,608	10,582	10,613	10,550

In OY 2024, annual Federal system hydro energy generation is forecasted to be 6,662 aMW under Firm water conditions. However, under the high streamflow conditions these same Federal system hydro resources could generate 10,778 aMW. Table 2-8, above, shows the annual variability of Federal system hydro generation, and Table 2-9 shows the monthly variability of the Federal system hydro generation for OY 2024, under the same water conditions. Higher generation levels in the January through mid-April period are largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production from late-April through July is variable due to the timing and amount of the Columbia River Basin snowmelt runoff. Power production decreases through the end of the summer and early fall as streamflows are reduced due to depleted snowpack and lower precipitation levels. Annual water volume variability does not have a substantial impact on generation from the Federal system hydro resources in September and October. Hydro generation can vary by more than 6,000 aMW in a single month depending on project operations and the availability of water.

Table 2-9

Federal System
Variability of Monthly Hydro Generation
OY 2024 - Under Different Water Conditions

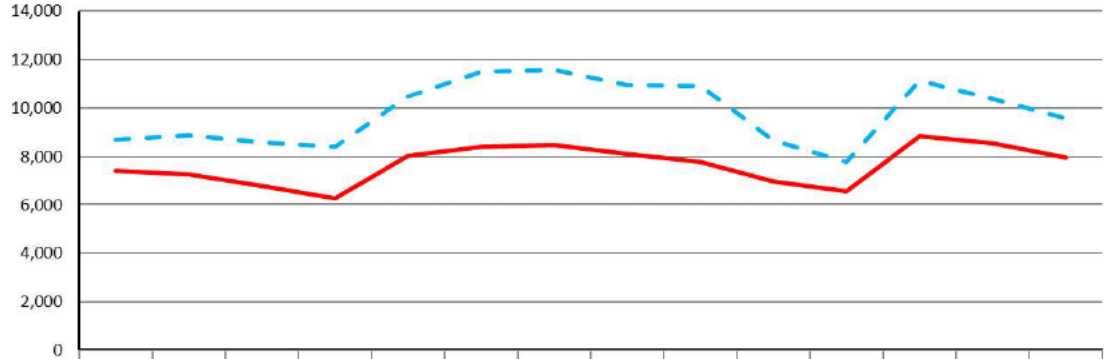


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,356	6,201	5,684	5,117	6,913	7,232	7,271	6,964	6,660	5,815	5,417	7,790	7,508	6,902
Median Water (P50)	7,251	7,008	6,052	5,472	7,600	8,535	9,960	8,991	9,144	8,677	8,492	9,353	10,608	8,910
High Water (P90)	9,938	9,597	6,521	6,069	9,515	10,565	12,340	12,833	13,149	10,796	11,494	12,086	12,741	12,646

Total Federal System Resources: Table 2-10, illustrates the monthly shape of the forecasted total Federal system generation for energy and 120-Hour capacity for OY 2024, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources and Federal system contract purchases. The Federal system maintains similar monthly shapes over the study period, with the highest generation forecasted in mid-summer, early winter, and late spring periods.

Table 2-10

Federal System
OY2024 Monthly Generation
Energy and 120-Hour Capacity
Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7,418	7,280	6,798	6,274	8,060	8,405	8,463	8,129	7,800	6,976	6,584	8,833	8,553	7,970
120 Hour Cap (MW)	8,706	8,864	8,607	8,422	10,499	11,510	11,592	10,972	10,932	8,671	7,795	11,161	10,387	9,584

Key Results

Annual Energy: Table 2-11, shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY 2024 through 2033. The Federal system monthly energy loads and resources are shown in Exhibit 4-2 for OY 2024.

Table 2-11

Federal System
Annual Energy Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424

Table 2-12 compares the 2023 White Book Federal system annual firm energy surplus/deficit results to those from the 2022 White Book. Comparing with the previous White Book, the 2023 White Book shows an increased deficit throughout the studying period except for the first year, with larger deficits in the end of the study period. These results reflect changes in both load obligations and Federal system generation.

Table 2-12

Federal System
Annual Energy Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424
2022 White Book 1937 Critical Water Conditions	-103	-245	-39	-118	-25	-164	-68	-204	-105	*n/a*
Difference ***(2023 WBK – 2022 WBK)***	86	-44	-107	-105	-134	-139	-195	-153	-198	*n/a*

120-Hour Capacity: Table 2-13 shows that the Federal system January 120-Hour capacity is mostly surplus under the firm water condition, except for the last operating year of the study period. The detailed components of the Federal system January 120-Hour capacity loads and resources for OY 2024 through 2033 are shown in Exhibit 4-3. The Federal system monthly 120-Hour capacity loads and resources are shown in Exhibit 4-4 for OY 2024.

Table 2-13

Federal System
January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	414	199	467	69	98	53	66	10	15	-123

Table 2-14 compares the 2023 White Book January firm 120-Hour capacity surplus/deficit results to those from the 2022 White Book. This study shows a large difference in January 120-Hour capacity when compared with 2022 White Book in each of the forecast OY, majority due to change from critical 1937 to P10 firm water condition analysis which affecting hydro capacity. Details previously stated in the Hydro Resources Modeling section.

Table 2-14

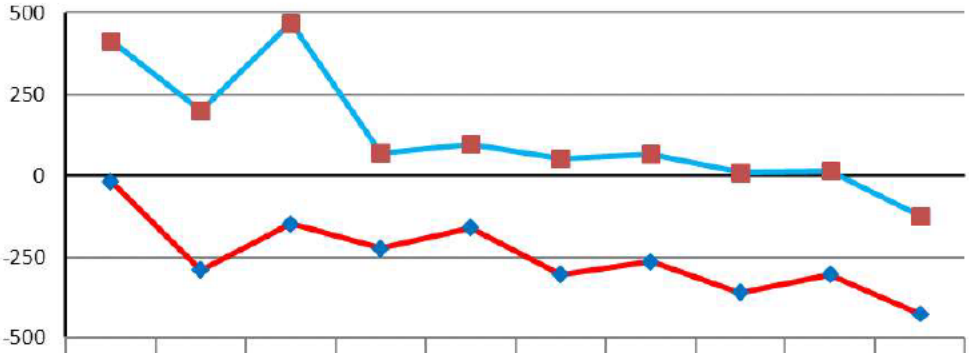
Federal System
January 120-Hour Capacity Surplus/Deficit Comparison
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	414	199	467	69	98	53	66	10	15	-123
2022 White Book 1937 Critical Water Conditions	-1,215	-1,312	-1,086	-1,263	-1,254	-1,099	-1,208	-1,163	-1,267	*n/a*
Difference *(2023 WBK – 2022 WBK)*	1629	1511	1554	1332	1351	1151	1274	1174	1282	*n/a*

Federal System Annual Surplus/Deficits: Table 2-15 graphically presents the annual firm energy and January 120-Hour capacity surplus/deficits. Over the study period, the Federal system is forecasted to have annual firm energy deficits as high as 424 aMW at the end of the study period. The January firm 120-Hour capacity forecasts show the Federal system surplus trend decreasing over the period, and eventually deficit at the last year of the study period at 123 MW. Variations in the annual energy deficits between the odd and even OYs are due to the biennial Columbia Generation Station (CGS) maintenance schedule.[7]

Table 2-15

Federal System
Annual Energy and January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (aMW)	-18	-289	-147	-223	-159	-303	-263	-357	-303	-424
January 120Hour Cap (MW)	414	199	467	69	98	53	66	10	15	-123

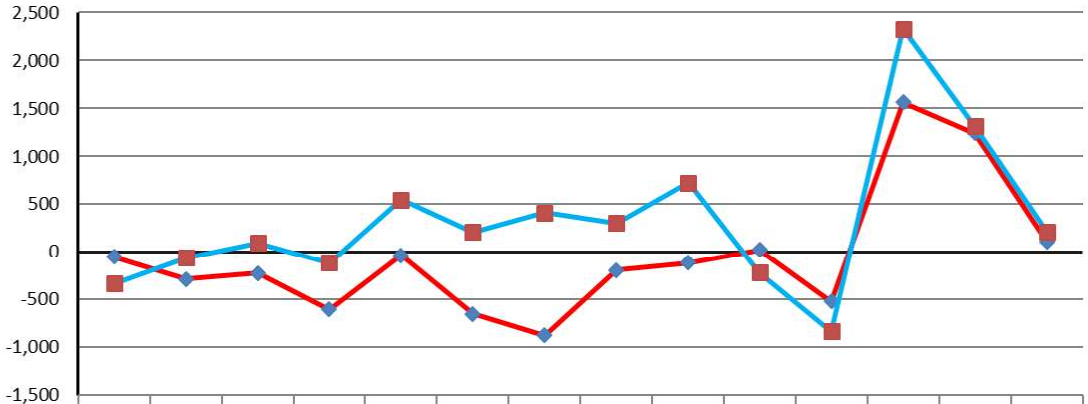
Federal System Monthly Surplus/Deficit: Table 2-16 graphically presents the Federal system monthly firm energy and 120-Hour capacity surpluses and deficits for OY 2024. Forecasts for energy and 120-Hour

[7] During even calendar years, CGS does not have scheduled maintenance and is forecast to produce 1,116 aMW annually. In odd calendar years, CGS has scheduled maintenance in May and June, and is forecasted to produce 994 aMW annually.

capacity maintain similar monthly shapes over the study period. This shows that for each month the Federal system energy and 120-Hour capacity surplus or deficit position changes during the year, with December, January, and the second half of April showing the largest monthly deficits in energy. May and June showing the largest surpluses.

Table 2-16

Federal System
Monthly Energy and 120-Hour Capacity Surplus/Deficit
OY 2024 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	-49	-284	-224	-603	-35	-652	-875	-192	-112	21	-522	1,566	1,239	108
120 Hour Cap (MW)	-333	-62	93	-113	548	209	414	302	727	-221	-836	2,332	1,315	213

Conclusion

Under Firm water conditions the Federal system shows annual firm energy deficits throughout the 2024-2033 study period. These annual energy deficits range from 18 aMW in OY 2024 to as high as 424 aMW in OY 2033. Under firm water conditions, the Federal system generally shows larger monthly energy deficits across the winter and early spring until spring runoff start, with surpluses through the spring runoff in May and across the early summer months.

The Federal system capacity analysis shows January 120-Hour capacity, under firm water condition, surplus until the last year of the study horizon on an annual basis. On a monthly basis, the study shows 120-Hour capacity largest deficits in April, caused by low water conditions in years where run-off hasn't began in until later, and surpluses though most of the year.

As water conditions improve, the Federal system surplus/deficit forecasts can vary greatly. For example, the annual energy surpluses can increase by more than 3,000 aMW under better water conditions, while the monthly surplus or deficit position can vary by more than 5,000 aMW (March). Similarly, Federal system 120-Hour capacity surpluses and deficits for OY 2024 can vary by more than 4,500 MW in the second part of April depending on water conditions.

Federal system monthly energy deficits are generally greater than the 120-Hour capacity deficits under firm water conditions. This result indicates that the Federal system is continues to be more energy constrained than capacity across the study period. The range of Federal system monthly surpluses and deficits forecasts under all 30-historical water conditions is presented in Exhibit 4-5. Additional monthly and annual details for OY 2024 through 2033 are available upon request, and a detailed list of available data is included in Appendix A.

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Section 3: Pacific Northwest Regional Analysis

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2024 through 2033. Firm load and resource forecasts are made for both energy and 120-Hour capacity based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resource forecasts incorporate annual regional utility data submittals received by Bonneville.

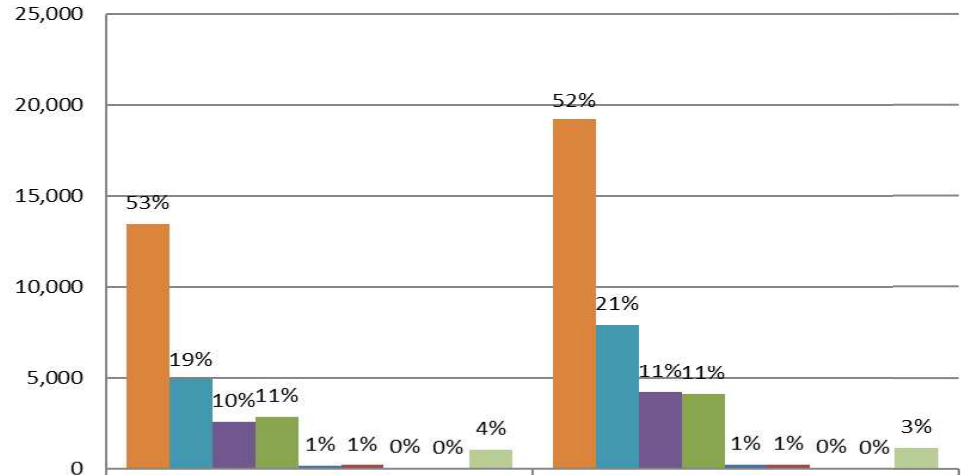
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historic conservation savings, and do not include specific adjustments for future climate change impacts. With the exception of power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration. Treaty power deliveries are assumed to be in place through the study period. The sum of the forecasted TRL and Export contracts represent the regional loads for the PNW. Regional loads are comprised of about 96 percent retail loads and 4 percent exports.

Table 3-1 shows the forecasted composition of PNW regional load for OY 2024. For the PNW region.

Table 3-1

PNW Region
Firm Regional Loads by Customer Class
OY 2024



	Energy (aMW)	January 120-Hour Capacity (MW)
Investor-Owned Utility	13,455	19,202
Public Utility District	4,901	7,940
Municipality	2,562	4,226
Cooperative	2,854	4,113
Federal Agency	148	232
USBR	188	201
DSI 1/	53	65
Marketer	3	3
Exports	1,019	1,143

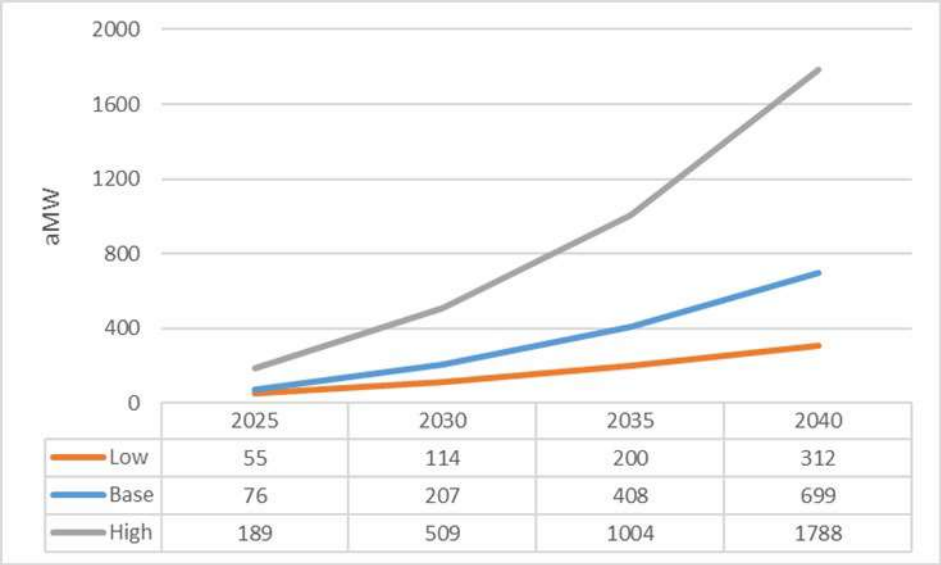
[1] Direct-Service Industry (DSI) loads include regional loads currently served by Bonneville through DSI service contracts and former DSIs served by other energy suppliers.

Electrification in Regional Loads

The regional load forecast includes some electrification, however the growing interest in electrification signals a potential for significant load growth in the future. Table 3-2, a re-print from the 2022 White Book, presents Bonneville's view of the wide possible range of electrification load increases to regional loads. While this study includes the base forecasted load increases from the table related to electrification, the table shows the range of possible load increase from electrification, with possible electrification load increases on a scale of 2.5 times the base forecast in 2030. Load increases due to electrification are expected to result from electrical vehicle use and the increasing conversion to electric applications to reduce greenhouse gases.

Table 3-2

PNW Region
Annual Energy – Electrification Load Obligation Increases
(Re-print from 2022 White Book)



	2025	2030	2035	2040
Low	55	114	200	312
Base	76	207	408	699
High	189	509	1004	1788

Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Like the Federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases, which are identified as Imports.

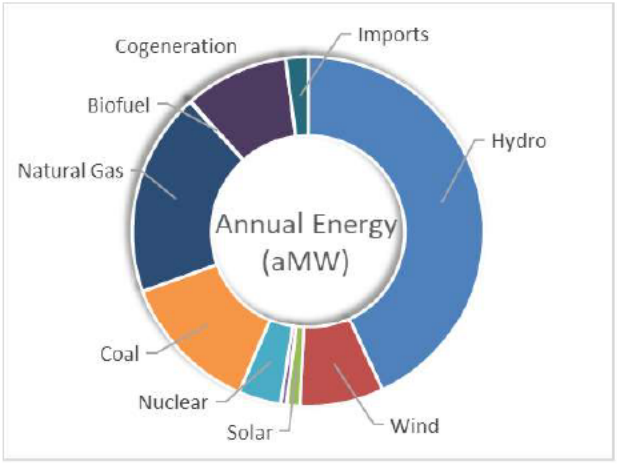
Table 3-3, next, summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the date of the announced retirement. Regional resource forecasts assume the retirement of the following coal projects over the study period: Centralia 2 (December 1, 2025) and Valmy 2 (January 1, 2026). Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

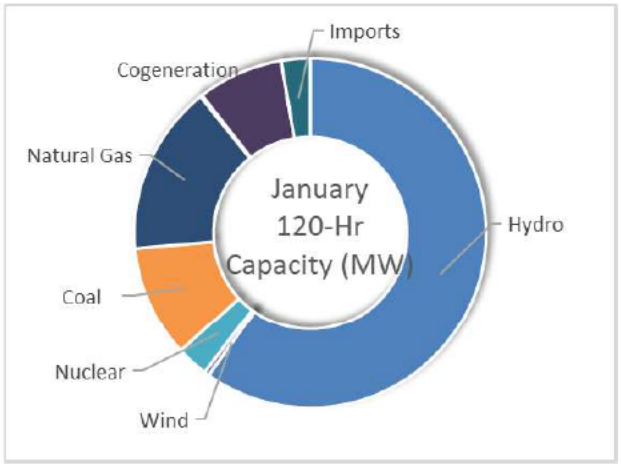
Table 3-3 [a/]

PNW Region
Generation by Resource Type
OY 2024 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy	January 120-Hour Capacity (MW)	Percent of Capacity
Hydro	12,081	43%	24,046	60%
Wind	2,200	8%	0	0%
Solar	352	1.2%	0	0%
Other Renewable	159	0.6%	182	0.5%
Nuclear	1,116	4%	1,178	3%
Coal	3,751	13%	4,195	10%
Natural Gas	5,373	19%	6,288	16%
Petroleum	0	0%	39	0.1%
Biofuel	26	0.1%	31	0.1%
Cogeneration	2,737	10%	3,179	8%
Imports	588	2%	1,065	3%
Total Regional Resources	**28,382**	**100%**	**40,202**	**100%**

[a/] Any discrepancies in totals for figures portrayed in this table are due to rounding.





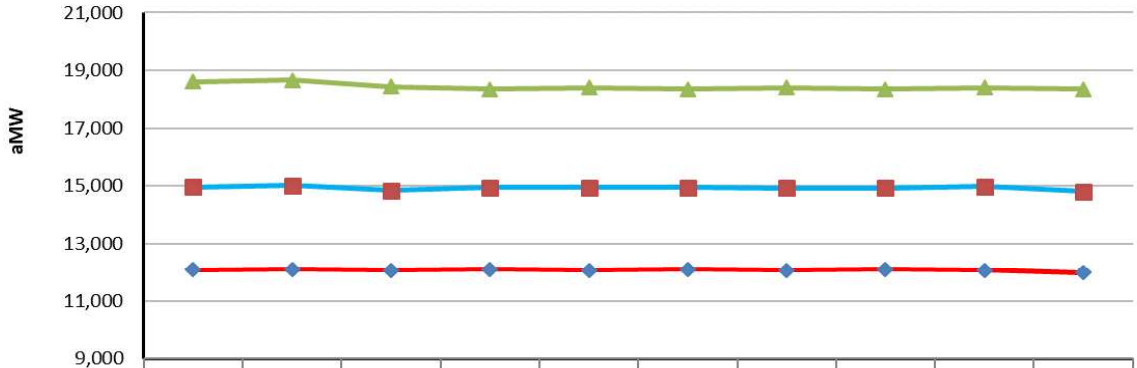
Regional Hydro Generation Variability: The generating capability of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to the federal hydro resources, Bonneville utilizes the 30-year streamflow record and percentile of T1SFCO results for planning purposes. To simplify the presentation of hydro generation variability, this study uses three water conditions to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three generation scenarios, details please refer to Hydro Resources Modeling section.

In OY 2024, annual Firm energy generation from regional hydro projects is forecasted to be 12,081 aMW under the firm water condition. This represents about 43 percent of region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW depending on water conditions.

Table 3-4

PNW Region
Variability of Annual Hydro Generation
OY 2024 through 2033
Under Different Water Conditions

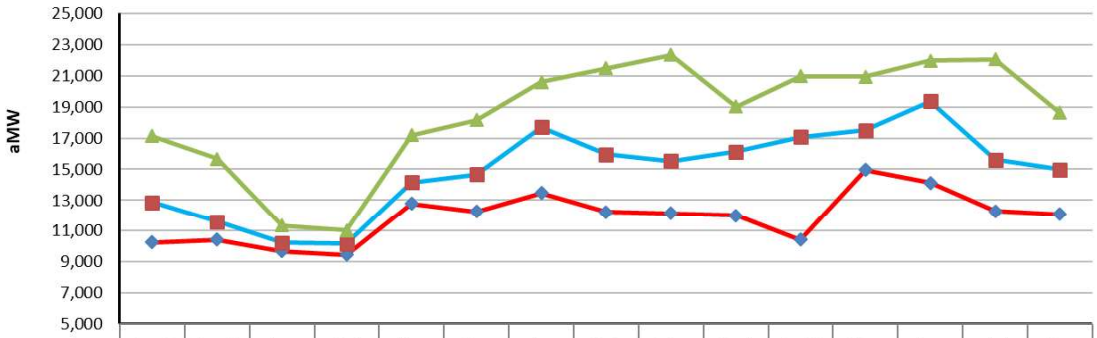


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Water (P10)	12,081	12,110	12,061	12,099	12,062	12,099	12,062	12,099	12,061	11,981
Median Water (P50)	14,970	15,020	14,845	14,952	14,942	14,944	14,936	14,928	14,991	14,816
High Water (P90)	18,617	18,662	18,442	18,356	18,408	18,356	18,400	18,356	18,407	18,356

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2024. High generation levels in the January through March period is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production in late-April through July is variable due to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of the summer and early fall as streamflows are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from August through November. Regional hydro generation capability can vary by as much as 10,000 aMW in a month, depending on the availability of water.

Table 3-5

PNW Region
Variability of Monthly Hydro Generation
OY 2024 under Different Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,268	10,424	9,680	9,468	12,772	12,264	13,459	12,220	12,157	12,010	10,436	14,953	14,121	12,294	12,081
Median Water (P50)	12,868	11,591	10,237	10,180	14,150	14,681	17,712	15,952	15,523	16,130	17,067	17,499	19,372	15,600	14,970
High Water (P90)	17,128	15,680	11,353	11,036	17,178	18,161	20,582	21,478	22,334	19,026	20,956	20,936	21,970	22,056	18,617

Variability Due to IPP Generation Delivered to the PNW Region: The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources, that are not committed to serving specific loads represent approximately 2,790 aMW of energy with an associated 3,172 MW of January 120-Hour capacity in OY 2024. The inclusion of this uncommitted IPP generation is reasonable from a long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demand. Table 3-6, below, details the region's total uncommitted IPP annual energy and January 120-Hour capacity generation forecasts over the OY 2024 through 2033 study period. Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect these changes.

Table 3-6

PNW Region
Uncommitted Independent Power Producer Generation
Annual Energy and January 120-Hour Capacity
OY 2024 through 2033

Regional Uncommitted IPP	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual Energy (aMW)	2,790	2,796	2,622	2,552	2,581	2,592	2,587	2,591	2,586	2,596
January 120-Hour Capacity (MW)	3,172	3,172	2,881	2,881	2,881	2,881	2,881	2,881	2,881	2,881

Table 3-7

PNW Region
Uncommitted Independent Power Producer Projects
OY 2024 Firm Water Condition

Project	Fuel Type	Energy (aMW)	Peak (MW)
Airport Solar	Solar	13	0
Centralia Complex [a/b/]	Coal	260	290
Condon Wind	Wind	12	0
Cosmopolis Specialty Fibres	Wood Waste	14	14
Hermiston Power Project	Wood Waste	567	630
International Paper Energy Center	Wood Waste	17	22
Juniper Canyon Wind	Wind	36	0
Kittitas Valley Wind	Wind	24	0
Klamath Generation Facility	Natural Gas	436	484
Klamath Generation Peakings (CT)	Natural Gas	90	100
Klondike Wind 1	Wind	6	0
Klondike Wind 3	Wind	23	0
Klondike Wind 3a	Wind	18	0
Leaning Juniper Wind	Wind	47	0
Longview Fibre Paper & Packaging	Wood Waste	35	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	0	0
Pelton	Hydro	14	41
Priest Rapids	Hydro	85	154
Rock Island	Hydro	169	154
Rocky Reach	Hydro	157	339
Round Butte	Hydro	30	99
Satsop Combustion Turbine Project	Natural Gas	584	650
SDS Lumber	Wood Waste	1	1
Smith Creek (Idaho)	Hydro	7	0
Stateline Wind	Wind	8	0
Tacoma Biomass (WestRock)	Wood Waste	44	55
Tieton Dam (Yakima)	Hydro	0	0
Vansycle Wind	Wind	23	0
Wanapum	Hydro	25	60
Weyerhaeuser Longview	Wood Waste	35	44
Willow Creek Wind	Wind	16	0
Total Uncommitted IPP Generation		2,796	3,172

[a/] Centralia #1 (670 MW) retired Dec 1, 2020
[b/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025

Key Results

Annual Energy: Table 3-8 shows annual energy surpluses for the PNW region throughout the study period under Firm water conditions. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,316 aMW in OY 2024) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY 2024 through 2033 are shown in Exhibit 5-1. OY2024 Monthly PNW regional energy loads and details are shown in Exhibit 5-2. Further details of each component for OY 2024 through 2033 are available upon request.

Table 3-8

PNW Region
Annual Energy Surplus/Deficit
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	2,316	1,905	1,357	932	728	509	553	40	144	-61

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

Table 3-9

PNW Region
Variability of Annual Energy Surplus/Deficit
Assuming Different Levels of Uncommitted IPP Generation
OY 2024 through 2033
Firm Water Conditions

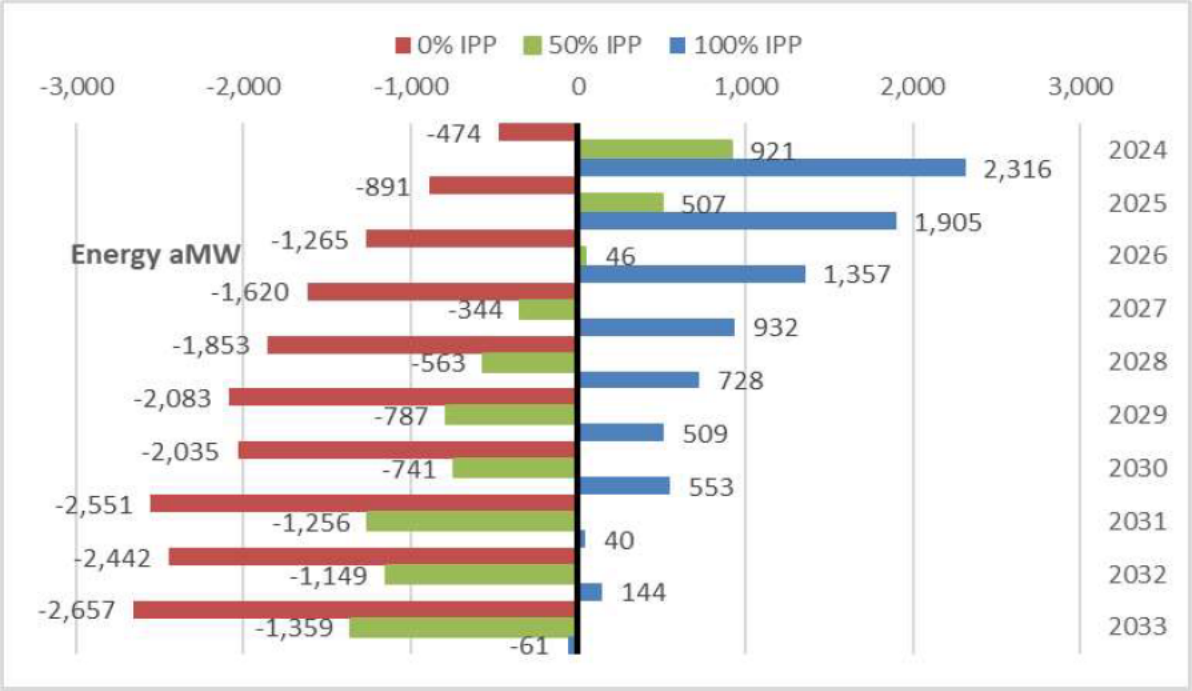


Table 3-10 compares the 2023 White Book PNW regional annual firm energy surplus or deficit forecasts to the 2022 White Book results. The PNW region continues to have annual energy surpluses throughout most of the study period. Comparing to the 2022 White Book, the difference is mainly driven by increased regional resources such as several wind projects coming on-line and hydro generations increase due to change of Firm water conditions.

Table 3-10

PNW Region
Annual Energy Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

Energy (aMW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	2,316	1,905	1,357	932	728	509	553	40	144	-61
2022 White Book 1937 Critical Water Conditions	2277	1810	1180	646	394	43	47	-543	-440	n/a
Difference ***(2023 WBK – 2022 WBK)***	*38*	*96*	*176*	*286*	*334*	*466*	*506*	*583*	*584*	*n/a*

January 120-Hour Capacity: Table 3-11 shows the January firm 120-Hour capacity surpluses and deficits for the PNW region. The region is forecasted to have January 120-Hour capacity deficits over most of the study period. This assumes that 100 percent of PNW uncommitted IPP generation is available to serve regional loads. The individual components of the PNW regional January 120-Hour capacity loads and resources for OY 2024 through 2033 are shown in Exhibit 5-3, and OY2024 monthly PNW regional 120-Hour capacity loads and resources are in Exhibit 5-4.

Table 3-11

PNW Region
January 120-Hour Capacity Surplus/Deficit
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Surplus/Deficit	449	155	-794	-1,438	-1,351	-1,940	-1,745	-3,254	-2,971	-3,506

Table 3-12 shows the significant variability in PNW regional January firm 120-Hour capacity surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

Table 3-12

PNW Region
Variability of January 120-Hour Capacity Surplus/Deficit
Assuming Different Levels of Uncommitted IPP Generation
OY 2024 through 2033 Firm Water Conditions

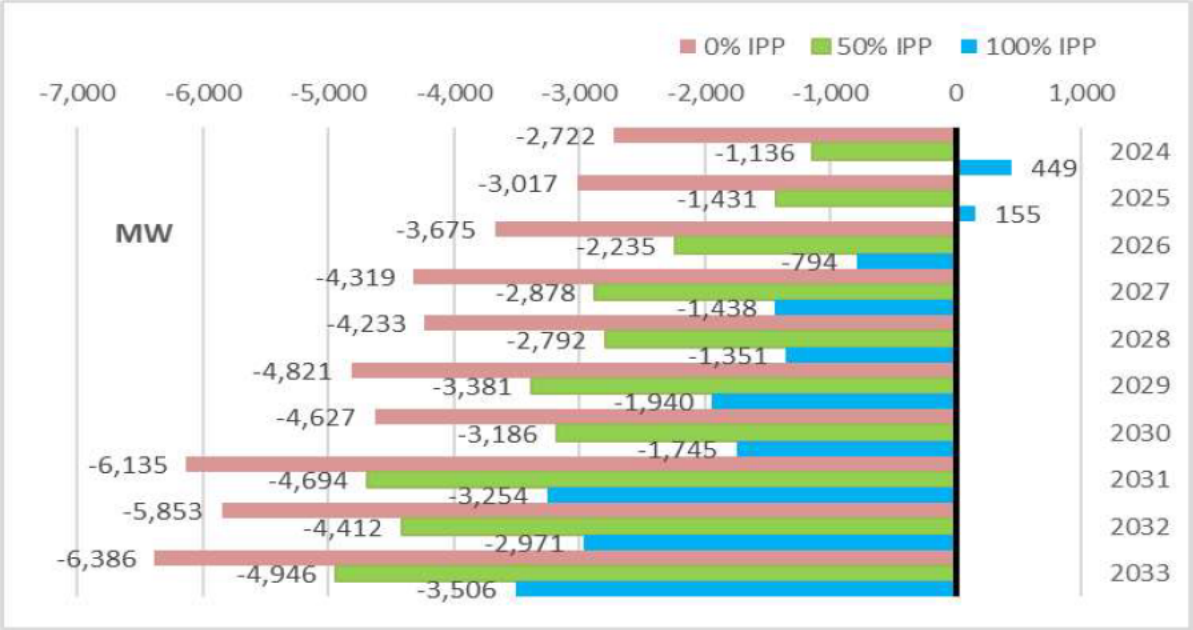


Table 3-13 compares the 2023 White Book January firm 120-Hour capacity forecast to the 2022 White Book results. Regional January 120-Hour capacity surplus/deficits show smaller deficits over the study period. The difference in January 120-Hour capacity deficits, compared to the 2022 White Book, are mainly driven by change from critical 1937 to P10 firm water condition analysis which resulted in increased hydro capacity output. Details stated in Hydro Resources Modeling section.

Table 3-13

PNW Region
January 120-Hour Capacity Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2024 through 2033
Firm Water Conditions

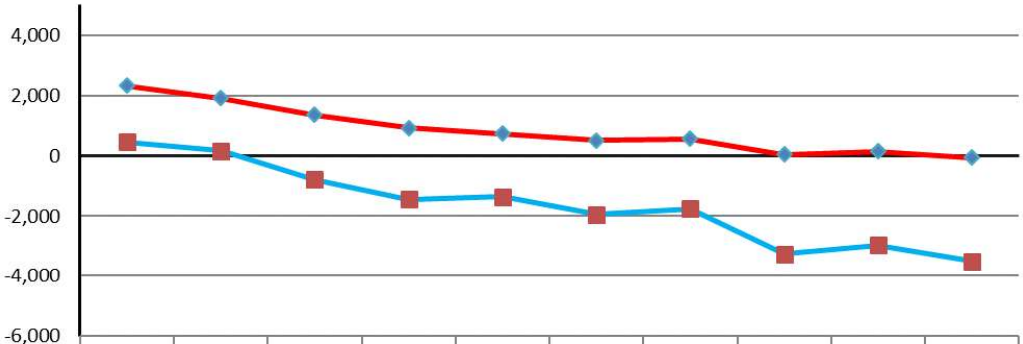
January 120-Hour Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
2023 White Book P10 generation	449	155	-794	-1438	-1351	-1940	-1745	-3254	-2971	-3506
2022 White Book 1937 Critical Water Conditions	-767	-1,069	-2,173	-2,524	-2,846	-2,936	-3,298	-4,300	-4,506	n/a
Difference *(2023 WBK – 2022 WBK)*	1217	1224	1379	1086	1495	996	1553	1046	1535	n/a

Regional Annual Surplus/Deficit: Table 3-14 graphically presents the annual firm energy and January 120-Hour capacity surplus and deficit forecasts for the PNW Region. These forecasts assume 100 percent availability of the PNW's uncommitted IPP generation to serve regional loads. The regional annual energy and January 120-Hour capacity surplus and deficit declines over the 10-year study period. By the end of the period, the study

shows an annual energy deficit of 61 aMW, while January 120-Hour capacity is deficit over most of the study period ending with a deficit of 3,506 MW. Continuing declines in the surplus and deficit position over the study period, for both annual energy and January 120-Hour capacity, are driven by a combination of annual load growth, and the reduction of resources across the region.

Table 3-14

PNW Region
Annual Energy and January 120-Hour Capacity Surplus/Deficit
OY 2024 through 2033
Firm Water Conditions

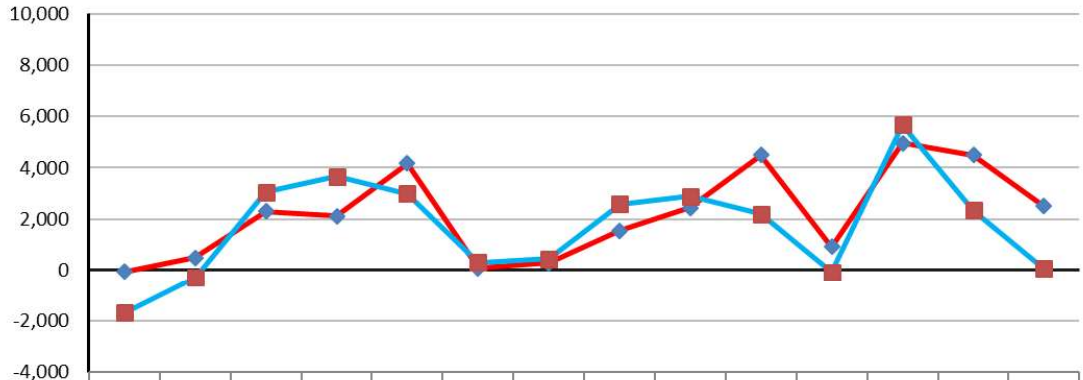


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (aMW)	2,316	1,905	1,357	932	728	509	553	40	144	-61
January 120 Hour Cap (MW)	449	155	-794	-1,438	-1,351	-1,940	-1,745	-3,254	-2,971	-3,506

Regional Monthly Surplus/Deficit: Table 3-15 graphically presents the monthly energy and 120-Hour capacity surplus or deficit forecasts for OY 2024. These forecasts assume 100 percent availability of the PNW's uncommitted IPP generation to serve regional loads. This monthly view shows the variability that the region experiences during the year, with December and January showing a deficit and the late spring showing the largest surpluses. Forecasts for monthly energy and 120-Hour capacity maintain similar shaping over the study period.

Table 3-15

PNW Region
Monthly Energy and 120-Hour Capacity Surplus/Deficit
OY 2024 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	-66	494	2,310	2,113	4,179	83	297	1,543	2,444	4,503	924	4,966	4,507	2,502
120-Hour Cap (MW)	-1,683	-300	3,053	3,666	2,995	304	449	2,587	2,886	2,205	-66	5,672	2,346	70

Conclusion

The PNW region is projected to have annual firm energy surpluses throughout most of the study period and a slight deficit in the last year, assuming modest load growth and 100 percent of the PNW region's uncommitted IPP generation is available to the region. However, using the same assumptions, the PNW region is forecast to be deficit in January firm 120-Hour capacity through most of the latter study periods, with surplus in the first two years. This study further shows that the PNW region is firm 120-Hour capacity constrained on a monthly basis. Since this analysis assumes that PNW uncommitted IPP generation is used to serve PNW regional load, the supply of power within the region can change dramatically if uncommitted IPP generation is committed to serve loads outside the PNW, or if committed resources retire early or unexpectedly. The surplus and deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-5. Additional monthly and annual details for OY 2024 through 2033 are available upon request, and a detailed list can be found in Appendix A.

The regional energy and capacity deficits identified in this analysis may be mitigated through resource options discussed in the NWPCC's 2021 Northwest Power Plan. Bonneville provides this PNW regional planning analysis for informational purposes only.

Section 4: Federal System Analysis Exhibits

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Federal System Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024-2033 Water Year: P10
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230315-141333

	Energy-aMW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Firm Obligations										
1	**Load Following**	3917	4074	4117	4161	4166	4237	4264	4286	4300	4328
2	Preference Customers	3591	3738	3775	3816	3820	3887	3913	3935	3949	3976
3	Federal Agencies	138	148	154	157	159	162	162	163	163	164
4	USBR	188	188	188	188	188	188	188	188	188	188
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	530	531	533	535	536	538	542	547	549	549
7	Tier 1 Block	530	531	533	535	536	538	542	547	549	549
8	**Slice**	2637	2672	2661	2644	2639	2633	2635	2628	2629	2623
9	Slice Block	1236	1259	1250	1259	1242	1250	1238	1245	1232	1245
10	Slice Output from T1 System	1400	1413	1411	1385	1397	1383	1397	1383	1397	1378
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	708	707	594	491	480	480	480	479	479	479
14	Exports	465	468	471	468	469	469	469	469	469	469
15	Intra-Regional Transfers (Out)	243	239	123	22	11	11	11	9	9	9
16	**Total Firm Obligations**	**7803**	**7996**	**7915**	**7841**	**7833**	**7899**	**7931**	**7952**	**7969**	**7990**
	Net Resources										
17	**Hydro**	6662	6707	6644	6693	6646	6693	6645	6693	6644	6667
18	Regulated Hydro - Net	6320	6358	6304	6343	6306	6343	6305	6343	6306	6365
19	Independent Hydro - Net	339	345	337	347	337	347	337	347	335	299
20	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88
21	**Non-Hydro Renewable**	33.0	33.0	33.0	19.8	1.9	0.0	0.0	0.0	0.0	0.0
22	Wind - Net	33.0	33.0	33.0	19.8	1.9	0.0	0.0	0.0	0.0	0.0
23	Solar - Net	0	0	0	0	0	0	0	0	0	0
24	Other - Net	0	0	0	0	0	0	0	0	0	0
25	**Thermal**	1116	994	1116	994	1116	994	1116	994	1116	994
26	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
27	Coal - Net	0	0	0	0	0	0	0	0	0	0
28	Natural Gas - Net	0	0	0	0	0	0	0	0	0	0
29	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
30	Biofuel - Net	0	0	0	0	0	0	0	0	0	0
31	Cogeneration - Net	0	0	0	0	0	0	0	0	0	0
32	**Contract Purchases**	227	227	228	165	165	165	165	165	165	164
33	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34	Intra-Regional Transfers (In)	63.1	63.0	63.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Non-Federal CER	134	134	135	135	135	135	135	135	135	135
36	Slice Transmission Loss Return	28.5	28.7	28.7	28.3	28.6	28.3	28.6	28.3	28.6	28.2
37	**Reserves & Losses**	-253	-253	-253	-253	-255	-256	-257	-257	-259	-258
38	Operating Reserves	0	0	0	0	0	0	0	0	0	0
39	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
40	Transmission Losses	-253	-253	-253	-253	-255	-256	-257	-257	-259	-258
41	**Total Net Resources**	**7785**	**7707**	**7769**	**7619**	**7674**	**7596**	**7669**	**7594**	**7666**	**7566**
42	**Total Surplus/Deficit**	**-18**	**-289**	**-147**	**-223**	**-159**	**-303**	**-263**	**-357**	**-303**	**-424**

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Federal System Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

2024	360	384	720	744	720	744	744	696	744	360	360	744	720	744	8784
Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Obligations															
1 **Load Following**	3900	3902	3415	3431	3736	4493	4498	4136	3787	3695	3695	3695	3972	4236	3917
2 Preference Customers	3454	3456	3025	3180	3578	4313	4322	3945	3576	3330	3330	3230	3457	3674	3591
3 Federal Agencies	116	117	104	129	149	169	167	172	150	131	131	120	120	135	138
4 USBR	330	329	286	123	9.67	10.8	8.39	18.0	61.0	234	234	345	395	427	188
5 Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 **Tier 1 Block**	342	342	562	488	808	808	891	810	793	386	386	139	21.3	316	530
7 Tier 1 Block	342	342	562	488	808	808	891	810	793	386	386	139	21.3	316	530
8 **Slice**	2439	2448	2317	2256	2844	3050	3243	2668	2629	2170	2321	2730	2619	2579	2637
9 Slice Block	1133	1133	1116	1136	1322	1510	1494	1331	1276	1178	1178	1133	1084	1120	1236
10 Slice Output from T1 System	1306	1315	1201	1120	1522	1540	1749	1337	1353	992	1143	1597	1535	1459	1400
11 **Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11 0	11.0	11.0	11.0	11.0	11.0	11.0
12 Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13 **Contract Deliveries**	775	861	717	692	695	694	696	697	692	693	693	692	692	720	708
14 Exports	512	598	454	454	454	454	454	454	454	454	454	454	454	483	465
15 Intra-Regional Transfers (Out)	263	264	262	237	241	240	241	242	237	238	238	237	237	237	243
16 **Total Firm Obligations**	**7467**	**7564**	**7022**	**6877**	**8095**	**9057**	**9338**	**8321**	**7912**	**6955**	**7106**	**7267**	**7314**	**7862**	**7803**
Net Resources															
17 **Hydro**	6356	6201	5684	5117	6913	7232	7271	6964	6660	5815	5417	7790	7508	6902	6662
18 Regulated Hydro - Net	6051	5800	5447	4842	6478	6921	6852	6747	6404	5528	5030	7407	7050	6488	6320
19 Independent Hydro - Net	303	398	234	273	433	307	416	213	252	283	383	380	455	412	339
20 Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.04	3.10	3.09	3.09	2.83	2.72	2.63	2.88
21 **Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33.0
22 Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33.0
23 Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 **Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
26 Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
27 Coal - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Natural Gas - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Biofuel - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Cogeneration - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 **Contract Purchases**	167	168	185	218	255	300	335	287	248	220	223	168	167	170	227
33 Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1 00	1.00	1.00	1.00	1.00	1.00	1.00
34 Intra-Regional Transfers (In)	0	0	25.0	64.0	88.9	138	164	125	89.0	64.4	64.4	0	0	0	63.1
35 Non-Federal CER	136	137	136	131	136	131	136	135	132	136	136	136	131	136	134
36 Slice Transmission Loss Return	30.0	30.2	23.3	21.7	29.6	29.9	33.9	26.0	26.3	19.3	22.2	31.0	35.3	33.5	28.5
37 **Reserves & Losses**	-244	-239	-219	-203	-260	-271	-273	-262	-252	-225	-214	-286	-282	-262	-253
38 Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39 Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40 Transmission Losses	-244	-239	-219	-203	-260	-271	-273	-262	-252	-225	-214	-286	-282	-262	-253
41 **Total Net Resources**	**7418**	**7280**	**6798**	**6274**	**8060**	**8405**	**8463**	**8129**	**7800**	**6976**	**6584**	**8833**	**8553**	**7970**	**7785**
42 **Total Surplus/Deficit**	**-49**	**-284**	**-224**	**-603**	**-35**	**-652**	**-875**	**-192**	**-112**	**21**	**-522**	**1,566**	**1,239**	**108**	**-18**

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Exhibit 4-3: Annual 120-Hour January Capacity

Federal System Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024-2033 Water Year: P10 January
2023 White Book - 30WY Report Date: **12/5/2022**

S241-WB-20230315-141333

	120Hr-MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Firm Obligations	2002	2002	2002	2001	2002	2001	2002	2001	2002	2001
1	**Load Following**	5151	5325	5346	5417	5419	5465	5479	5494	5517	5571
2	Preference Customers	6182	6354	6372	6443	6442	6525	6534	6542	6572	6602
3	Federal Agencies	224	233	238	240	244	248	248	249	249	250
4	USBR	201	201	201	201	201	201	201	201	201	201
5	Federal Diversity	-1456	-1462	-1465	-1467	-1468	-1509	-1504	-1498	-1505	-1482
6	**Tier 1 Block**	952	946	951	989	995	958	967	976	982	1015
7	Tier 1 Block	952	946	951	989	995	958	967	976	982	1015
8	**Slice**	3606	3637	3631	3644	3626	3632	3617	3628	3616	3626
9	Slice Block	1494	1525	1505	1522	1500	1511	1491	1505	1489	1506
10	Slice Output from T1 System	2112	2112	2126	2121	2126	2121	2126	2123	2127	2120
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	1458	1458	1258	1158	1158	1158	1158	1151	1151	1151
14	Exports	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142
15	Intra-Regional Transfers (Out)	316	316	116	16.4	16.4	16.4	16.4	9.44	9.44	9.44
16	**Total Firm Obligations**	**11178**	**11376**	**11197**	**11219**	**11209**	**11224**	**11232**	**11260**	**11277**	**11374**
	Net Resources										
17	**Hydro**	11828	11828	11899	11876	11899	11876	11899	11876	11899	11861
18	Regulated Hydro - Net	11287	11287	11358	11602	11358	11602	11358	11602	11358	11602
19	Independent Hydro - Net	536	536	536	269	536	269	536	269	536	254
20	Small Hydro - Net	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59
21	**Non-Hydro Renewable**	0	0	0	0	0	0	0	0	0	0
22	Wind - Net	0	0	0	0	0	0	0	0	0	0
23	Solar - Net	0	0	0	0	0	0	0	0	0	0
24	Other - Net	0	0	0	0	0	0	0	0	0	0
25	**Thermal**	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
26	Nuclear - Net	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
27	Coal - Net	0	0	0	0	0	0	0	0	0	0
28	Natural Gas - Net	0	0	0	0	0	0	0	0	0	0
29	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
30	Biofuel - Net	0	0	0	0	0	0	0	0	0	0
31	Cogeneration - Net	0	0	0	0	0	0	0	0	0	0
32	**Contract Purchases**	627	627	631	281	281	281	281	281	281	281
33	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34	Intra-Regional Transfers (In)	350	350	350	0	0	0	0	0	0	0
35	Non-Federal CER	235	235	237	237	237	237	237	237	237	237
36	Slice Transmission Loss Return	41.0	41.0	43.2	43.1	43.2	43.1	43.2	43.1	43.2	43.1
37	**Reserves & Losses**	-2042	-2057	-2043	-2047	-2052	-2059	-2061	-2065	-2066	-2070
38	Operating Reserves	-790	-795	-780	-785	-790	-793	-797	-798	-801	-802
39	Balancing Reserves	-878	-886	-886	-886	-886	-886	-886	-886	-886	-886
40	Transmission Losses	-374	-376	-377	-376	-375	-379	-378	-381	-379	-382
41	**Total Net Resources**	**11592**	**11576**	**11665**	**11288**	**11306**	**11277**	**11297**	**11270**	**11292**	**11250**
42	**Total Surplus/Deficit**	**414**	**199**	**467**	**69**	**98**	**53**	**66**	**10**	**15**	**-123**

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Exhibit 4-4: Monthly 120-Hour Capacity

Federal System Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Federal System
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**
S241-WB-20230315-141333

120Hr-MW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Obligations	2016	2008	2016	2006	2014	2009	2002	2004	1992	1994	2008	2005	1994	1994
1 **Load Following**	4505	4197	3789	3960	4348	5177	5151	4786	4441	4239	4274	4058	4507	4731
2 Preference Customers	4965	4965	4408	4733	5271	6087	6182	5882	5385	5106	5106	4652	4963	5101
3 Federal Agencies	160	160	148	179	204	225	224	242	209	184	184	163	163	185
4 USBR	620	620	577	407	104	144	201	177	343	425	425	520	600	619
5 Federal Diversity	-1240	-1548	-1344	-1359	-1231	-1280	-1456	-1514	-1497	-1476	-1441	-1276	-1219	-1174
6 **Tier 1 Block**	353	353	606	522	870	897	952	843	847	401	401	149	23.0	339
7 Tier 1 Block	353	353	606	522	870	897	952	843	847	401	401	149	23.0	339
8 **Slice**	2634	2748	2632	2591	3264	3759	3606	3571	3456	2790	2494	3160	3080	2811
9 Slice Block	1131	1131	1114	1136	1322	1510	1494	1331	1276	1178	1178	1133	1084	1120
10 Slice Output from T1 System	1503	1617	1518	1455	1942	2249	2112	2240	2180	1612	1316	2026	1997	1691
11 **Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12 Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13 **Contract Deliveries**	1536	1617	1476	1451	1458	1458	1458	1458	1451	1451	1451	1451	1451	1480
14 Exports	1201	1283	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1170
15 Intra-Regional Transfers (Out)	334	334	334	309	316	316	316	316	309	309	309	309	309	309
16 **Total Firm Obligations**	**9039**	**8926**	**8514**	**8535**	**9951**	**11301**	**11178**	**10670**	**10205**	**8891**	**8631**	**8829**	**9072**	**9371**
Net Resources														
17 **Hydro**	9116	9280	8977	8604	10790	11790	11828	11257	11244	8901	7975	11677	10864	10014
18 Regulated Hydro - Net	8658	8675	8591	8095	10341	11443	11287	10893	10924	8418	7343	11137	10320	9422
19 Independent Hydro - Net	455	601	383	505	445	343	536	359	316	479	627	535	540	589
20 Small Hydro - Net	3.49	3.49	3.00	4.11	4.49	4.60	4.59	4.62	4.58	4.58	4.58	4.58	4.09	3.19
21 **Non-Hydro Renewable**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22 Wind - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 **Thermal**	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
26 Nuclear - Net	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
27 Coal - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Natural Gas - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Biofuel - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Cogeneration - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 **Contract Purchases**	271	273	315	414	474	580	627	529	478	417	412	275	282	275
33 Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
34 Intra-Regional Transfers (In)	0	0	50.0	150	200	300	350	250	200	150	150	0	0	0
35 Non-Federal CER	235	235	235	235	235	235	235	235	235	235	235	235	235	235
36 Slice Transmission Loss Return	34.5	37.2	29.5	28.2	37.7	43.7	41.0	43.5	42.3	31.3	25.6	39.3	45.9	38.9
37 **Reserves & Losses**	-1844	-1851	-1864	-1776	-1944	-2039	-2042	-1989	-1967	-1814	-1758	-1942	-1913	-1873
38 Operating Reserves	-660	-662	-619	-626	-725	-789	-790	-756	-734	-654	-625	-697	-687	-676
39 Balancing Reserves	-894	-894	-964	-877	-878	-878	-878	-878	-878	-878	-878	-878	-878	-878
40 Transmission Losses	-290	-296	-281	-274	-341	-372	-374	-355	-355	-282	-255	-367	-348	-319
41 **Total Net Resources**	**8706**	**8864**	**8607**	**8422**	**10499**	**11510**	**11592**	**10972**	**10932**	**8671**	**7795**	**11161**	**10387**	**9584**
42 **Total Surplus/Deficit**	**-333**	**-62**	**93**	**-113**	**548**	**209**	**414**	**302**	**727**	**-221**	**-836**	**2,332**	**1,315**	**213**

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Federal System Analysis Surplus Deficit
Operating Year 2024

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Federal Report Surplus Deficit By Water Year
Operating Year 2024
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230315-141333

Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1 1989 Federal Report Surplus Deficit	214	991	-258	-603	215	-106	-60.4	-1090	932	1803	2926	2754	1969	285	588
2 1990 Federal Report Surplus Deficit	258	143	-18.0	-230	920	768	1688	3631	1085	1613	2472	2424	4361	2263	1581
3 1991 Federal Report Surplus Deficit	2206	2211	127	-387	2374	1418	3021	3945	2571	2004	1452	2829	3954	3733	2287
4 1992 Federal Report Surplus Deficit	2628	1996	-32.6	-280	383	-1035	-24.2	771	-468	-95.6	-214	2342	1146	-272	388
5 1993 Federal Report Surplus Deficit	115	-32.8	60.5	-623	208	-652	-953	-1595	264	287	-1013	3459	2788	1067	315
6 1994 Federal Report Surplus Deficit	665	516	470	-229	294	-610	-732	-192	-112	-443	783	1761	1239	158	233
7 1995 Federal Report Surplus Deficit	70.9	-240	60.1	-439	116	-329	119	1238	2643	550	155	2274	3978	2143	1003
8 1996 Federal Report Surplus Deficit	717	765	553	761	2871	5040	5419	5794	5744	2630	4122	3617	4732	4688	3607
9 1997 Federal Report Surplus Deficit	2362	2614	351	15.8	796	1561	5600	5496	4913	3189	5466	5756	6411	4996	3555
10 1998 Federal Report Surplus Deficit	2751	3082	1423	2265	1803	451	1412	2787	1376	490	555	5044	4360	2561	2243
11 1999 Federal Report Surplus Deficit	2475	1325	387	-214	-76.9	812	4220	3896	5348	2213	3102	3164	4802	4645	2627
12 2000 Federal Report Surplus Deficit	2972	3361	129	-155	1980	1976	2557	2585	2546	2515	3137	2966	2164	1232	1997
13 2001 Federal Report Surplus Deficit	1450	-29.9	-46.0	-224	46.8	-886	-702	3.36	-373	-939	-1562	619	558	-23.7	-133
14 2002 Federal Report Surplus Deficit	372	-158	-224	-687	-271	-274	-427	-211	409	1166	2787	2553	4514	3287	895
15 2003 Federal Report Surplus Deficit	1332	1164	26.1	-280	394	-767	-555	324	1714	1091	1194	1877	3767	108	745
16 2004 Federal Report Surplus Deficit	-250	-145	-120	-444	912	340	-231	-831	318	587	553	1972	2744	704	479
17 2005 Federal Report Surplus Deficit	-366	413	220	403	832	1174	1063	2526	584	-498	-432	1566	2237	1405	959
18 2006 Federal Report Surplus Deficit	415	53.9	57.4	-634	832	359	2827	4275	1837	3181	2547	4639	3469	2144	1896
19 2007 Federal Report Surplus Deficit	289	-75.8	-85.0	-443	531	467	2408	1206	3971	2162	1527	2568	2590	1325	1376
20 2008 Federal Report Surplus Deficit	16.3	-284	-333	-462	608	-583	665	725	911	230	-522	3400	5463	2893	1082
21 2009 Federal Report Surplus Deficit	1169	1462	271	-274	491	-741	1913	658	-301	2625	2135	2752	2655	686	981
22 2010 Federal Report Surplus Deficit	-109	-626	-60.5	-357	231	-160	-875	-567	-589	21.3	-656	693	4264	2032	324
23 2011 Federal Report Surplus Deficit	329	-83.8	269	-406	-34.9	938	3067	4229	2993	4829	2015	4077	6699	6345	2634
24 2012 Federal Report Surplus Deficit	3565	2328	437	145	646	197	1578	2463	3390	4679	5187	4159	5410	5041	2608
25 2013 Federal Report Surplus Deficit	2822	2643	85.0	-178	1560	2101	1097	996	323	3751	2009	3466	3518	2328	1743
26 2014 Federal Report Surplus Deficit	988	327	353	-101	271	-615	1936	-227	3547	3522	2550	3610	3648	2570	1563
27 2015 Federal Report Surplus Deficit	1888	1303	239	-364	1495	1939	2729	3796	4259	1814	87.1	890	890	-407	1494
28 2016 Federal Report Surplus Deficit	-49.4	-308	-296	-405	53.9	-13.2	502	-163	3754	3062	3423	2933	1892	493	987
29 2017 Federal Report Surplus Deficit	72.4	-127	141	-428	2018	554	2544	2692	6325	5162	4785	5860	5350	1739	2639
30 2018 Federal Report Surplus Deficit	1900	1138	-32.9	-329	-334	565	3286	4230	3423	2966	2307	5347	3770	1170	2098

Ranked Averages

31 **Bottom 10 pct**	**-4217**	**-4449**	**-4052**	**-3991**	**-4651**	**-5562**	**-5591**	**-5000**	**-4695**	**-4226**	**-4302**	**-3853**	**-3963**	**-4579**	**-133**
32 **Middle 80 pct**	**-3343**	**-3438**	**-3281**	**-3317**	**-3616**	**-4394**	**-4262**	**-3815**	**-3398**	**-2947**	**-3001**	**-2479**	**-2447**	**-3351**	**1032**

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Water-Year Percentile by Month
Operating Year 2024 - 2033

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	Water Year	Hydro Modeling 14 - Period													
		Aug - I	Aug - II	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr - I	Apr - II	May	Jun	Jul
Firm Water Condition - P10	Energy aMW														
	OY2024	2016	2008	2002	1989	2011	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2025	2016	2008	2002	1989	1989	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2026	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2027	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2028	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2029	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2030	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2031	2016	2008	2002	1989	2011	1993	2010	1994	1994	1992	2008	1994	2005	2001
	OY2032	2016	2008	2002	1989	1989	1993	2010	1994	1994	2010	2008	2005	1994	2003
	OY2033	2016	1995	2002	1989	1989	1993	2001	1994	1994	1992	2008	1994	2005	2001
	120HR-MW														
	OY2024	2016	2008	2016	2006	2014	2009	2002	2004	1992	1994	2008	2005	1994	1994
	OY2025	2016	2008	2016	2006	2010	2009	2002	2016	1992	1994	2008	1994	1992	2001
	OY2026	1993	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2027	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2028	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2029	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2030	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2031	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
	OY2032	2010	2017	2016	2006	1999	2003	2002	2016	1992	1994	2010	2005	1994	1994
	OY2033	1993	2008	2016	2006	1999	2003	2001	2016	1992	1994	2010	1994	2005	2001
Median Water Condition - P50	Energy aMW														
	OY2024	1994	2005	2006	2018	2007	2004	1998	1995	2003	1991	2011	1991	2013	2017
	OY2025	2003	2005	2006	2018	2007	2004	1998	2007	2003	1990	2011	1999	2003	2006
	OY2026	1994	2005	2006	2018	2009	2004	2012	1995	2006	2015	2011	2000	2003	2017
	OY2027	1996	1999	2006	2018	2007	2004	1998	1995	2003	2015	2011	2009	2013	2006
	OY2028	1994	2005	2006	2018	2007	2004	1998	1995	2006	2015	2011	1991	2003	2010
	OY2029	2003	1999	2006	2018	2009	2004	1998	1995	2003	2015	2011	2016	2006	1993
	OY2030	1994	2005	2006	2018	2009	2006	1998	1995	2006	1991	2011	1991	2006	2017
	OY2031	2003	2005	2006	2018	2009	2004	1998	2007	2006	2015	2011	2016	2006	1993
	OY2032	1994	2005	2006	2018	2009	2004	2012	2007	2006	1991	2011	2000	2006	2017
	OY2033	2003	2005	1995	2003	2009	2004	1998	1995	2003	2015	2013	2009	2006	2006
	120HR-MW														
	OY2024	2014	2005	1990	1992	2012	2017	2005	2007	2006	2015	2013	2016	2018	2017
	OY2025	2017	1999	1990	2009	2009	2004	2009	1995	2006	1991	2013	1989	1998	1993
	OY2026	1994	2005	2018	2009	2003	2004	2009	1995	2006	1989	2013	2016	2018	2017
	OY2027	2003	1999	1990	2017	2012	2017	2009	1995	2006	1991	2013	1989	2018	2006
	OY2028	1994	2005	2018	2009	2009	2004	2009	1995	2006	1989	2013	2016	2018	2017
	OY2029	2014	1999	1990	2017	2012	2004	2012	1995	2006	1990	2011	1995	2018	2006
	OY2030	1994	2005	2018	2009	2003	2004	2009	1995	2006	1990	2013	2000	2018	2017
	OY2031	2003	1999	1990	2017	2009	2004	2012	1995	2006	1991	2013	1995	2014	2006
	OY2032	1994	2005	2018	2009	2009	2017	2009	1995	2003	1989	2013	2000	2018	2017
	OY2033	2014	1999	2015	2017	2009	2017	2012	1995	2006	1990	2011	1989	2018	2006
High Water Condition - P90	Energy aMW														
	OY2024	1998	1997	2012	2012	2017	2015	2018	2011	1997	2013	1996	1998	2012	1999
	OY2025	1998	1997	2012	2012	2017	2015	2018	2018	1997	1997	2016	1998	2017	1996
	OY2026	1998	2012	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2027	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2028	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2029	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2030	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2031	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	OY2032	2013	1997	2012	2012	2000	2015	2018	2011	1997	2014	1996	1998	2012	1999
	OY2033	1998	1997	2012	2012	2017	2015	2018	2018	1997	2016	1996	2018	2008	1997
	120HR-MW														
	OY2024	1997	1997	1999	2012	1998	2015	1991	2011	2015	2013	2016	1998	2010	1996
	OY2025	2013	1997	1999	2012	1998	2015	1991	2011	2015	2011	1996	1998	2017	2012
	OY2026	2013	2012	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2027	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2028	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2029	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2030	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2031	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	2017	1996
	OY2032	1999	1997	1999	2012	2017	2015	1991	2011	2015	2013	2016	1998	2017	1996
	OY2033	1997	2013	1999	2012	1998	2015	1991	2011	2015	2016	1996	2006	1997	1996

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Section 5: Pacific Northwest Regional Analysis Exhibits

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Regional Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Pacific Northwest Region
Operating Year: 2024 Water Year: P10
2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**
S241-WB-20230201-101234

	Energy-aMW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Regional Loads										
1	**Retail Loads**	24164	24439	24600	24808	25001	25170	25266	25339	25378	25470
2	Federal Agency	148	157	163	166	168	169	170	170	170	170
3	USBR	188	188	188	188	188	188	188	188	188	188
4	Cooperative	2854	2995	3078	3200	3322	3380	3419	3440	3453	3474
5	Municipality	2562	2566	2568	2570	2570	2575	2578	2584	2580	2591
6	Public Utility District	4901	4966	5011	5071	5129	5204	5256	5294	5321	5350
7	Investor-Owned Utility	13455	13510	13535	13557	13569	13598	13599	13608	13611	13641
8	Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9	Direct-Service Industry	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
10	Federal Diversity	0	0	0	0	0	0	0	0	0	0
11	**Exports**	1019	1021	1024	1021	1022	1020	1018	770	675	675
12	Canada	465	468	471	468	469	469	469	469	469	469
13	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	Inland Southwest	0	0	0	0	0	0	0	0	0	0
15	Pacific Southwest	553	552	552	552	552	550	548	300	205	205
16	Other	0	0	0	0	0	0	0	0	0	0
17	**Total Regional Loads**	**25183**	**25461**	**25624**	**25829**	**26023**	**26190**	**26284**	**26110**	**26053**	**26146**
	Regional Resources										
18	**Hydro**	12081	12110	12061	12099	12062	12099	12062	12099	12061	11981
19	Regulated Hydro - Net	10868	10868	10834	10872	10836	10872	10835	10872	10836	10764
20	Independent Hydro - Net	969	998	984	983	983	983	984	983	983	974
21	Small Hydro - Net	243	244	244	244	243	244	244	244	243	244
22	**Non-Hydro Renewable**	2711	2749	2748	2748	2748	2749	2748	2733	2744	2748
23	Wind - Net	2200	2238	2238	2238	2236	2238	2238	2222	2233	2238
24	Solar - Net	352	353	353	353	353	353	353	353	353	353
25	Other - Net	159	159	158	158	159	159	158	158	158	158
26	**Thermal**	13002	12795	12443	12175	12197	12102	12279	12028	12197	12157
27	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
28	Coal - Net	3751	3676	3201	3049	2955	2981	3034	2948	2962	3034
29	Natural Gas - Net	5373	5372	5371	5371	5373	5372	5368	5371	5372	5371
30	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
31	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
32	Cogeneration - Net	2737	2727	2729	2736	2728	2730	2736	2690	2721	2733
33	**Imports**	588	591	595	599	603	607	610	130	36	36
34	Canada	38.8	38.8	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4
35	East of Continental Divide	0	0	0	0	0	0	0	0	0	0
36	Inland Southwest	502	506	509	513	517	521	525	94		
37	Pacific Southwest	47.1	47.1	47.1	47.1	47.1	47.1	47.1	0.0	0.0	0.0
38	Other	0	0	0	0	0	0	0	0	0	0
39	**Reserves & Losses**	-883	-880	-867	-860	-860	-858	-862	-841	-842	-838
40	Operating Reserves	0	0	0	0	0	0	0	0	0	0
41	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
42	Transmission Losses	-883	-880	-867	-860	-860	-858	-862	-841	-842	-838
43	**Total Regional Resources**	**27499**	**27366**	**26980**	**26761**	**26751**	**26699**	**26837**	**26150**	**26197**	**26085**
44	**Total Surplus/Deficit**	**2316**	**1905**	**1357**	**932**	**728**	**509**	**553**	**40**	**144**	**-61**

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Regional Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Pacific Northwest Region

Operating Year: 2024 Water Year: P10

2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Regional Loads															
1 **Retail Loads**	24532	24549	22061	21872	23791	27239	27403	25401	23803	22650	22650	22270	23640	25230	24164
2 Federal Agency	124	124	115	140	154	185	187	169	157	145	145	131	131	140	148
3 USBR	330	329	286	123	9.67	10.8	8.39	18.0	61.0	234	234	345	395	427	188
4 Cooperative	2956	2958	2682	2408	2633	3030	3109	2924	2778	2706	2706	2802	3007	3209	2854
5 Municipality	2301	2303	2219	2402	2715	3098	3123	2943	2721	2468	2468	2235	2215	2303	2562
6 Public Utility District	4652	4656	4330	4464	5015	5743	5841	5390	4987	4667	4667	4397	4556	4770	4901
7 Investor-Owned Utility	14113	14123	12374	12278	13209	15116	15078	13901	13044	12374	12374	12305	13281	14326	13455
8 Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9 Direct-Service Industry	52.2	52.2	52.9	53.8	54.2	53.9	54.3	54.0	53.5	53.9	53.9	52.4	52.1	52.1	53.3
10 Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 **Exports**	1065	1328	1114	846	1003	873	679	825	880	1215	1102	1147	1192	1313	1019
12 Canada	512	598	454	454	454	454	454	454	454	454	454	454	454	483	465
13 East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14 Inland Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Pacific Southwest	552	729	659	390	548	417	223	369	425	760	647	692	737	829	553
16 Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 **Total Regional Loads**	**25597**	**25876**	**23175**	**22717**	**24794**	**28112**	**28082**	**26225**	**24683**	**23865**	**23753**	**23417**	**24832**	**26543**	**25183**
Regional Resources															
18 **Hydro**	10268	10424	9680	9468	12772	12264	13459	12220	12157	12010	10436	14953	14121	12294	12081
19 Regulated Hydro - Net	9116	9103	8687	8438	11669	11209	12324	11211	11018	10883	9046	13383	12510	10901	10868
20 Independent Hydro - Net	827	998	749	867	975	929	1012	877	978	846	1108	1167	1189	988	969
21 Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	243
22 **Non-Hydro Renewable**	2163	2869	2597	2127	2668	2173	1376	2057	2382	3875	3364	3656	3721	3646	2711
23 Wind - Net	1511	2216	2046	1651	2298	1869	1046	1661	1895	3311	2799	3023	3046	2951	2200
24 Solar - Net	492	492	392	315	211	144	181	236	327	406	406	471	535	513	352
25 Other - Net	160	160	158	161	160	160	149	160	159	158	158	162	140	182	159
26 **Thermal**	13413	13420	13492	13528	13767	13867	13821	13751	12924	12911	11190	10154	11868	13413	13002
27 Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
28 Coal - Net	3821	3822	3825	3826	3824	3828	3828	3827	3799	3654	3457	3216	3842	3824	3751
29 Natural Gas - Net	5585	5592	5654	5719	5851	5921	5914	5853	5804	5484	4427	3403	4232	5587	5373
30 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	25.5
32 Cogeneration - Net	2867	2867	2871	2840	2949	2978	2939	2931	2177	2632	2165	2392	2653	2860	2737
33 **Imports**	580	580	510	482	669	770	605	605	508	455	455	503	656	708	588
34 Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	38.8
35 East of Continental Divide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Inland Southwest	560	559	494	460	449	485	456	471	445	425	425	474	617	681	502
37 Pacific Southwest	0	0	0	0	181	235	87.4	63.3	0	0	0	0	0	0	47.1
38 Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39 **Reserves & Losses**	-893	-923	-794	-773	-902	-878	-884	-865	-845	-883	-768	-884	-1026	-1016	-883
40 Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41 Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42 Transmission Losses	-893	-923	-794	-773	-902	-878	-884	-865	-845	-883	-768	-884	-1026	-1016	-883
43 **Total Regional Resources**	**25531**	**26370**	**25485**	**24831**	**28974**	**28195**	**28379**	**27768**	**27126**	**28368**	**24676**	**28382**	**29339**	**29045**	**27499**
44 **Total Surplus/Deficit**	**-65.7**	**494**	**2310**	**2113**	**4179**	**82.8**	**297**	**1543**	**2444**	**4503**	**924**	**4966**	**4507**	**2502**	**2316**

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Exhibit 5-3: Annual January 120-Hour Capacity

Regional Analysis Surplus Deficit
Operating Year 2024 to 2033
Firm Water Condition

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Loads and Resources - Pacific Northwest Region
Operating Year: 2024-2033 Water Year: P10 - January
2023 White Book - 30WY Report Date: **12/5/2022**

S241-WB-20230209-155822

	120Hr-MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Regional Loads										
1	**Retail Loads**	34526	34825	35084	35354	35632	35847	36020	36190	36331	36492
2	Federal Agency	232	240	246	248	252	254	255	255	256	256
3	USBR	201	201	201	201	201	201	201	201	201	201
4	Cooperative	4113	4267	4342	4461	4588	4633	4673	4700	4727	4752
5	Municipality	4226	4224	4248	4239	4215	4252	4259	4272	4269	4276
6	Public Utility District	7940	7992	8057	8133	8225	8328	8393	8456	8510	8548
7	Investor-Owned Utility	19202	19296	19386	19471	19552	19619	19676	19737	19805	19871
8	Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9	Direct-Service Industry	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4	65.4
10	Federal Diversity	-1456	-1462	-1465	-1467	-1468	-1509	-1504	-1498	-1505	-1482
11	**Exports**	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143
12	Canada	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142
13	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	Inland Southwest	0	0	0	0	0	0	0	0	0	0
15	Pacific Southwest	0	0	0	0	0	0	0	0	0	0
16	Other	0	0	0	0	0	0	0	0	0	0
17	**Total Regional Loads**	**35668**	**35968**	**36227**	**36496**	**36774**	**36989**	**37163**	**37333**	**37474**	**37634**
	Regional Resources										
18	**Hydro**	24046	24050	24120	23728	24120	23728	24120	23728	24120	23728
19	Regulated Hydro - Net	22255	22258	22329	22234	22329	22234	22329	22234	22329	22234
20	Independent Hydro - Net	1640	1640	1640	1342	1640	1342	1640	1342	1640	1342
21	Small Hydro - Net	151	151	151	151	151	151	151	151	151	151
22	**Non-Hydro Renewable**	182	182	182	182	182	182	182	182	182	182
23	Wind - Net	0	0	0	0	0	0	0	0	0	0
24	Solar - Net	0	0	0	0	0	0	0	0	0	0
25	Other - Net	182	182	182	182	182	182	182	182	182	182
26	**Thermal**	14910	14910	14106	14106	14106	14106	14106	14046	14106	14106
27	Nuclear - Net	1178	1178	1178	1178	1178	1178	1178	1178	1178	1178
28	Coal - Net	4195	4195	3392	3392	3392	3392	3392	3392	3392	3392
29	Natural Gas - Net	6288	6288	6288	6288	6288	6288	6288	6288	6288	6288
30	Petroleum - Net	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
31	Biofuel - Net	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
32	Cogeneration - Net	3179	3179	3179	3179	3179	3179	3179	3119	3179	3179
33	**Imports**	1065	1068	1071	1075	1078	1081	1085	150	150	150
34	Canada	155	155	155	155	155	155	155	150	150	150
35	East of Continental Divide	0	0	0	0	0	0	0	0	0	0
36	Inland Southwest	610	613	616	620	623	626	630	0	0	0
37	Pacific Southwest	300	300	300	300	300	300	300	0	0	0
38	Other	0	0	0	0	0	0	0	0	0	0
39	**Reserves & Losses**	-4085	-4086	-4046	-4032	-4062	-4047	-4075	-4027	-4055	-4037
40	Operating Reserves	-2063	-2056	-2038	-2035	-2054	-2051	-2067	-2061	-2076	-2070
41	Balancing Reserves	-878	-886	-886	-886	-886	-886	-886	-886	-886	-886
42	Transmission Losses	-1144	-1144	-1122	-1110	-1122	-1110	-1122	-1079	-1093	-1081
43	**Total Regional Resources**	**36118**	**36123**	**35433**	**35059**	**35423**	**35049**	**35418**	**34079**	**34503**	**34129**
44	**Total Surplus/Deficit**	**449**	**155**	**-794**	**-1438**	**-1351**	**-1940**	**-1745**	**-3254**	**-2971**	**-3506**

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Exhibit 5-4: Monthly 120-Hour Capacity

Regional Analysis Surplus Deficit
Operating Year 2024
Firm Water Condition

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Loads and Resources - Pacific Northwest Region

Operating Year: 2024 Water Year: P10

2023 White Book - 30WY (2001/P10) Report Date: **12/5/2022**

S241-WB-20230315-141333

120Hr-MW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Regional Loads														
1 **Retail Loads**	31680	31372	27945	27569	30346	34101	34526	31858	30408	28528	28563	27489	30490	32359
2 Federal Agency	172	172	159	195	207	238	232	235	216	200	200	177	179	193
3 USBR	620	620	577	407	104	144	201	177	343	425	425	520	600	619
4 Cooperative	3670	3670	3309	3290	3559	4002	4113	3897	3698	3601	3601	3529	3715	3895
5 Municipality	3189	3189	2922	3220	3700	4219	4226	4032	3727	3415	3415	3006	3045	3210
6 Public Utility District	6408	6408	5795	6127	6899	7780	7940	7485	6981	6515	6515	5961	6149	6365
7 Investor-Owned Utility	18795	18795	16461	15623	17042	18929	19202	17479	16872	15779	15779	15506	17953	19186
8 Marketer	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
9 Direct-Service Industry	62.8	62.8	63.4	64.6	65.0	65.0	65.4	64.7	65.0	65.4	65.4	64.2	64.3	63 0
10 Federal Diversity	-1240	-1548	-1344	-1359	-1231	-1280	-1456	-1514	-1497	-1476	-1441	-1276	-1219	-1174
11 **Exports**	1519	1601	1460	1151	1143	1143	1143	1143	1143	1143	1151	1151	1460	1488
12 Canada	1201	1283	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142	1170
13 East Continental Divide	1.00	1.00	1.00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1.00
14 Inland Southwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Pacific Sou hwest	317	317	317	8.04	0	0	0	0	0	0	8.04	8 04	317	317
16 O her	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 **Total Regional Loads**	**33199**	**32973**	**29405**	**28720**	**31489**	**35243**	**35668**	**33000**	**31550**	**29670**	**29714**	**28639**	**31949**	**33847**
Regional Resources														
18 **Hydro**	19826	21048	20711	20447	22370	23411	24046	23433	23158	20624	19793	23875	23091	22206
19 Regulated Hydro - Net	18066	19006	19162	18716	20983	22010	22255	21854	21561	18657	17693	21711	20918	20092
20 Independent Hydro - Net	1397	1682	1268	1534	1223	1245	1640	1415	1394	1648	1779	1723	1715	1675
21 Small Hydro - Net	363	361	280	197	164	156	151	164	203	319	320	441	459	439
22 **Non-Hydro Renewable**	193	193	193	194	193	193	182	194	193	193	193	194	192	192
23 Wind - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24 Solar - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 O her - Net	193	193	193	194	193	193	182	194	193	193	193	194	192	192
26 **Thermal**	14433	14434	14526	14668	14818	14904	14910	14836	14149	14032	12498	13271	13995	14437
27 Nuclear - Net	1163	1163	1179	1181	1179	1180	1178	1175	1177	1166	1166	1151	1154	1168
28 Coal - Net	4194	4194	4193	4194	4194	4195	4195	4195	4194	4194	4194	3861	4193	4193
29 Natural Gas - Net	5929	5929	5989	6084	6213	6282	6288	6224	6176	5772	4717	5615	5496	5932
30 Petroleum - Net	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
31 Biofuel - Net	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
32 Cogeneration - Net	3078	3078	3096	3141	3163	3177	3179	3173	2533	2832	2352	2576	3082	3075
33 **Imports**	942	942	799	739	986	1093	1065	1098	800	705	705	748	1016	1097
34 Canada	146	146	146	147	102	124	155	188	213	147	147	147	146	146
35 East of Continental Divide	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Inland Southwest	796	796	653	592	584	669	610	610	587	558	558	601	870	951
37 Pacific Sou hwest	0	0	0	0	300	300	300	300	0	0	0	0	0	0
38 O her	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39 **Reserves & Losses**	-3878	-3945	-3771	-3662	-3884	-4054	-4085	-3973	-3863	-3679	-3541	-3776	-3999	-4015
40 Operating Reserves	-1865	-1890	-1779	-1759	-1914	-2050	-2063	-1968	-1895	-1791	-1724	-1811	-1903	-1933
41 Balancing Reserves	-894	-894	-964	-877	-878	-878	-878	-878	-878	-878	-878	-878	-878	-878
42 Transmission Losses	-1119	-1160	-1028	-1026	-1092	-1126	-1144	-1127	-1091	-1010	-939	-1087	-1218	-1205
43 **Total Regional Resources**	**31516**	**32672**	**32458**	**32386**	**34484**	**35547**	**36118**	**35587**	**34436**	**31875**	**29647**	**34311**	**34296**	**33917**
44 **Total Surplus/Deficit**	**-1683**	**-300**	**3053**	**3666**	**2995**	**304**	**449**	**2587**	**2886**	**2205**	**-66.5**	**5672**	**2346**	**69.7**

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Regional Analysis Surplus Deficit
Operating Year 2024

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Regional Report Surplus Deficit By Water Year
Operating Year 2024
2023 White Book - 30WY Report Date: **12/5/2022**
S241-WB-20230209-155822

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1048	2663	2353	2113	4602	1628	906	281	4111	7914	9128	7491	6530	3491	3657
2	1990 Regional Report Surplus Deficit	1187	1259	2912	2784	6174	4224	5277	8719	5011	7696	7589	6827	10534	7174	5680
3	1991 Regional Report Surplus Deficit	4750	5077	3120	2844	9486	4794	6602	10030	7224	8498	5480	7434	9834	10009	6919
4	1992 Regional Report Surplus Deficit	5705	4767	2996	2601	4565	156	1128	3777	1807	3609	1697	5930	3639	1363	2977
5	1993 Regional Report Surplus Deficit	543	541	2490	1840	4053	82.8	-1051	-360	2981	5165	842	8725	7559	4688	2882
6	1994 Regional Report Surplus Deficit	2446	1917	3716	2740	4087	599	-578	1543	2444	3454	4859	5895	4507	2519	2810
7	1995 Regional Report Surplus Deficit	387	299	2672	2294	3967	1606	1615	5162	7606	5269	2346	6985	10604	6568	4422
8	1996 Regional Report Surplus Deficit	2806	2233	3839	4933	10592	11542	11104	14021	13607	10002	11126	9386	11177	10990	9502
9	1997 Regional Report Surplus Deficit	5359	5572	3754	3570	5725	5230	11547	13276	12313	11313	12464	12666	14208	11924	9279
10	1998 Regional Report Surplus Deficit	6562	6973	6144	8501	7851	3326	4421	7735	5517	5734	3848	10768	11178	7579	7040
11	1999 Regional Report Surplus Deficit	5426	3565	3747	2905	4271	4131	9082	9840	12496	9176	8830	8535	12035	11934	7696
12	2000 Regional Report Surplus Deficit	7331	7646	3484	3336	8798	6268	5968	7343	6922	9707	9295	7909	7295	5151	6612
13	2001 Regional Report Surplus Deficit	3430	1493	2905	2860	3676	-241	-923	1970	1274	3124	-653	2574	3115	1937	1892
14	2002 Regional Report Surplus Deficit	816	404	2310	1996	2857	1383	682	2095	3171	6653	7822	7129	10949	9013	4111
15	2003 Regional Report Surplus Deficit	2942	2864	3151	2481	4226	136	417	2998	5707	5970	4658	5779	9333	2502	3730
16	2004 Regional Report Surplus Deficit	-113	405	2467	2667	5338	2427	862	1285	2956	5113	3439	5868	7478	3597	3275
17	2005 Regional Report Surplus Deficit	-135	1621	3524	4027	5520	4291	3239	6364	3412	3115	1535	4966	6391	4607	4104
18	2006 Regional Report Surplus Deficit	1343	906	2851	2104	5263	2617	6995	9985	5934	10743	7990	10357	10448	6041	6059
19	2007 Regional Report Surplus Deficit	1346	743	3415	2172	5516	3038	5326	4942	10064	8792	5768	7116	7721	4914	5204
20	2008 Regional Report Surplus Deficit	1023	494	2872	2132	4204	909	1905	3383	3828	4292	924	8481	12441	8486	4325
21	2009 Regional Report Surplus Deficit	3407	3564	3306	2565	4967	501	4174	3143	1747	9118	6559	7503	8249	3629	4246
22	2010 Regional Report Surplus Deficit	674	-4.39	2990	2421	4192	1231	297	1538	1339	4503	629	3144	10860	6633	3115
23	2011 Regional Report Surplus Deficit	1953	1078	3236	2482	4179	3867	7423	10522	8708	13224	7355	9799	14280	14397	7536
24	2012 Regional Report Surplus Deficit	8140	5818	3933	3634	5154	2129	4420	6692	8631	12646	11996	9902	12091	12087	7320
25	2013 Regional Report Surplus Deficit	6043	5778	3320	2880	7163	5930	2909	4099	2894	11307	6046	8335	9581	6540	5679
26	2014 Regional Report Surplus Deficit	2345	1566	3658	3263	4336	459	4401	1801	9357	10528	7553	8550	9600	7971	5370
27	2015 Regional Report Surplus Deficit	4230	3368	3206	2745	7043	5802	6382	10091	10039	7906	2578	3127	3639	1150	5165
28	2016 Regional Report Surplus Deficit	-65.7	-10.7	2790	1981	3588	2212	2444	2606	9359	10517	9398	7663	5928	2830	4271
29	2017 Regional Report Surplus Deficit	485	503	2827	3293	8452	3048	5434	7827	14454	14576	11750	11956	12517	5696	7408
30	2018 Regional Report Surplus Deficit	4428	2864	2875	2804	4026	3090	7205	10317	8687	10241	8275	11303	10132	4949	6500
	Ranked Averages															
31	**Bottom 10 pct**	**-9987**	**-9578**	**-7078**	**-7069**	**-8207**	**-11811**	**-12756**	**-10308**	**-9347**	**-7144**	**-9197**	**-9536**	**-9137**	**-9376**	
32	**Middle 80 pct**	**-6477**	**-6264**	**-4141**	**-4264**	**-4433**	**-7781**	**-8291**	**-6111**	**-5180**	**-3046**	**-5140**	**-4758**	**-4121**	**-5244**	**4261**

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Appendix A - Reports Available Upon Request OY2024 - 2033

1. Annual Energy

1.1. Federal Report Surplus/ Deficit – Annual
1.2. Regional Report Surplus/ Deficit – Annual
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1.4. Regional Exports – Annual
1.5. Regional Imports – Annual
1.6. Regional Intra-Regional Transfer – Annual
1.7. BPA Sales to Preference and Legacy Customers – Annual
1.8. Regional Regulated Hydro – Annual
1.9. Regional Independent Hydro – Annual
1.10. Regional Small Hydro – Annual
1.11. Regional Non-Hydro Renewable – Wind – Annual
1.12. Regional Non-Hydro Renewable – Solar – Annual
1.13. Regional Non-Hydro Renewable – Other – Annual
1.14. Regional Thermal – Nuclear – Annual
1.15. Regional Thermal – Coal – Annual
1.16. Regional Thermal – Natural Gas – Annual
1.17. Regional Thermal – Petroleum – Annual
1.18. Regional Thermal – Biofuel – Annual
1.19. Regional Thermal – Cogeneration – Annual
1.20. Non-Federal CER Deliveries to BPA – Annual
1.21. Federal Report Surplus/ Deficit by 80 Water Year – Annual
1.22. Regional Report Surplus/ Deficit by 80 Water Year – Annual

2. Monthly Energy

1.1. Federal Report Surplus/ Deficit – Monthly
1.2. Regional Report Surplus/ Deficit – Monthly
1.3. Regional Total Retail Load – Monthly
1.4. Regional Exports – Monthly
1.5. Regional Imports – Monthly
1.6. Regional Intra-Regional Transfer – Monthly
1.7. BPA Sales to Preference and Legacy Customers – Monthly
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1.9. Regional Independent Hydro – Monthly
1.10. Regional Small Hydro – Monthly
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1.17. Regional Thermal – Petroleum – Monthly
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1.19. Regional Thermal – Cogeneration – Monthly
1.20. Non-Federal CER Deliveries to BPA – Monthly
1.21. Federal Report Surplus/ Deficit by 80 Water Year – Monthly
1.22. Regional Report Surplus/ Deficit by 80 Water Year – Monthly

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5226 ▪ April 2023

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-141a:
2024 Bonneville White Book

2024 Pacific Northwest Loads and Resources Study

August 2024

2024 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
August 2024

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

The John Day Dam is one of the four Federal projects located on the Lower Columbia River in the Pacific Northwest; it is part of the Columbia River Basin hydro projects. It is located to the east of The Dalles and right near the mouth of the John Day River. The John Day Dam was constructed between 1958 and 1971, it was built and operated by the U.S. Army Corps of Engineers.

The John Day Dam is a run-of-river type of Dam, and it has a navigation lock, as well as fish ladders on both sides of the project.

For more information on The John Day Dam, please visit John Day Lock & Dam at https://www.nwp.usace.army.mil/John-Day/

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

August 15, 2024

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten-year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS) or to determine BPA revenues or rates.

In recent news, the U.S. and Canada have reached a historic milestone in the years-long effort to modernize the Columbia River Treaty. The two countries reached an agreement in principle outlining a framework for managing our shared resource, the Columbia River, in a way that will deliver tremendous value on both sides of the border. However, since this news is so late breaking, the 2024 White Book does not reflect the agreement in principle. BPA plans to incorporate these changes in future studies including the next white book. For more information, see statement from the White House or fact sheet from the State Department.

The White Book has traditionally included different types of power planning forecasts showcasing BPA's and the region's ability to meet loads under different conditions and time periods. Some examples of the generation metrics include:

- Average energy per month,
- Average energy per year,
- 1 hour peak capacity per month,
- 50 hours per week sustained capacity, and
- 120 hours per month (January) sustained capacity

BPA's goal is to provide meaningful planning forecasts to the region by keeping up with emerging power markets, regional resource adequacy programs, FCRPS capabilities, climate change signals, and a host of other factors. To that end, BPA has decided not to include data related to its 120hr January sustained capacity metric in the 2024 White Book. BPA plans to review its capacity metrics and potentially make changes that would lead to more meaningful forecasts for regional stakeholders.

This 2024 White Book presents Federal system and the region's load obligations, contracts, and resources as of December 2023 for operating years (OY) 2025 through 2034. The 2024 White Book includes the following studies:

- **Federal System Analysis—**forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by different energy planning. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 79 aMW to 303 aMW. Overall, these annual energy deficit projections are less than those projected in the 2023 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses through the study period.
- **PNW Regional Analysis—**forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW region is projected to have an annual energy surplus as large as 1,426 aMW in OY 2025, rather sharply decreasing to a deficit of 2,738 aMW by OY 2034. This result was mainly driven by the increasing PNW Retail Loads. These annual energy projections are more deficit throughout the study period than was forecasted in the 2023 White Book. Under median water conditions, the PNW region would begin to see energy deficits in the out years.

BPA is currently working on its 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, carbon free resource requirements, and the most recent Climate Resiliency efforts. As with resources, there is also much uncertainty with loads including the potential for electrification. The 2024 White Book is available on BPA's website: *https://www.bpa.gov/energy-and-services/power/resource-planning* or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. The available report list can be found in the Appendix.

Please send questions and/or comments to whitebook@bpa.gov.

Sincerely,

MICHELLE CATHCART

Digitally signed by MICHELLE CATHCART
Date: 2024.08.26 19:13:13 -07'00'

Michelle Cathcart
Vice President| General Asset Management
Bonneville Power Administration
Enclosure

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SECTION 1: SUMMARY

Planning Context

The Pacific Northwest Loads and Resources Study, commonly referred to as the White Book, is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period. The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest[1] (PNW) region. Information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. The load and resource balance is calculated by comparing expected loads and contract obligations to forecast resource generation and contract purchases under the Federal system. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW regional include variability by incorporating a variety of generation forecasts, associated with streamflow from the most recent 30-historical water conditions[2] of the 2020 Modified Flows. These deterministic analyses are modeled by operating year (OY[3]), defined as August to July, to be consistent with regional coordination of the Treaty and Pacific Northwest Coordination Association (PNCA). Analytical results are presented in annual and monthly energy, expressed in average megawatts (aMW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to comprehensively assess the ability of the power system to meet long-term load obligations. Periodically, Bonneville incorporates additional studies and data into its planning that look at different analytical methods and evaluate different scenarios. This year's White Book does not incorporate any other special studies.

The total retail load, contracts, and generation forecasts used in this study were updated as of December 31, 2023. The 2024 White Book supersedes the 2023 White Book and is published as a single summary document.

[1] As defined in the Northwest Power Act

[2] Bonneville Power Administration Climate Change & FCRPS

[3] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2024 is August 1, 2023 through July 31, 2024.

A list of technical reports can be located at the end of this summary document in the Appendix, individual reports are available upon request only. Request for these reports can be made by emailing WhiteBook@bpa.gov.

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, forecasts are categorized as: 1) Total Retail Loads (TRL), defined as each individual utility's total retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region as Intra-Regional Transfers (Out) and outside the PNW region as Exports. Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperatives, and tribal utility as preference customers, as described under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches, the largest share of load forecasts is now based on statistically adjusted end-use models while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions and do not include any explicit adjustments for the impacts of climate change or the Inflation Reduction Act[4] (IRA); however, the forecasts do use normalized temperatures based on recent history in order to incorporate recent climate trends. Contract obligations not associated with Bonneville's Preference Power Sales Contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of physical generating facilities (currently on-line and under construction) and contract purchases that are used to serve retail loads. PNW resources, with Federal systems included, are predominantly hydro based; therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other renewable projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW regional as Intra-Regional Transfer (In) and from outside the PNW regional as Imports. Generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described in detail in the following sections.

[4] Inflation Reduction Act | U.S. Department of the Treasury

Hydro Resources

- Regulated Hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydro-system Simulator (HYDSIM) model. The HYDSIM model considers individual project operating characteristics and conditions to determine energy production expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.
- Independent Hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/ operators for the same 30-historical water conditions as the Regulated Hydro projects (1989 through 2018).
- Small Hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month, however they are not assumed to vary by water conditions.

Non-Hydro Resources

- Wind – Firm wind generation incorporates the statistical modeling of wind generation based on historical weather data and actual generation from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as firm wind year. The firm wind year generation performance determines each project's energy forecast. The Federal system and PNW regional capacity analysis assume zero capacity contribution from wind resources.
- Solar – Solar projects are utility scale solar facilities that are metered, and the generation is being sent to the grid, and does not include any behind the meter resources, generation forecasts are either provided by individual project owners or are based on historical actual generation. The Federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other Renewable – Other renewable resources include all other projects identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal Resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel (not identified as renewable), and cogeneration projects. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced to account for scheduled maintenance.

Forecasts are adjusted to show actual operational capabilities and expectations, and not to reflect economic dispatch.

Contract Purchases/ Imports

- Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publicly and in data submittals. These purchases are treated as resources in both the Federal system and PNW regional analyses. Purchases between entities within the PNW are called Intra-regional Transfer (In) and purchases from entities outside the PNW are categorized as Imports. Except for contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms throughout the life of the contract and are not assumed to be renewed. Current Treaty power deliveries are assumed to be in place through the study period.

Adjustment to Resources

The White Book assumes that resource generation and contract purchases are reliably delivered to load centers. To take this assumption into account, this study adjusts generation forecasts for 1) Operating and Balancing Reserves, held to meet reliability standards; and 2) Transmission losses, associated with power deliveries. These adjustments are considered as reductions to both energy and capacity and are described below:

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing three percent of forecast load and three percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White book are modeled consistent with those used in Bonneville's BP-24 Rate Case process.
- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission Loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with Federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to Federal loads over non-Federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-24 Rate Case process:
    - Energy: 3.11 percent from September through May, and 3.16 percent from June through August.

- Capacity: 3.16 percent from September through May, and 3.21 percent from June through August.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month of the 30 year-historical streamflow record[5]: October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, first half -second half, due to natural streamflow and significant operational changes happening during these two months. Consequently, generations can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies encompass both power and non-power operating requirements. Each hydro study specifies particular non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The operations modeled include the following as outlined in the U.S. Army Corps of Engineers Pacific Northwest Coordination Agreement (PNCA) data submittals:

- National Marine Fisheries Services 2008 Willamette Biological Opinion (BiOp) (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 U.S. Fish and Wildlife Service Biological Opinion (November 12, 2019)

The PNCA coordinates the planning and operation of the members' hydroelectric power projects in the PNW. PNCA project owners provide physical plant data as well as power and non-power constraints in an annual data submittal to the Western Power Pool (WPP). Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. This coordination agreement expires on September 15, 2024. As with previous White Books, PNCA assumptions were included past the PNCA expiration date through the 10-year study horizon. The 2025 White Book will include studies that reflect the expiration of the PNCA.

The construction of the three storage projects in Canada - Mica, Arrow, and Duncan - under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and allows a Detailed Operating Plan (DOP) to be

[5] 2020 Modified Flows

completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2022 AOP studies, with additional modifications that reflect updates used in the official 2024 DOP studies.

Both the United States and Canada can terminate most of the provisions of the Treaty any time after September 16, 2014, with a minimum of 10 years advance notice. Neither Canada nor the United States have provided notice of termination; therefore, this study assumes the Treaty continues throughout the study period. Flood Risk Management (FRM) provisions in the Treaty are specified to change in OY25; as of the study vintage the way the FRM will change remained uncertain. This study extends FRM provisions in place for OY24 through the study period.

Bonneville has other operational agreements with Canada that are not part of the Treaty. One operational agreement is the Non-Treaty Storage Agreement (NTSA) that allows additional shaping of Columbia River flows for fish and power operations by utilizing storage not specified by the Treaty from Canadian reservoirs. The NTSA allows water to be released from Canadian project storage during the spring of dry years, it also allows water to be stored in the spring during years when flow targets from the 2008 NOAA BiOp would be met with a subsequent release of water in the summer. These operations are included in this study based on the NTSA signed with British Columbia Hydro in April 2012, which expires on September 15, 2024. This study assumes the NTSA continues through the study period.

Balancing reserves, both incremental and decremental, reduce the ability to shape the Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects. In this study, the impacts of incremental reserves are shown as a reduction in the capacity analyses and are categorized as operating and balancing reserves. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

Firm planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet obligation loads. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the Federal System this is established by considering the historical streamflow record, power and non-power operation constraints, the planned operation of non-hydro resources, combined with the system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program. For additional details, please refer to Bonneville's news release BPA adopts new streamflow forecast to reflect changing climate (Augus 1st, 2022) and Climate Change Resiliency Letter to the region (June 6, 2022).

Variability of Hydro Generation

The generating capacity of the Federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities, 2) the physical capacity of the facilities, 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or

applicable agreements, and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year to year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, Federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

- Firm water: tenth percentile (P10) of system generation by month, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month, it represents the exact middle value of generation distribution for energy and capacity of the hydro system.
- High water: 90th percentile (P90) of system generation by month, this represents the high generation scenario of the energy and capacity of the hydro system.

Hydro Capacity Modeling

Bonneville uses the RiverWare model to forecast usable hydro capacity for long-term planning purposes. RiverWare incorporates the monthly historical 30 water year reservoir storage and flows from HYDSIM to simulate the relationship of hydro energy to hydro peaking capability for Federal system regulated hydro resources. For each month, RiverWare forecasts hourly Federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts consider scheduled hydro maintenance and reserves.

For hydro resources, the 120-hour capacity forecasts are created by evaluating hourly generation from RiverWare over a specific period of time. This capacity metric is defined as the average generation forecasts from the six highest heavy load hours (HLH) per day, five days per week, and for four weeks per month (6x5x4 = 120 hours). While available, the White Book does not include 1-hour capacity forecasts because this metric does not represent a sustainable generation but rather a single hour peak, meaning it does not consider the ability of the hydro system to sustain generation level over a multiple hour period

The 120-hour capacity forecasts are not included in this (2024) White Book as Bonneville is currently working on improving its capacity metrics to better inform the region of the system's capacity while incorporating climate change, hydro modeling updates, and many ongoing improvements.

Notable Updates

The 2024 White Book includes updated forecasts of Federal system power sales contracts (PSC) obligations, PNW regional Total Retail Loads (TRL), contract purchases, and generation as of December 1, 2023, including:

- Hydro generation modeling excluded Lack-of-Market Spill study which puts upward pressure on generation values especially during runoff periods i.e. April through June.

- Updated RiverWare calibration on project behavior to correct 1) unrealistic results on peaking capacity and 2) violations to meeting Chum salmon requirements in the lower Columbia River and lower Snake River projects.
- Retirement dates associated with planned thermal generation projects.

Hydro capabilities in this study also reflect the updated Resilient Columbia Basin Agreement (RCBA, also known as the 12/14 agreement), published on 12/15/2023. Key items include:

- Spilling most projects in the spring to 125% Total Dissolved Gas (TDG) gas cap in the spring 24/7.
- John Day spills 40% of outflow for 16 hours during the day, and 125% TDG for 8 hours at night.
- Little Goose spill includes 8 hours of spill totaling 30% of outflow allowing for adult passage and 125% TDG for the remaining 16 hours, except 30% of outflow spill early in season does not begin until the sooner Apr 24th or adult criteria are met.
- Late summer spill transitions on August 1st instead of August 15th.
- Steelhead spill Sept-Nov 15th is everyday instead of every other day (4 hours per day via 1 Spillway Weir).
- Steelhead and early run juvenile spill is 24/7 beginning March 21st until the start of juvenile spill.

Sources of Uncertainty

Forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and a variety of other factors that could significantly affect the magnitude, duration, and timing of projected surpluses and/or deficits. Uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations,
- Changes to hydro system operations in response to court actions and/or operational agreements,
- Natural variations in weather affecting electrical power demand and streamflow runoff that result in hydroelectric power generation changes,
- Potential new large individual retail load and/or other changes to major industrial operations,
- Potential service to new load such as new customers or the Department of Energy's Richland vitrification plant operations,
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions,
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets,
- Changes to operating limits on existing and future thermal resources,
- Changes to retirement dates associated with resources,
- Failures of resources to operate at anticipated times and/or output levels,

- Changes to Treaty obligations and/or operations at the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future climate change impacts to retail loads, streamflow, and resources,

The potential impacts of these and other sources of uncertainty are not quantified in this study.

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SECTION 2: FEDERAL SYSTEM ANALYSIS

The Federal System Analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY2025 through 2034. This analysis incorporates forecasts of the Federal system's firm requirement PSC obligations, contract sales and purchases, and resource generations. This section presents firm Federal system load and resource forecasts for energy. Additional detailed components of the Federal system study are available only upon request, a list of available reports can be found in the Appendix.

Load Obligations

Bonneville's ALF system is used to forecast Federal system load obligations, as described previously in Section 1: Summary – Load Obligations. Types of Federal system load obligations include: 1) Federal reserve power obligations to the U.S. Bureau of Reclamation (USBR), 2) Bonneville's Regional Dialogue PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers, 3) contract obligations to investor-owned utilities (IOUs), 4) contract obligations to Direct Service Industry (DSI) customers, and finally 5) other Bonneville contract obligations including contract sales to entities within the PNW region (Intra-Regional Transfers (OUT)) and to those outside the PNW region (Exports). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather conditions, water supply, or economic environments. Bonneville's forecasts are these obligations are categorized in the following sections.

USBR obligations

USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. The remaining power from USBR projects are marketed by Bonneville in the PNW.

Regional Dialogue (RD) Contract High Water Mark (CHWM) PSC obligations to Public & Federal agency customers

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 121 are Load Following customers, 10 are Slice/Block, and three are Block.

Under the RD PSCs, customers must make periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[6] load by 1) adding new non-Federal resources; 2) acquiring power from

[6] "Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either non-Federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-Federal resources. (P.4 Regional Dialogue July 2007)

non-Federal resources; and/or 3) requesting Bonneville to supply additional power. The current customer elections have been set through fiscal year (FY) 2025, and this study assumes that current elections for FY2025, continue throughout the study period. Based on this assumption, Federal system RD PSC obligation forecasts include elected and forecasted A-RHWM load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY, which are consistent with the BP-24 Final Rate Proposal following the Rate Settlement for BP24 Rate Case.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP24 Rate Case)

FY	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy aMW	382.1	407.6	433.9	460.3	495.4	515.7	536.2	548.6	575.4	602.9

IOU Load Service under Regional Dialogue (RD) PSCs

There are six IOUs in the PNW region, and they are: Avista Corporation, Idaho Power Company, Northwestern Energy Division of Northwestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Although these IOUs all signed Bonneville RD PSCs for FY 2011 through FY 2028, no IOUs have elected to take power service under these contracts thus no net requirement power sales are assumed for the IOUs through this study period.

Direct Service Industrial (DSI) Contracts

Bonneville currently has one DSI customer, Port Townsend Paper Corporation. DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations

Bonneville provides federal power under a variety of additional contract arrangements. These contracts obligations are categorized as: 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payment for services; and 5) power commitments under the Treaty. These arrangements, collectively referred to as "Other Contract Obligations", are determined by individual contract provisions and have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region as Intra-Regional Transfers (Out), and to those outside of the PNW region as Exports.

Treaty, RD PSCs, and DSI power deliveries are assumed to remain in place throughout the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after the expiration date.

Conservation

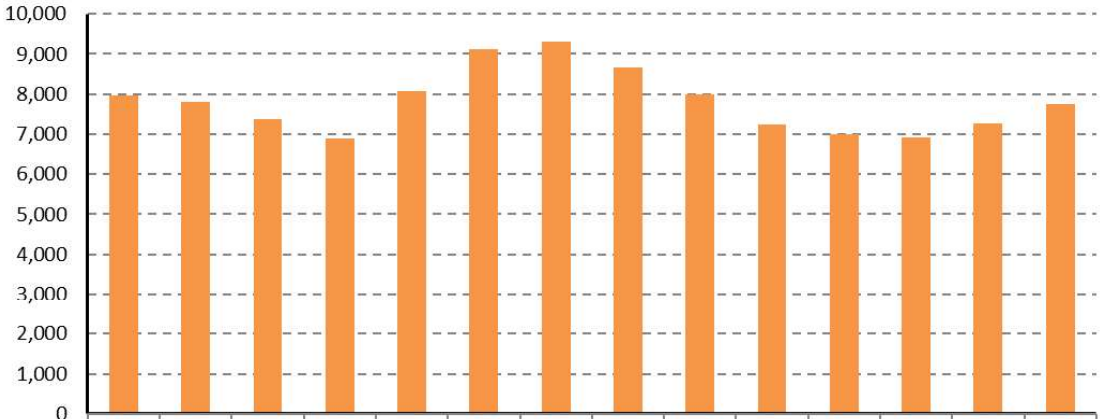
The PSC obligation forecasts developed by the ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load forecasts, it is expected that the historically embedded amount of conservation acquired will continue at the same rate going forward across the study period.

Firm Loads

The federal system total firm load forecast shows a 0.24 percent average annual load growth over this study period. While Bonneville's forecast of PSC requirement loads increased roughly 8 percent over the study period, Bonneville's Exports and Intra-Regional Transfers significantly decreased (almost 40%) due to the expiration of contracts. Other Contract Obligations that expire this time include Federal system power sales and Federal system capacity sales.

Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While on an annual basis these obligations demonstrate little variation across the study period, Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[7] experiences its highest loads in the late fall and winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer and early fall months when temperatures are mild. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecasted Federal system firm load obligations for OY2025.

Table 2-2 Federal System Firm Obligations for OY2025 - Monthly



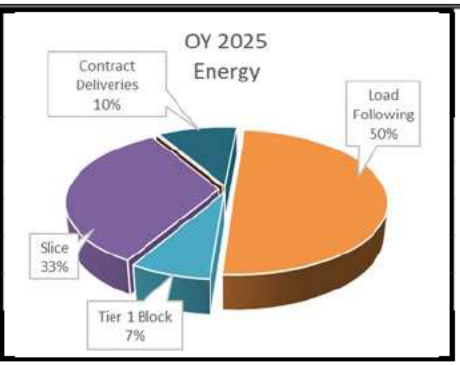
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7961	7810	7365	6892	8076	9131	9300	8658	8000	7230	7005	6908	7277	7756

Table 2-3 shows the annual Federal system firm load obligations for OY2025 in Energy aMW.

[7] This is reflective of Bonneville's total aggregate loads, individual customers highest loads vary by month and season.

Table 2-3 Federal System Annual Firm Obligations by Category OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Load Following	3,914	50%
Tier One Block	570	7%
Slice	2,595	33%
DSI	11	0%
Contract Deliveries	772	10%
Total Firm Obligations	**7,861**	**100%**



As previously noted, RD contracts expire at the end of FY2028, and negotiations for new 19-year Provider of Choice (PoC) PSCs are ongoing with contracts expected to be executed in December 2025. Given the uncertainty around post-2028 obligation levels, this study assumes a continuation of RD PSC load levels for planning purposes.

Resources

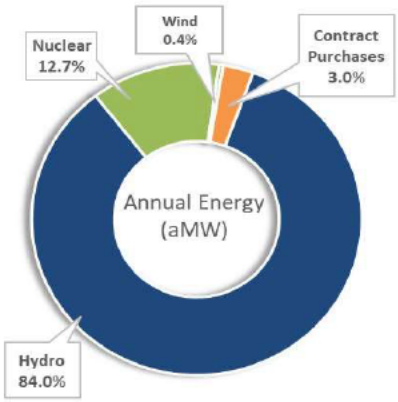
In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By Statute, Bonneville does not own generating resources, but instead, Bonneville markets power from Federal resources and non-Federal generating resources whose output Bonneville has acquired under contract. These resources and contract purchases are collectively referred to as "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources (wind projects); 3) Thermal resources, (Columbia Generating Station); and 4) Contract purchases, which are purchases from entities within the PNW region as Intra-Regional Transfers (In), including the Mid-C Non-Federal Canadian Entitlement Return power and from those outside of the PNW region as Imports.

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY2025, Federal system resources are forecast to produce 7,602 annual aMW of generation under Firm water conditions, after reserves and losses are included.

Table 2-5 Federal System Generations by Resource Type for OY2025 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,589	84%
Nuclear	994	12.7%
Wind	33	0.4%
Contract Purchases	233	3%
Total Federal Resources	7,849	100%
Reserves & losses	-247	--
Total Net Resources	7,602	--



Federal system contract purchases

Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region as Intra-Regional Transfers (In) and from outside the region as Imports, to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases; 2) power or energy exchange purchases; 3) power assigned to Bonneville under Treaty-related agreements; and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contract, and these returns are treated as Federal system resources. Except for deliveries from Treaty-related contracts and transmission loss return of Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed. Treaty-related and Slice/Block contracts are assumed to remain in place through this study horizon.

The Federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 details the Federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally, it shows the variability of individual Federal system hydro project generation for the three water conditions: firm, median, and high.
- Federal system non-hydro resources: Federal system non-hydro resources are generating resources whose output has been purchased by Bonneville. Table 2-7 details these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year but may change annually based on scheduling of annual maintenance, refueling, and capital improvements.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-141b:
2024 Bonneville White Book

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[8] – OY2025

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity d/ (MW)	High c/ Energy (aMW)	Median c/ Energy (aMW)	Firm Energy a/c/ (aMW)	
Regulated Hydro								
1. Albeni Falls	1955	USACE	3	50	21.5	25.8	25.3	
2. Dworshak	1974	USACE	3	465	304	193	155	
3. Hungry Horse	1952	USBR	4	310	129	94	88	
4. Libby	1975	USACE	5	605	280	236	193	
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,063	2,306	1,872	
	1973		6	314				
6. Chief Joseph	1955	USACE	27	2,614	1,780	1,372	1,106	
7. Lower Granite	1975	USACE	6	930	295	190	139	Lower Snake River Projects
8. Little Goose	1970	USACE	6	930	312	207	155	
9. Lower Monumental	1969	USACE	6	930	297	203	147	
10. Ice Harbor	1961	USACE	6	693	260	190	144	
11. McNary	1953	USACE	14	1,120	626	545	451	Lower Columbia River Projects
12. John Day	1968	USACE	16	2,480	1,374	994	787	
13. The Dalles	1957	USACE	22	2,080	1,081	817	642	
14. Bonneville b/	1938	USACE	18	1,221	722	527	387	
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,546**	**7,901**	**6,291**	
Independent Hydro Projects								
16. Anderson Ranch	1950	USBR	2	40	16	12	13	
17. Big Cliff	1954	USACE	1	21	14	11	11	
18. Black Canyon	1925	USBR	2	8.5	8	6	7	
19. Boise Diversion	1908	USBR	3	2.5	1	1	1	
20. Chandler	1956	USBR	2	12.2	9	7	6	
21. Cougar	1964	USACE	2	28	9	5	5	
22. Cowlitz Falls	1994	LCPD#1	2	70	33	29	29	
23. Detroit	1953	USACE	2	115	33	26	23	
24. Dexter	1955	USACE	1	17	10	8	8	
25. Foster	1968	USACE	2	23	10	8	8	
26. Green Peter	1967	USACE	2	92	22	16	16	
27. Green Springs	1960	USBR	1	18	7	7	7	
28. Hills Creek	1962	USACE	2	34	24	19	17	
29. Lookout Point	1954	USACE	3	138	17	15	20	
30. Lost Creek	1975	USACE	2	56	42	37	31	
31. Minidoka	1909	USBR	4	28	19	14	11	
32. Palisades	1957	USBR	4	177	100	92	77	
33. Roza	1958	USBR	1	14	9	8	6	
34. Total Independent Hydro Projects			**38**	**894**	**381**	**320**	**296**	
Small Non-Federally Owned Hydro Projects								
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6	
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3	
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**	
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,930**	**8,223**	**6,589**	

a/ Firm energy is the 12-month annual average for OY 2025 assuming 10th percentile (P10) water conditions

b/ Bonneville Dam generation totals include Bonneville Fishway

c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile

d/ Maximum Capacity represent full capacity of resource including overload.

[8] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY2025

	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	994
2	Stateline Wind Project [b/]	2001	Wind	PPM, FLP	0	21 2
3	Klondike Phase III [c/]	2007	Wind	NW Wind Power	0	11 8
4	Fourmile Hill Geothermal [d/]	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,027**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				237	135
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	69
10	Slice Transmission Loss Return				41	28
11	**Total Federal System Contract Purchases**				**454**	**233**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,632**	**1,259**

a/ This is the maximum generation for January 2025
b/ Stateline Wind Project contract expiring in 2028
c/ Klondike Phase III Project expiring in 2029
d/ Fourmile Hill is not assumed to be in operation within the study period

Federal System Hydro Generation Variability

The generating capacity of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, a combination of other power and non-power constraints, and other operating limitations. Table 2-8 shows the annual variability of hydro generation under the three water conditions. Although hydro generation changes drastically from different water conditions, within each condition, however, it changes only slightly from year to year.

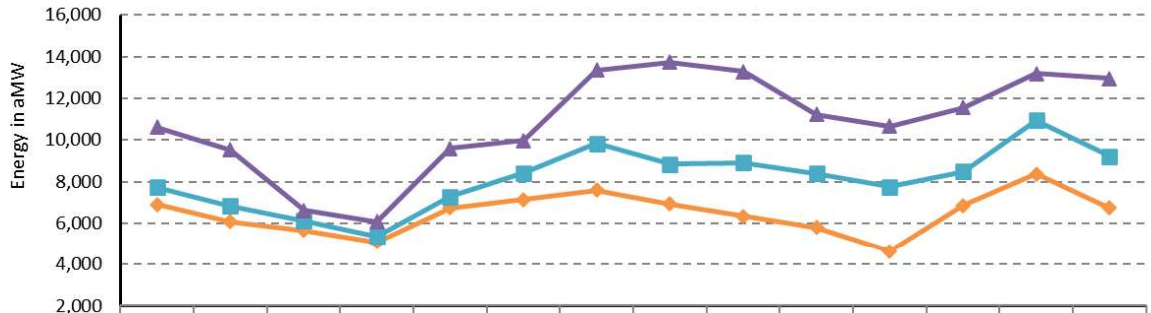
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY2025 – OY2034

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	6,589	6,536	6,614	6,544	6,628	6,633	6,633	6,642	6,623	6,688
Median Water (p50)	8,223	8,237	8,244	8,250	8,274	8,294	8,294	8,307	8,286	8,419
High Water (p90)	10,930	10,825	10,911	10,799	10,952	10,963	10,966	10,996	10,965	11,146

In OY2025, annual Federal system hydro energy generation is forecasted to be 6,589 aMW under Firm Water conditions. However, under the High Water conditions these same Federal system hydro

resources could generate as much as 10,930 aMW for OY2025. Table 2-9 displays the monthly variability of the Federal system hydro generation forecasted for OY2025, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood control and power production. The available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has minimal impact on generation from the Federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by close to 7,000 aMW in a single month, almost double in this case March, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2025

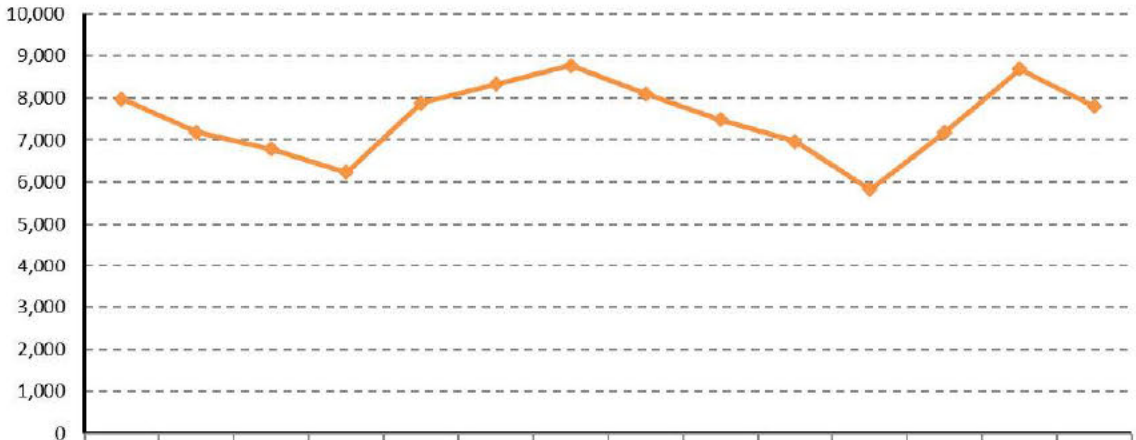


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,905	6,077	5,649	5,072	6,731	7,148	7,586	6,928	6,333	5,800	4,635	6,856	8,360	6,732
Median Water (P50)	7,727	6,835	6,121	5,357	7,284	8,416	9,840	8,830	8,904	8,395	7,748	8,484	10,931	9,220
High Water (P90)	10,620	9,522	6,620	6,070	9,601	9,962	13,355	13,732	13,291	11,224	10,652	11,567	13,185	12,956

Total Federal System Resources

Table 2-10 shows the monthly shape of forecasted total Federal system generation for energy (in aMW) for OY2025, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources, as well as contract purchases. Overall, the Federal system maintains similar monthly shapes over the study period, with the highest generation forecasted in late fall and winter (Nov-March) and mid-summer periods.

Table 2-10 Federal System Monthly Generation for OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7982	7190	6790	6238	7885	8326	8768	8099	7486	6968	5828	7192	8692	7801

Key Results

Annual Energy

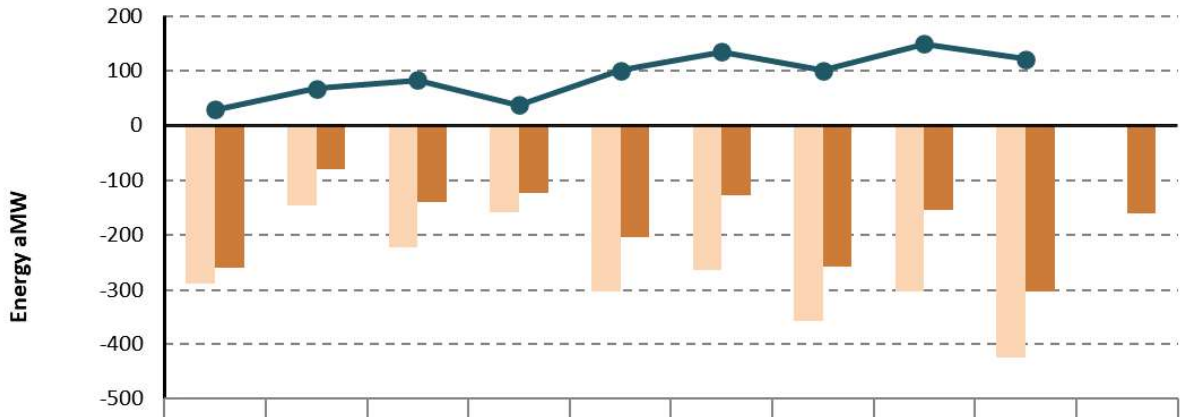
Table 2-11 shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY2025 through OY2034. The Federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY2025.

Table 2-11 Federal System Annual Energy Surplus/Deficit under Firm Water Conditions

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficits	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

Table 2-12 compares the 2024 White Book Federal system annual firm energy surplus/deficit results to those from the 2023 White Book. Compared with the previous White Book, the 2024 White Book shows a slight decrease in deficits annually throughout the studying period. These results reflect changes in both load obligations and Federal system generation.

Table 2-12 Federal System Annual Energy Surplus/Deficits Comparison under Firm Water



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	-289	-147	-223	-159	-303	-263	-357	-303	-424	
2024 White Book	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161
Delta	29	67	83	37	100	134	100	149	121	

Federal System Annual Surplus/ Deficit

Table 2-13 graphically presents the annual firm energy surplus/deficits. Over the study period, the Federal system is forecasted to have a deficit in annual firm energy as high as 303 aMW near the end of the study period. Some differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) maintenance schedule[9].

Table 2-13 Federal System Annual Surplus/ Deficits Under Firm Water Conditions

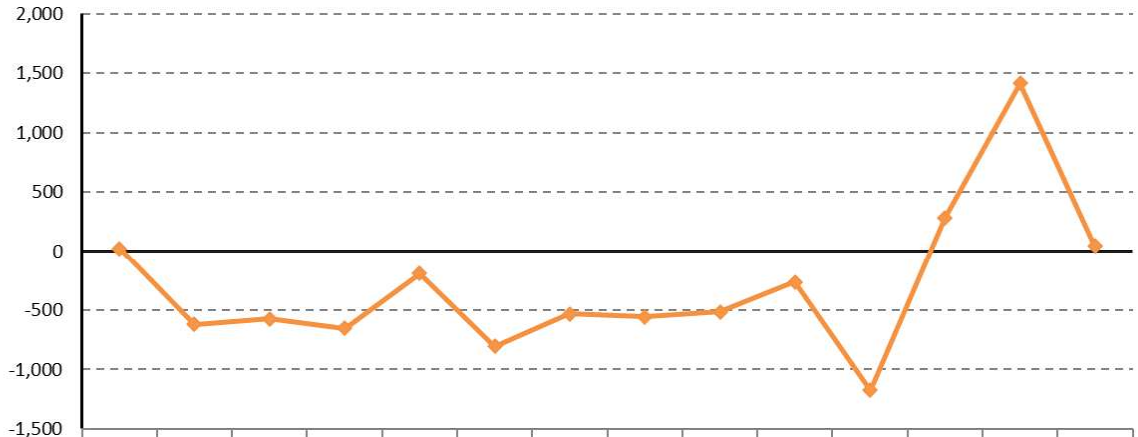
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

[9] CGS has routine maintenance cycle scheduled in odd calendar years, specifically in months of May and June. CGS is forecast to produce 994 aMW annually during maintenance years, and 1,116 aMW annually during non-maintenance years.

Federal System Monthly Surplus/ Deficit

Table 2-14 displays a graphic look at the Federal system monthly firm energy surplus/deficits for OY2025. Both forecasts maintain similar monthly shapes over the other Operating Years in this study period. With highest deficits comes in the second half of April and better positions come in May, June, and July.

Table 2-14 Federal System Monthly Surplus/ Deficits OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	22	-620	-575	-654	-191	-805	-531	-559	-513	-262	-1177	284	1415	45

Conclusion

Under Firm water conditions, the Federal system shows annual firm energy deficits through the 2025-2034 study period. These annual energy deficits range from 79 aMW in OY2026 to as high as 303 aMW in OY2032. At a monthly resolution under Firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The Federal system surplus/deficit forecasts generally have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by close to 7,000 aMW within the same year.

The range of Federal system monthly surplus and deficit forecasts under all 30-water years is presented in Exhibit 4-3. Additional monthly and annual details for OY2025 through OY2034 are available upon request, a list of available data reports can be found in the Appendix. Reminder: Data Report requests can be received via email to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2025 through OY 2034. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resources forecasts incorporate annual regional utility data submittals received by Bonneville.

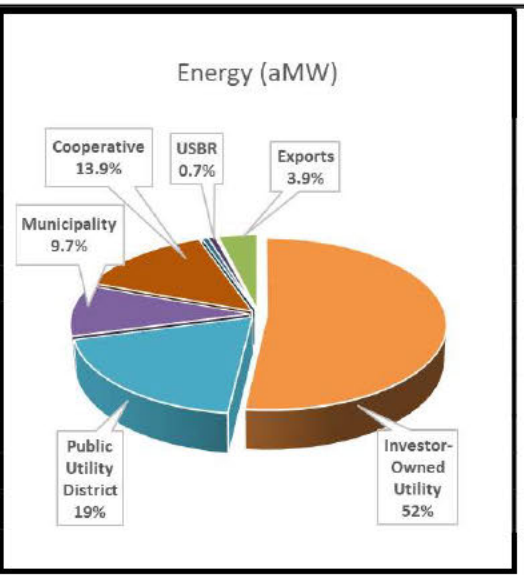
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historical conservation savings, and do not include specific adjustments for future climate change impacts. Apart from power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration dates. Treaty power deliveries are assumed to be in place through the study period. The sum of the forecasted TRL and Export contracts represent the regional loads for the PNW.

Regional loads are comprised of roughly 96 percent retail loads and four percent exports. Table 3-1 shows the forecasted composition of PNW regional load for OY2025.

Table 3-1 PNW Region Firm Loads by Customer Class – OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,566	52%
Public Utility District	4,963	19%
Municipality	2,545	9.7%
Cooperative	3,642	13.9%
Federal Agency	160	1%
USBR	186	0.7%
DSI	53	0.2%
Marketer	0	0.0%
Total Retail Load	**25,115**	**96%**
Exports	1,030	3.9%
Total Regional Load	**26,145**	**100%**



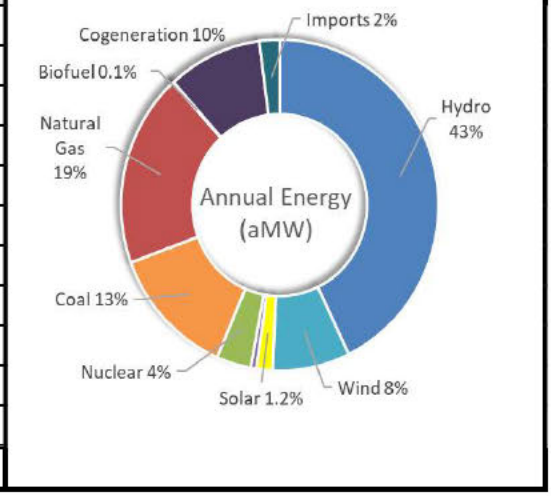
Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Similarly to the Federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) non-hydro renewable resources which include wind, solar, and other projects; 3) Thermal resources which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases which are identified as Imports.

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Regional resource forecasts assume the retirement of the following coal projects over the study period: Centralia 2 (December 1, 2025) and Valmy 2 (January 1, 2026). Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY2025 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,196	43%
Wind	2,238	8%
Solar	479	1.7%
Other Renewable	158	0.6%
Nuclear	994	3%
Coal	3,676	13%
Natural Gas	5,372	19%
Petroleum	0	0%
Biofuel	26	0.1%
Cogeneration	2,728	10%
Imports	591	2%
Total Regional Resources	**28,457**	**100%**



Regional Hydro Generation Variability

The generating capacity of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to the Federal hydro resources, Bonneville utilizes the 30-year streamflow record and percentile of T1SFCO results for planning purposes. Again, three water conditions are presented here to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three streamflow scenarios. Details on the different streamflow scenarios please refer to Hydro Resource Modeling section.

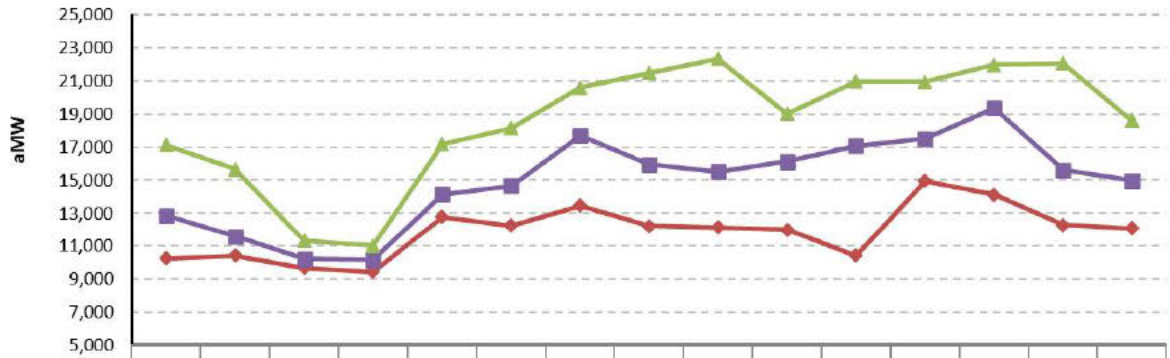
In OY2025, annual firm energy generation from regional hydro projects is forecasted to be 12,196 aMW under the firm water conditions, and this represents about 43% percent of the region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW between firm and high water conditions.

Table 3-4 PNW Regional Annual Variability of Hydro Generation by Streamflow Conditions

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	12,196	11,888	12,201	11,958	12,212	12,216	12,216	12,225	12,149	12,238
Median Water (p50)	14,729	14,807	14,727	14,820	14,756	14,786	14,786	14,800	14,819	14,932
High Water (p90)	18,817	18,751	18,854	18,708	18,885	18,893	18,922	18,957	18,929	19,110

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2025. The increased level of generation in January through March period is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early full as streamflow are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through November. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions within the same month.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions - OY2025



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,268	10,424	9,680	9,468	12,772	12,264	13,459	12,220	12,157	12,010	10,436	14,953	14,121	12,294	12,081
Median Water (P50)	12,868	11,591	10,237	10,180	14,150	14,681	17,712	15,952	15,523	16,130	17,067	17,499	19,372	15,600	14,970
High Water (P90)	17,128	15,680	11,353	11,036	17,178	18,161	20,582	21,478	22,334	19,026	20,956	20,936	21,970	22,056	18,617

Uncommitted IPP Generation Delivered to the PNW Region

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources, that are not committed to serving specific loads represent approximately 2,793 aMW of energy for OY2025. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY2025 through OY2034 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Energy (aMW)	2,793	2,790	2,629	2,546	2,586	2,592	2,592	2,592	2,591	2,601

Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect those changes.

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY2025 Firm Water Conditions

Project	Fuel Type	Energy (aMW)	Peak (MW)
Airport Solar	Solar	13	0
Centralia Complex [a/b/]	Coal	260	290
Condon Wind	Wind	12	0
Cosmopolis Specialty Fibres	Wood Waste	14	14
Hermiston Power Project	Wood Waste	567	630
International Paper Energy Center	Wood Waste	17	22
Juniper Canyon Wind	Wind	36	0
Kittitas Valley Wind	Wind	24	0
Klamath Generation Facility	Natural Gas	436	484
Klamath Generation Peakings (CT)	Natural Gas	90	100
Klondike Wind 1	Wind	6	0
Klondike Wind 3	Wind	23	0
Klondike Wind 3a	Wind	18	0
Leaning Juniper Wind	Wind	47	0
Longview Fibre Paper & Packaging	Wood Waste	35	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	0	6
Pelton	Hydro	14	41
Priest Rapids	Hydro	85	154
Rock Island	Hydro	168	154
Rocky Reach	Hydro	155	339
Round Butte	Hydro	31	99
Satsop Combustion Turbine Project	Natural Gas	584	650
SDS Lumber	Wood Waste	1	1
Smith Creek (Idaho)	Hydro	7	0

Project	Fuel Type	Energy (aMW)	Peak (MW)
Stateline Wind	Wind	8	0
Stimson Lumber (Plummer)	Wood Waste	44	7
Tacoma Biomass (WestRock)	Wood Waste	0	0
Tieton Dam (Yakima)	Hydro	0	0
Vansycle Wind	Wind	23	0
Wanapum	Hydro	25	60
Weyerhaeuser Longview	Wood Waste	35	44
Willow Creek Wind	Wind	16	0
Total Uncommitted IPP Generation		**2,793**	**3,129**

[a/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025. Puget purchased an increasing amount of this project beginning Dec 1, 2014 and ending Nov 30, 2025.

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,793 aMW in OY2025) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY2025 through OY2034 are shown in Exhibit 5-1, and OY2025 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY2025 through OY2034 are available upon request via email at WhiteBook@bpa.gov.

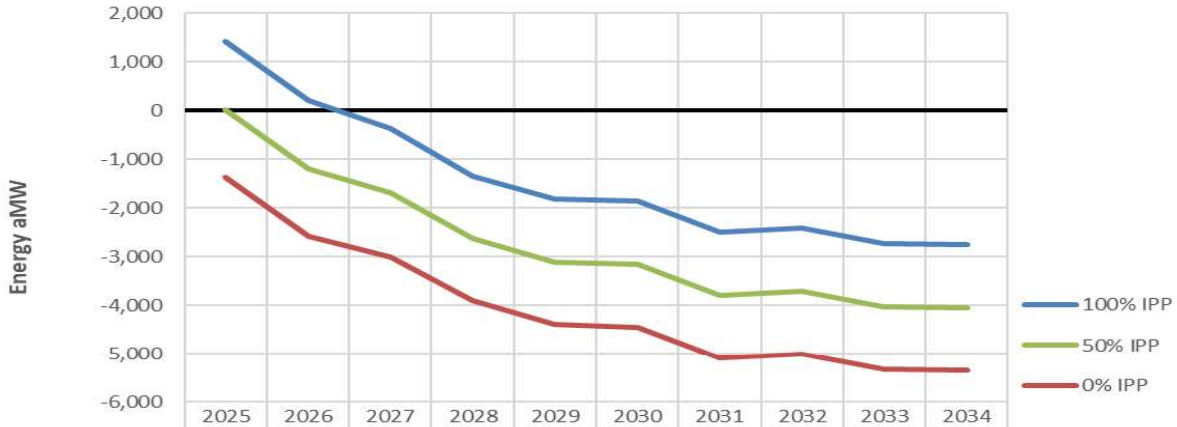
Table 3-8 PNW Regional Annual Energy Surplus/ Deficit - Firm Water Conditions

Assuming 100% of Uncommitted IPP Generation is Available to the Region

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficit	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

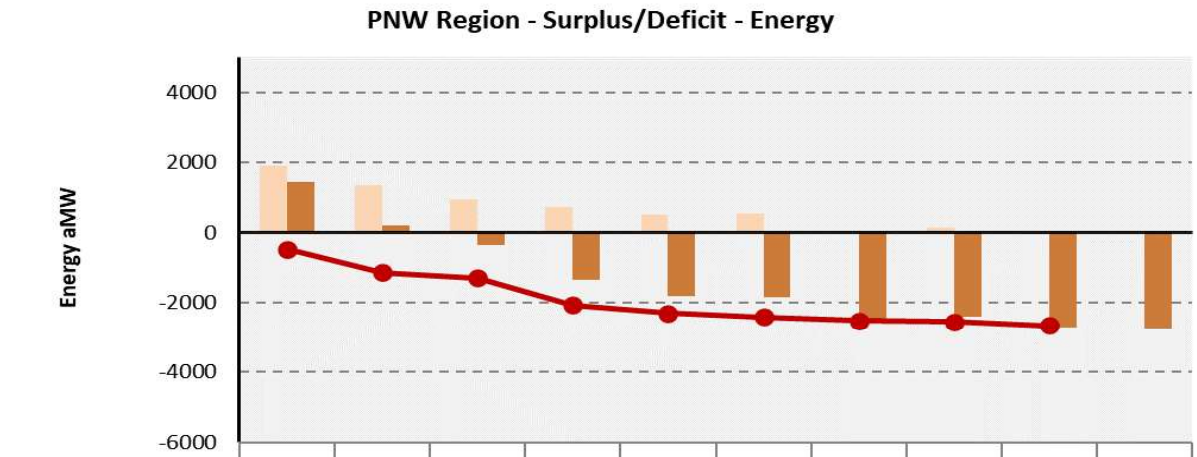
Table 3-9 PNW Regional Annual Energy Surplus/ Deficit by Uncommitted IPP Generation %



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
100% IPP	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738
50% IPP	29	-1,189	-1,684	-2,625	-3,101	-3,158	-3,788	-3,703	-4,020	-4,038
0% IPP	-1,367	-2,584	-2,999	-3,898	-4,393	-4,454	-5,085	-4,999	-5,316	-5,339

Table 3-10 compares the 2024 White Book PNW regional annual firm energy surplus/ deficit forecasts to that of the 2023 White Book. Immediately, the comparison results show significant differences where OY2025 is less surplus in this study, and the difference gets more pronounced beginning in OY2026 and extends out all outyears where surplus became large deficits. This change is mainly driven by an increase in the PNW Regional Retail Load, more specifically in the new large industrial loads.

Table 3-10 PNW Regional Annual Surplus/ Deficit Comparison – Firm Water Conditions Assuming 100% Uncommitted IPP Generations available to the Region



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	1905	1357	932	728	509	553	40	144	-61	
2024 White Book	1426	207	-370	-1352	-1808	-1861	-2492	-2407	-2725	-2738
Delta	-479	-1150	-1302	-2080	-2317	-2414	-2533	-2551	-2664	

Regional Annual Surplus/ Deficit

Table 3-11 graphically presents the annual firm energy surplus/ deficit forecasts for the PNW region. These forecasts assume 100 percent availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/ deficit declines over the 10-year study period.

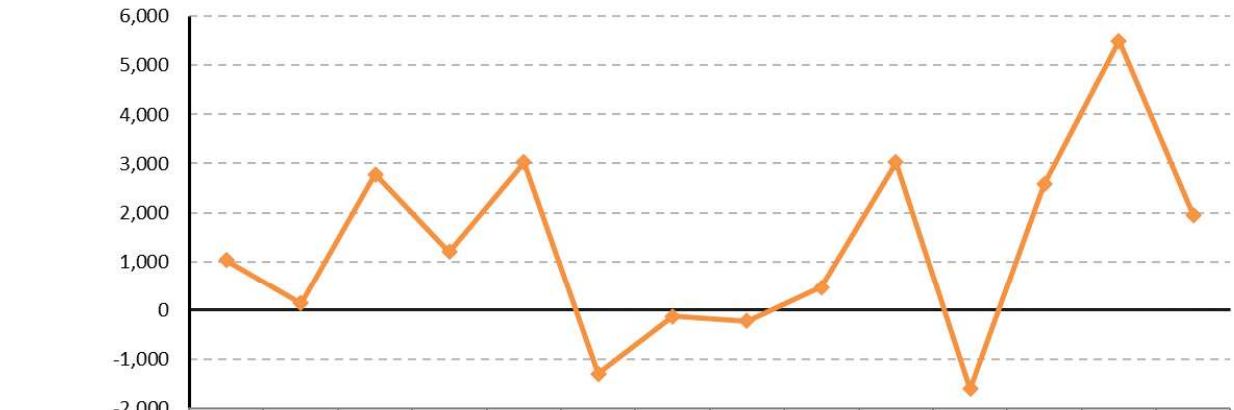
Table 3-11 PNW Regional Annual Surplus/ Deficit – Firm Water Conditions

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

Regional Monthly Surplus/ Deficit

Table 3-12 shows the monthly energy surplus/ deficit forecast for OY2025. Again, these forecasts assume 100 percent of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to beginning of summer, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin.

Table 3-12 PNW Regional Monthly Surplus/ Deficit – OY2025 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	1,032	143	2,784	1,203	3,027	-1,300	-122	-224	464	3,026	-1,600	2,584	5,496	1,953

Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years then surpluses sharply declined and quickly becoming deficits, then continued with larger deficits going into the outyears, under the assumption of 100 percent of the PNW region's uncommitted IPP generation available to serve the region's load. Additionally, due to the fact that 100 percent of the uncommitted IPP generation is assumed to be available to serve the region's load, with its uncommitted nature, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly.

Detailed surplus/deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-3; monthly and annual details for OY2025 through OY2034 are available upon request with the itemized list located in the Appendix.

The regional energy and capacity deficits identified in this study may be mitigated through resource options discussed in the NWPCC's Power Plan publications, NWPCC is currently working on updating their 2021 Northwest Power Plan[10] and it is updated roughly every 5-year. Bonneville provides this PNW regional planning analysis for informational purposes only.

[10] The 2021 Northwest Power Plan (nwcouncil.org)

SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/ Deficit:

Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/7/2024**

S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Firm Obligations										
1	**Load Following**	3914	3981	4024	4058	4096	4136	4160	4173	4196	4214
2	Preference Customers	3578	3639	3680	3712	3747	3786	3809	3823	3844	3862
3	Federal Agencies	150	156	158	160	163	164	165	165	165	166
4	USBR	186	186	186	185	186	186	186	185	186	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	570	569	570	568	569	568	569	567	568	567
7	Tier 1 Block	570	569	570	568	569	568	569	567	568	567
8	**Slice**	2595	2591	2591	2586	2590	2604	2590	2602	2591	2615
9	Slice Block	1227	1210	1221	1208	1219	1207	1217	1204	1220	1208
10	Slice Output from T1 System	1368	1381	1370	1378	1371	1396	1373	1398	1371	1407
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	772	591	490	478	479	475	473	473	473	473
14	Exports	477	468	468	468	468	464	464	464	464	464
15	Intra-Regional Transfers (Out)	295	123	22.4	10.7	10.7	10.7	9.44	9.44	9.44	9.44
16	**Total Firm Obligations**	**7861**	**7743**	**7686**	**7702**	**7745**	**7793**	**7803**	**7827**	**7839**	**7880**
	Net Resources										
17	**Hydro**	6589	6536	6614	6544	6628	6633	6633	6642	6623	6688
18	Regulated Hydro - Net	6291	6258	6313	6264	6342	6349	6349	6361	6371	6433
19	Independent Hydro - Net	296	275	298	277	283	281	281	278	249	252
20	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88
21	**Non-Hydro Renewable**	33.0	33.0	19.8	1.90	0	0	0	0	0	0
22	Wind - Net	33.0	33.0	19.8	1.90	0	0	0	0	0	0
23	Other - Net	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	994	1116	994	1116	994	1116	994	1116	994	1116
25	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
26	**Contract Purchases**	233	227	164	164	164	165	164	165	164	165
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
28	Intra-Regional Transfers (In)	68.6	63.0	0	0	0	0	0	0	0	0
29	Non-Federal CER	135	135	135	135	135	135	135	135	135	135
30	Slice Transmission Loss Return	28.0	28.2	28.0	28.2	28.0	28.6	28.1	28.6	28.0	28.8
31	**Reserves & Losses**	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
35	**Total Net Resources**	**7602**	**7664**	**7546**	**7580**	**7541**	**7665**	**7546**	**7673**	**7536**	**7719**
36	**Total Surplus/Deficit**	**-260**	**-79.3**	**-139**	**-122**	**-203**	**-128**	**-257**	**-153**	**-303**	**-161**

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Exhibit 4-2: Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 Percentile: 10
White Book 2024 Report Date: **6/11/2024**
S251-WB-20240606-131030

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	3843	3845	3356	3422	3725	4520	4532	4186	3809	3716	3716	3679	3939	4231	3914
2	Preference Customers	3369	3373	2936	3163	3559	4336	4348	3988	3592	3344	3344	3209	3436	3659	3578
3	Federal Agencies	136	136	125	138	159	181	176	184	159	141	141	129	127	142	150
4	USBR	338	336	295	121	7.27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
7	Tier 1 Block	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
8	**Slice**	2506	2349	2285	2244	2768	3040	3108	2866	2635	2401	2176	2389	2626	2473	2595
9	Slice Block	1113	1113	1092	1128	1310	1502	1489	1373	1265	1164	1164	1117	1069	1106	1227
10	Slice Output from T1 System	1393	1235	1192	1117	1458	1537	1620	1493	1371	1237	1013	1272	1557	1366	1368
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	1222	1226	1078	693	695	694	696	696	692	693	693	692	692	714	772
14	Exports	644	649	508	454	454	454	454	454	454	454	454	454	454	477	477
15	Intra-Regional Transfers (Out)	578	578	570	238	241	240	241	242	237	238	238	237	237	237	295
16	**Total Firm Obligations**	**7961**	**7810**	**7365**	**6892**	**8076**	**9131**	**9300**	**8658**	**8000**	**7230**	**7005**	**6908**	**7277**	**7756**	**7861**
	Net Resources															
17	**Hydro**	6905	6077	5649	5072	6731	7148	7586	6928	6333	5800	4635	6856	8360	6732	6589
18	Regulated Hydro - Net	6558	5744	5356	4805	6462	6981	7295	6685	6130	5522	4424	6438	7889	6358	6291
19	Independent Hydro - Net	344	330	291	265	267	164	288	241	201	274	208	416	469	372	296
20	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
21	**Non-Hydro Renewable**	22.6	33.8	31 5	25.3	36 2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
22	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
23	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
26	**Contract Purchases**	202	200	213	226	256	303	335	292	251	228	223	164	165	166	233
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
28	Intra-Regional Transfers (In)	34.7	35.0	57.0	64.5	88.9	138	164	125	89.0	64.4	64.4	0	0	0	69
29	Non-Federal CER	137	138	131	138	137	132	137	135	133	137	137	137	132	137	135
30	Slice Transmission Loss Return	29.0	25.7	24.2	22.7	29.6	31 2	32.9	30.3	27.9	25.1	20.6	25.9	32.4	28.4	28
31	**Reserves & Losses**	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
35	**Total Net Resources**	**7982**	**7190**	**6790**	**6238**	**7885**	**8326**	**8768**	**8099**	**7486**	**6968**	**5828**	**7192**	**8692**	**7801**	**7602**
36	**Total Surplus/Deficit**	**22**	**-620**	**-575**	**-654**	**-191**	**-805**	**-531**	**-559**	**-513**	**-262**	**-1,177**	**284**	**1,415**	**45**	**-260**

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Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025

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Federal Report Surplus Deficit By Water Year

Operating Year 2025

White Book 2024 Report Date: **6/12/2024**

S251-WB-20240606-131030

Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1 1989 Federal Report Surplus Deficit	165	720	-595	-750	-89.4	-61.7	-379	-1582	1010	1762	1538	1897	1096	579	281
2 1990 Federal Report Surplus Deficit	263	-323	-322	-375	363	1250	1386	2959	1050	1757	1832	1135	4061	3543	1387
3 1991 Federal Report Surplus Deficit	2448	1783	10.3	-557	2156	1325	2885	3853	2345	2527	1264	1529	3433	3947	2065
4 1992 Federal Report Surplus Deficit	2923	1505	-384	-446	184	-1251	-345	69.6	-513	361	-1177	662	2044	-262	127
5 1993 Federal Report Surplus Deficit	295	-354	-345	-657	5.21	-799	-934	-1812	45.9	-175	-1243	2052	1852	1905	60.5
6 1994 Federal Report Surplus Deficit	880	59.0	3.11	-452	122	-749	-1008	-386	-550	-473	161	284	1945	367	-12.4
7 1995 Federal Report Surplus Deficit	249	-600	-207	-532	-87.3	-438	8.22	926	2561	248	-192	1078	3358	2160	719
8 1996 Federal Report Surplus Deficit	1481	373	184	658	2864	5213	5859	5939	5958	2553	3179	2580	5048	4715	3555
9 1997 Federal Report Surplus Deficit	2666	2075	290	-97.3	899	1390	5700	6078	4929	4079	4884	5676	6092	4905	3544
10 1998 Federal Report Surplus Deficit	3102	2699	1029	2053	1696	343	1227	2280	1102	105	-4.86	4008	3881	2471	1919
11 1999 Federal Report Surplus Deficit	2786	1240	6.38	-350	-280	763	3971	3461	4916	2123	2643	1608	4099	5309	2321
12 2000 Federal Report Surplus Deficit	4177	3353	271	123	2224	1826	2389	2447	2242	2097	2603	1802	1415	2016	1904
13 2001 Federal Report Surplus Deficit	2052	-461	-252	-415	-179	-944	-867	-204	-627	-1133	-1752	-445	325	-79.1	-366
14 2002 Federal Report Surplus Deficit	557	-509	-598	-771	-385	-172	-435	-84.5	-39.2	1704	1407	1146	4371	3370	664
15 2003 Federal Report Surplus Deficit	519	-200	-168	-422	241	-805	-531	207	1592	483	1011	750	3312	321	445
16 2004 Federal Report Surplus Deficit	-362	-673	-528	-584	648	-274	-148	-559	-2.77	302	522	573	2791	685	207
17 2005 Federal Report Surplus Deficit	-44.5	188	125	226	680	554	960	2200	293	-592	-204	601	1808	1387	699
18 2006 Federal Report Surplus Deficit	544	-449	-317	-654	705	349	2848	3649	1492	3081	1861	3573	3579	1703	1603
19 2007 Federal Report Surplus Deficit	657	-344	-435	-477	294	394	2250	1216	3538	3638	888	1390	1993	1514	1174
20 2008 Federal Report Surplus Deficit	351	-578	-575	-585	415	-9.96	97.8	169	395	564	-827	2244	4735	3026	806
21 2009 Federal Report Surplus Deficit	1255	1256	-18.7	-383	371	-556	1621	457	-206	1863	1249	1324	1745	1098	688
22 2010 Federal Report Surplus Deficit	21.7	-873	-378	-389	-90.5	-972	-313	-625	-775	-262	-1313	-25.7	3907	1988	91.3
23 2011 Federal Report Surplus Deficit	664	-145	-21.6	-528	-191	896	4049	4813	2755	3971	1251	2374	6134	6497	2454
24 2012 Federal Report Surplus Deficit	3584	1513	17.1	0.97	155	212	2372	2598	2441	4420	4363	2745	5182	5513	2342
25 2013 Federal Report Surplus Deficit	2864	2070	-93.9	-377	1352	1961	1074	842	334	3563	1801	1949	3797	2054	1503
26 2014 Federal Report Surplus Deficit	1212	-28.0	72.3	-248	111	-40.0	1675	32.9	3464	2974	1486	1986	3422	3352	1396
27 2015 Federal Report Surplus Deficit	1262	21.4	17.5	-481	1229	1317	2831	3756	4315	1596	-324	-201	834	-364	1194
28 2016 Federal Report Surplus Deficit	105	-664	-666	-432	155	-194	47.7	102	3280	3495	3518	1554	1835	45.4	745
29 2017 Federal Report Surplus Deficit	16.1	-620	-268	-108	2049	948	3132	3986	6193	5323	4112	3960	5272	2052	2620
30 2018 Federal Report Surplus Deficit	1872	565	-292	-523	-602	184	3432	4752	2782	2508	1859	4957	3734	1141	1896

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SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/ Deficit: Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Regional Loads										
1	**Retail Loads**	25115	25734	26358	27131	27747	27984	28140	28242	28451	28587
2	Federal Agency	160	166	168	170	172	173	173	173	174	174
3	USBR	186	186	186	185	186	186	186	185	186	186
4	Cooperative	3642	4156	4666	5329	5791	5912	5960	5979	6055	6100
5	Municipality	2545	2546	2545	2547	2551	2555	2562	2558	2567	2571
6	Public Utility District	4963	5011	5068	5116	5181	5242	5289	5324	5374	5406
7	Investor-Owned Utility	13566	13617	13673	13730	13813	13864	13917	13968	14042	14096
8	Direct-Service Industry	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	1030	1021	1021	1020	1019	1013	765	670	670	670
11	Canada	468	468	468	468	468	464	464	464	464	464
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	561	552	552	552	550	548	300	205	205	205
14	**Total Regional Loads**	**26145**	**26755**	**27379**	**28151**	**28765**	**28997**	**28905**	**28911**	**29121**	**29256**
	Regional Resources										
15	**Hydro**	12196	11888	12201	11958	12212	12216	12216	12225	12149	12238
16	Regulated Hydro - Net	11030	10763	11026	10832	11029	11034	11034	11044	10974	11076
17	Independent Hydro - Net	922	881	931	883	939	939	939	938	932	919
18	Small Hydro - Net	244	244	244	243	244	244	244	243	244	244
19	**Non-Hydro Renewable**	2875	2902	2902	2901	2903	2902	2886	2897	2902	2902
20	Wind - Net	2238	2238	2238	2236	2238	2238	2222	2233	2238	2238
21	Solar - Net	479	508	508	507	508	508	508	507	508	508
22	Other - Net	158	157	157	158	158	157	157	157	157	157
23	**Thermal**	12796	12444	12176	12198	12103	12280	12029	12198	12158	12195
24	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
25	Coal - Net	3676	3201	3049	2955	2981	3034	2948	2962	3034	2948
26	Natural Gas - Net	5372	5371	5371	5373	5372	5368	5371	5372	5371	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2728	2730	2737	2729	2730	2737	2691	2722	2734	2734
30	**Imports**	591	595	599	603	607	610	130	36.5	36.4	36.4
31	Canada	38.8	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4
32	Inland Southwest	506	509	513	517	521	525	93.6	0	0	0
33	Pacific Southwest	47.1	47.1	47.1	47.1	47.1	47.1	0	0	0	0
34	**Reserves & Losses**	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
38	**Total Regional Resources**	**27571**	**26962**	**27009**	**26799**	**26958**	**27136**	**26412**	**26504**	**26396**	**26518**
39	**Total Surplus/Deficit**	**1426**	**207**	**-370**	**-1352**	**-1808**	**-1861**	**-2492**	**-2407**	**-2725**	**-2738**

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Exhibit 5-2: Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile

Operating Year: 2025 Percentile: 10

White Book 2024 Report Date: **6/11/2024**

S251-WB-20240606-131030

Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Regional Loads															
1 **Retail Loads**	24827	24844	22311	23053	24979	28759	28248	27123	24977	23475	23475	23070	24606	25969	25115
2 Federal Agency	147	148	136	150	167	189	184	192	167	153	153	140	139	154	160
3 USBR	338	336	295	121	7 27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
4 Cooperative	3165	3167	2881	3487	3656	4087	4070	3886	3659	3583	3583	3573	3762	3894	3642
5 Municipality	2281	2284	2200	2382	2676	3096	3106	2946	2716	2448	2448	2220	2202	2290	2545
6 Public Utility District	4664	4668	4354	4498	5122	5857	5871	5582	5085	4730	4730	4474	4574	4765	4963
7 Investor-Owned Utility	14179	14189	12392	12362	13297	15473	14956	14449	13238	12277	12277	12269	13501	14385	13566
8 Direct-Service Industry	52.2	52.2	52.9	53.8	54.2	53 9	54.3	54.0	53.5	53.9	53.9	52.4	52.1	52.1	53
9 Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 **Exports**	1186	1361	1167	846	1003	873	679	825	880	1215	1102	1147	1192	1306	1030
11 Canada	589	593	454	454	454	454	454	454	454	454	454	454	454	477	468
12 East Continental Divide	1.00	1 00	1.00	1.00	1 00	1.00	1.00	1 00	1.00	1 00	1.00	1.00	1 00	1.00	1.0
13 Pacific Southwest	596	767	712	390	548	417	223	369	425	760	647	692	737	829	561
14 **Total Regional Loads**	**26013**	**26205**	**23478**	**23898**	**25982**	**29631**	**28927**	**27948**	**25857**	**24690**	**24578**	**24217**	**25798**	**27275**	**26145**
Regional Resources															
15 **Hydro**	11631	10145	10313	9577	12623	12376	13860	12109	11280	12153	9151	13884	16585	12258	12196
16 Regulated Hydro - Net	10309	8944	9277	8644	11686	11528	12810	11121	10273	11035	8014	12282	14797	10860	11030
17 Independent Hydro - Net	997	878	791	771	809	723	926	857	845	838	855	1200	1366	992	922
18 Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19 **Non-Hydro Renewable**	2348	3106	2800	2292	2868	2222	1431	2134	2521	4083	3553	3870	3935	3855	2875
20 Wind - Net	1592	2338	2160	1742	2428	1869	1046	1661	1895	3311	2799	3023	3046	2951	2238
21 Solar - Net	597	608	483	390	281	194	237	314	467	616	596	687	755	724	479
22 Other - Net	159	159	157	160	159	159	148	158	158	157	157	160	134	181	158
23 **Thermal**	13425	13433	13454	13530	13750	13843	13803	13738	12829	11885	10532	9375	11207	13423	12796
24 Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25 Coal - Net	3821	3822	3825	3826	3824	3828	3828	3827	3580	2989	2792	3202	3842	3824	3676
26 Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3381	4262	5587	5372
27 Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29 Cogeneration - Net	2879	2879	2833	2844	2933	2954	2920	2918	2301	2271	2171	2404	2669	2869	2728
30 **Imports**	586	586	514	484	671	773	608	608	511	458	458	506	663	715	591
31 Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27 0	39
32 Inland Sou hwest	565	565	498	462	452	488	458	473	448	428	428	477	624	688	506
33 Pacific Southwest	0	0	0	0	181	235	87.4	63.3	0	0	0	0	0	0	47
34 **Reserves & Losses**	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
35 Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36 Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37 Transmission Losses	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
38 **Total Regional Resources**	**27045**	**26347**	**26263**	**25102**	**29009**	**28331**	**28805**	**27725**	**26321**	**27716**	**22978**	**26801**	**31294**	**29229**	**27571**
39 **Total Surplus/Deficit**	**1,032**	**143**	**2,784**	**1,203**	**3,027**	**-1,300**	**-122**	**-224**	**464**	**3,026**	**-1,600**	**2,584**	**5,496**	**1,953**	**1426**

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Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025

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Regional Report Surplus Deficit By Water Year
Operating Year 2025
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1,113	2,481	2,207	958	3,232	475	-161	-1,949	3,336	6,643	5,604	5,716	4,685	3,262	2,494
2	1990 Regional Report Surplus Deficit	1,382	889	2,852	1,661	4,402	3,609	4,191	6,433	3,745	6,695	5,442	4,145	9,646	8,534	4,676
3	1991 Regional Report Surplus Deficit	5,236	4,663	3,377	1,625	8,218	3,391	5,888	8,450	6,127	7,974	4,018	5,115	8,629	9,858	5,941
4	1992 Regional Report Surplus Deficit	6,293	4,361	2,848	1,440	3,332	-1,485	-44	1,392	464	3,994	-1,600	2,369	4,504	933	1,846
5	1993 Regional Report Surplus Deficit	816	347	2,241	962	2,846	-1,354	-1,664	-2,176	1,621	2,898	-1,078	6,179	5,591	5,591	1,797
6	1994 Regional Report Surplus Deficit	2,908	1,474	3,402	1,523	2,967	-1,013	-1,483	59	816	1,901	2,329	2,584	5,060	2,301	1,704
7	1995 Regional Report Surplus Deficit	919	90	2,777	1,275	2,831	153	790	3,227	6,636	3,218	684	4,585	8,909	6,034	3,296
8	1996 Regional Report Surplus Deficit	4,135	2,043	3,693	3,845	9,510	10,638	11,355	12,937	12,891	8,755	8,925	7,319	11,370	10,834	8,829
9	1997 Regional Report Surplus Deficit	5,941	5,338	4,071	2,483	5,022	3,643	11,142	12,581	11,329	11,554	10,839	12,084	13,252	11,634	8,643
10	1998 Regional Report Surplus Deficit	7,189	6,676	5,977	7,313	6,865	1,839	3,538	5,466	4,128	3,772	1,924	9,320	9,824	6,841	5,906
11	1999 Regional Report Surplus Deficit	6,008	3,713	3,628	1,824	3,111	2,724	8,168	7,702	10,925	7,691	6,901	5,896	10,596	12,529	6,597
12	2000 Regional Report Surplus Deficit	9,000	7,826	4,056	2,872	8,154	4,806	5,168	5,680	5,577	7,626	7,169	5,610	5,496	5,820	5,748
13	2001 Regional Report Surplus Deficit	4,498	1,135	2,905	1,660	2,564	-1,590	-1,825	117	-17	1,270	-2,154	361	2,255	1,334	836
14	2002 Regional Report Surplus Deficit	1,244	140	1,763	989	1,989	205	14	894	1,678	6,537	4,537	4,307	10,342	8,546	3,076
15	2003 Regional Report Surplus Deficit	2,208	887	3,119	1,332	3,158	-1,300	-122	1,451	4,524	3,542	3,188	3,316	8,056	2,247	2,544
16	2004 Regional Report Surplus Deficit	-119	-92	2,266	1,526	4,043	203	181	-224	1,528	3,617	2,378	3,017	7,020	3,266	2,142
17	2005 Regional Report Surplus Deficit	599	1,685	3,917	2,894	4,307	1,844	2,343	4,487	1,995	1,580	898	2,941	5,191	4,035	3,011
18	2006 Regional Report Surplus Deficit	1,685	306	2,630	1,203	4,097	1,342	6,401	7,786	4,484	9,023	5,624	8,826	9,544	4,974	4,932
19	2007 Regional Report Surplus Deficit	2,183	749	2,572	1,644	4,397	1,656	4,554	3,355	8,699	9,752	3,426	4,788	5,944	4,637	4,189
20	2008 Regional Report Surplus Deficit	1,632	326	2,784	936	3,243	590	359	1,016	2,129	3,525	-775	6,358	11,031	8,087	3,242
21	2009 Regional Report Surplus Deficit	3,654	3,499	3,208	1,542	3,801	-714	3,212	1,488	722	6,195	3,896	4,798	6,248	4,160	3,088
22	2010 Regional Report Surplus Deficit	1,032	-87	2,497	1,533	3,047	-1,269	375	-348	248	3,026	-1,177	1,661	9,501	5,998	2,051
23	2011 Regional Report Surplus Deficit	2,341	1,406	3,359	1,386	3,027	2,460	8,317	9,988	7,428	11,260	5,052	6,832	13,250	14,608	6,692
24	2012 Regional Report Surplus Deficit	8,325	4,719	3,735	2,487	3,545	857	5,023	5,857	6,310	11,648	10,072	7,336	11,329	12,437	6,346
25	2013 Regional Report Surplus Deficit	6,165	5,103	3,382	1,665	5,973	4,472	2,122	2,359	2,127	9,847	4,542	5,728	9,118	5,562	4,609
26	2014 Regional Report Surplus Deficit	2,842	1,332	3,648	2,081	3,153	148	3,654	1,032	8,135	8,354	4,563	5,845	8,465	8,480	4,447
27	2015 Regional Report Surplus Deficit	3,193	1,462	3,289	1,624	5,725	3,555	5,998	8,433	9,366	6,180	534	679	2,827	749	3,957
28	2016 Regional Report Surplus Deficit	395	-165	2,649	1,097	2,907	701	1,088	1,796	7,794	9,490	8,261	5,009	5,082	1,953	3,248
29	2017 Regional Report Surplus Deficit	667	143	2,555	2,954	7,526	2,262	5,877	8,822	13,417	13,316	9,751	9,334	12,203	5,709	6,849
30	2018 Regional Report Surplus Deficit	4,676	2,425	2,889	1,574	2,745	1,234	6,867	9,751	6,755	8,087	6,210	10,367	9,120	4,356	5,492

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APPENDIX – REPORTS AVAILABLE UPON REQUEST

Please send request via email to WhtieBook@bpa.gov, and allow three to five business days for turn-around time.

A. Annual Energy (aMW) – Operating Years 2025 – 2034
B. Monthly Energy (aMW) – Operating Years 2025 – 2034

Report #	Report Descriptions
1	Federal Report Surplus/ Deficit
2	Regional Report Surplus/ Deficit
3	Regional Total Retail Load
4	Regional Exports
5	Regional Imports
6	Regional Intra-Regional Transfer
7	BPA Sales to Preference and Legacy Customers
8	Regional Regulated Hydro
9	Regional Independent Hydro
10	Regional Small Hydro
11	Regional Non-Hydro Renewable – Wind
12	Regional Non-Hydro Renewable – Solar
13	Regional Non-Hydro Renewable – Other
14	Regional Thermal – Nuclear
15	Regional Thermal – Coal
16	Regional Thermal – Natural Gas
17	Regional Thermal – Petroleum
18	Regional Thermal – Biofuel
19	Regional Thermal – Cogeneration
20	Non-Federal CER Deliveries to BPA
21	Federal Report Surplus/ Deficit by 30 Water Year
22	Regional Report Surplus/ Deficit by 30 Water Year

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5289 ▪ August 2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-142:
2025 Bonneville White Book

2025 Pacific Northwest Loads and Resources Study

May 2025

2025 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
May 2025

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

The McNary Dam is one of the four Federal projects located on the Lower Columbia River in the Pacific Northwest; it is part of the Columbia River Basin hydro projects. It serves a variety of purposes such as irrigation, navigation, recreation, and hydropower.

McNary Dam is a run-of-river type of Dam located roughly 290 miles upriver from the mouth of the Columbia River connecting Umatilla County, Oregon with Benton County, Washington. It has a powerhouse, navigation lock, as well as fish ladders and plays a major role in the transportation of commodities in the Columbia-Snake Inland Waterway. It is operated by the U.S. Army Corps of Engineers.

For more information on The McNary Dam, please visit: Walla Walla District - McNary Lock and Dam

https://www.nww.usace.army.mil/Locations/District-Locks-and-Dams/McNary-Lock-and-Dam/

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

May 16, 2025

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten-year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS) or to determine BPA revenues or rates.

This 2025 White Book presents the Federal system and the region's load obligations, contracts, and resources as of December 2024 for operating years (OY) 2026 through 2035. The 2025 White Book includes the following studies:

- Federal System Analysis—forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by water conditions. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm conditions; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 426 aMW to 1012 aMW. Overall, these annual energy deficit projections are more than those projected in the 2024 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses throughout the study period.
- PNW Regional Analysis—forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW region is projected to have an annual energy surplus as large as 960 aMW in OY2026, then sharply decreasing to a deficit of 3,026 aMW by OY2034. This result was mainly driven by the increasing PNW Retail Loads. Overall, the annual energy surplus/deficit position projections are more surplus than forecasts from the 2024 White Book until the outyears of the study period. Under median water conditions, the PNW region would begin to see energy deficits in the out years.

In February of 2025, BPA published our 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, and other Federal and State policy mandates. As with resources, there is also much uncertainty with loads including the potential for electrification and data centers coming online. The 2024 Resource Program publication and the 2025 White Book are available on BPA's website: https://www.bpa.gov/energy-and-services/power/resource-planning or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. The available report list can be found in the Appendix.

Please send questions and/or comments to whitebook@bpa.gov.

Sincerely,

MICHELLE CATHCART

Digitally signed by MICHELLE CATHCART
Date: 2025.05.27 13:17:25 -07'00'

Michelle Cathcart
Vice President| General Asset Management
Bonneville Power Administration
Enclosure

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SECTION 1: SUMMARY

Planning Context

The Pacific Northwest Loads and Resources Study, commonly referred to as the White Book, is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period from operating year (OY[1]) 2026 to 2035 (referred to in this document as "the study period"). The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest[2] (PNW) region. Information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. The load and resource balance are calculated by comparing expected loads and contract obligations to forecast resource generation and contract purchases under the Federal system. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW regional include variability by incorporating a variety of generation forecasts, associated with streamflow from the most recent 30-historical water conditions of the 2020 Modified Flows. These deterministic analyses are modeled by OY to be consistent with regional coordination of the Treaty. Analytical results are presented in annual and monthly energy, expressed in average megawatts (aMW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to comprehensively assess the ability of the power system to meet long-term load obligations. Periodically, Bonneville incorporates additional studies and data into its planning that look at different analytical methods and evaluate different scenarios. This year's White Book does not incorporate any additional studies.

The total retail load, contracts, and generation forecasts used in this study were updated as of December 31, 2024. The 2025 White Book supersedes the 2024 White Book and is published as a single summary document.

A list of technical reports can be located at the end of this summary document in the Appendix, individual reports are available upon request only. Request for these reports can be made by emailing WhiteBook@bpa.gov.

[1] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2026 is August 1, 2025 through July 31, 2026.

[2] As defined in the Northwest Power Act

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, forecasts are categorized as: 1) Total Retail Loads (TRL), defined as each individual utility's total retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region as Intra-Regional Transfers (Out) and outside the PNW region as Exports. Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperatives, and tribal utilities as preference customers described under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches, the largest share of load forecasts is now based on statistically adjusted end-use models while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions, using normalized temperatures based on recent history to incorporate evolving climate trends. Obligations associated with Bonneville's Preference Power Sales Contracts are forecasted to continue as currently elected through the study period, contract obligations not associated with Bonneville's Preference Power Sales Contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of physical generating facilities (currently on-line and/or under construction) and contract purchases that are used to serve retail loads. PNW resources, with Federal systems included, are predominantly hydro based; therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other renewable projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW regional as Intra-Regional Transfer (In) and from outside the PNW regional as Imports. Generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described in detail in the following sections.

Hydro Resources

- Regulated Hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydro-system Simulator (HYDSIM) model. The HYDSIM model considers

individual project operating characteristics and conditions to determine energy production expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30 historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.

- Independent Hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/ operators for the same 30-historical water conditions as the Regulated Hydro projects (1989 through 2018).
- Small Hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month; however, they are not assumed to be dependent on water conditions.

Non-Hydro Resources

- Wind – Firm wind generation incorporates the statistical modeling of wind generation based on historical weather data and actual generation from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as firm wind year. The firm wind year generation performance determines each project's energy forecast. The Federal system and PNW regional capacity analysis assume zero capacity contribution from wind resources.
- Solar – Solar projects are utility scale solar facilities that are metered and send generation to the grid; this does not include any behind the meter resources. Generation forecasts are either provided by individual project owners or are based on historical actual generation. The Federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other Renewable – Other renewable resources include all other projects identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal Resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel (not identified as renewable), and cogeneration projects. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced to account for scheduled maintenance. Forecasts are adjusted to show actual operational capabilities and expectations, and do not reflect economic dispatch.

Contract Purchases/ Imports

- Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publicly and in data submittals.

These purchases are treated as resources in both the Federal system and PNW regional analyses. Purchases between entities within the PNW are called Intra-regional Transfer (In) and purchases from entities outside the PNW are categorized as Imports. Except for contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms throughout the life of the contract and are not assumed to be renewed. Treaty power deliveries are assumed to be in place through the study period.

Adjustment to Resources

The White Book assumes that resource generation and contract purchases are reliably delivered to load centers. To take this assumption into account, this study adjusts generation forecasts for 1) Operating and Balancing Reserves, held to meet reliability standards; and 2) Transmission losses, associated with power deliveries. These adjustments are considered as reductions to both energy and capacity and are described below:

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing three percent of forecast load and three percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White book are modeled consistent with those used in Bonneville's BP-26 Rate Case process.
- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission Loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with Federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to Federal loads over non-Federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-26 Rate Case process:
    - Energy: 2.83 percent from September through May, and 3.04 percent from June through August.
    - Capacity: 2.88 percent from September through May, and 3.09 percent from June through August.
- Wheeling Loss (Financial Settlements): During the transmission of power from physical resource to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Wheeling losses are those losses incurred by transmission customers who have elected to settle those losses financially. The calculation of wheeling losses is based on the losses on the 'high-voltage network transmission' system.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month of the 30 year-historical streamflow record[3]: October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, first half -second half, due to natural streamflow and significant operational changes happening during these two months. Consequently, generations can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies encompass both power and non-power operating requirements. Each hydro study specifies non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The operations modeled include the following as outlined in the U.S. Army Corps of Engineers Pacific Northwest Coordination Agreement (PNCA) data submittals:

- National Marine Fisheries Services 2008 Willamette Biological Opinion (BiOp) (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 U.S. Fish and Wildlife Service Biological Opinion (November 12, 2019)
- 2023 MOU Appendix B 10-yr spill agreement (December 14, 2023)

Although the PNCA expired on September 15, 2024, PNCA project owners provided physical plant data as well as power and non-power constraints in a final data submittal to the Western Power Pool (WPP) in February 2024. Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. As with previous White Books, these assumptions were included through the 10-year study horizon. The 2025 White Book includes studies that reflect the expiration of the PNCA.

The construction of the three storage projects in Canada - Mica, Arrow, and Duncan - under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and allows a Detailed Operating Plan (DOP) to be

[3] 2020 Modified Flows

completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2025 AOP studies, with additional modifications that reflect updates used in the official 2025 DOP studies.

For the past several years, the United States and Canada have been in negotiations to modernize the Treaty. In July 2024, the United States and Canada reached a non-binding agreement on core issues to be reflected in a modernized Treaty and subsequently began the process of negotiating and drafting modernized Treaty text. During the pendency of these negotiations, the Countries agreed to implement a set of interim measures concerning the following aspects of Columbia River coordination:

- Beginning August 1, 2024, the Canadian Entitlement was reduced from 1141 Megawatts (MW) of hydropower generation capacity and 454 average MW (aMW) of energy to 660 MW of capacity and 305 aMW of energy. The Canadian Entitlement will stay at this reduced level until OY 2031, when it will be further decreased and then stabilized at 550 MW of capacity and 225 aMW of energy from OY 2034 through OY 2044.
- Effective November 1, 2024, Canada's Powerex assumed and started paying for 1,120 megawatts of transmission rights previously held by Bonneville to deliver the Canadian Entitlement.
- From September 2024 through 2027, Canada will provide 3.6 million acre-feet of water storage at Arrow Lakes reservoir for flood risk management for the United States, upon election and compensation by the Corps on behalf of the United States.
- Canada will provide up to 1.0 million acre-feet of flow augmentation to aid in salmon migration in the 2024-2025 operating year.

Bonneville along with the Corps is continuing to carry out and implement operational and other obligations pursuant to the current Treaty and associated agreements. The Canadian Entitlement energy amounts included in this White Book for OY 2026 through OY 2035 are based on the amounts identified above.

Balancing reserves, both incremental and decremental, reduce the ability to shape the Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects.

Firm planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet obligation loads. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the Federal System this is established by considering the historical streamflow record, power and non-power operation constraints and the planned operation of non-hydro resources, combined with the

system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program[4].

Variability of Hydro Generation

The generating capacity of the Federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities, 2) the physical capacity of the facilities, 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or applicable agreements, and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year-to-year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, Federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

- Firm water: tenth percentile (P10) of system generation by month, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month, it represents the exact middle value of generation distribution for energy and capacity of the hydro system.
- High water: 90th percentile (P90) of system generation by month, this represents the high generation scenario of the energy and capacity of the hydro system.

Hydro Capacity Modeling

Bonneville uses the RiverWare[5] model to forecast usable hydro capacity for long-term planning purposes. RiverWare incorporates the monthly historical 30 water year reservoir storage and flows from HYDSIM to simulate the relationship of hydro energy to hydro peaking capability for Federal system regulated hydro resources. For each month, RiverWare forecasts hourly Federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts consider scheduled hydro maintenance and reserves.

[4] Bonneville Power Administration Resource Planning

[5] RiverWare is a river system modeling tool developed by the University of Colorado Boulder College of Engineering and Applied Science, more specifically by the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES). RiverWare | Center for Advanced Decision Support for Water and Environmental Systems | University of Colorado Boulder

Notable Updates

- The 2025 White Book includes updated forecasts of Federal system power sales contracts (PSC) obligations, PNW regional Total Retail Loads (TRL), contract purchases, and generation as of December 1, 2024.

Hydro capabilities in this study also reflect the updated Resilient Columbia Basin Agreement (RCBA, also known as the 12/14 agreement), published on 12/15/2023. Key items include:

- Spilling most projects in the spring to 125% Total Dissolved Gas (TDG) gas cap in the spring 24/7.
- John Day spills 40% of outflow for 16 hours during the day, and 125% TDG for 8 hours at night.
- Little Goose spill includes 8 hours of spill totaling 30% of outflow allowing for adult passage and 125% TDG for the remaining 16 hours, except 30% of outflow spill early in season does not begin until the sooner Apr 24th or adult criteria are met.
- Late summer spill transitions on August 1st instead of August 15th.
- Steelhead spill Sept-Nov 15th is everyday instead of every other day (4 hours per day via 1 Spillway Weir).
- Steelhead and early run juvenile spills are 24/7 beginning March 21st until the start of juvenile spill.

Sources of Uncertainty

Forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and a variety of other factors that could significantly affect the magnitude, duration, and timing of projected surpluses and/or deficits. Uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations,
- Changes to hydro system operations in response to court actions and/or operational agreements,
- Natural variations in weather affecting electrical power demand and streamflow runoff that result in hydroelectric power generation changes,
- Potential new large individual retail load and/or other changes to major industrial operations,
- Potential service to new load such as new customers or the Department of Energy's Richland vitrification plant operations,
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions,
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets,
- Changes to operating limits on existing and future thermal resources,

- Changes to retirement dates associated with resources,
- Failures of resources to operate at anticipated times and/or output levels,
- Changes to Treaty operations after the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future obligations related to Provider of Choice elections.

The potential impacts of these and other sources of uncertainty are not quantified in this study.

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SECTION 2: FEDERAL SYSTEM ANALYSIS

The Federal System Analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY2026 through 2035. This analysis incorporates forecasts of the Federal system's firm requirement PSC obligations, contract sales and purchases, and resource generations. This section presents firm Federal system load and resource forecasts for energy. Additional detailed components of the Federal system study are available only upon request, a list of available reports can be found in the Appendix.

Load Obligations

Bonneville's ALF system is used to forecast Federal system load obligations, as described previously in Section 1: Summary – Load Obligations. Types of Federal system load obligations include: 1) Federal reserve power obligations to the U.S. Bureau of Reclamation (USBR), 2) Bonneville's Regional Dialogue (RD) PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers, 3) contract obligations to investor-owned utilities (IOUs), 4) contract obligations to Direct Service Industry (DSI) customers, and finally 5) other Bonneville contract obligations including contract sales to entities within the PNW region (Intra-Regional Transfers (OUT)) and to those outside the PNW region (Exports). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather conditions, water supply, or economic environments. Bonneville's forecasts of these obligations are categorized in the following sections.

USBR obligations

USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. The remaining power from USBR projects are marketed by Bonneville in the PNW.

RD Contract High Water Mark (CHWM) PSC obligations to Public & Federal agency customers

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 124 are Load Following customers, 7 are Slice/Block, and three are Block.

Under the RD PSCs, customers made periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[6] load by 1) adding new non-Federal resources; 2) acquiring power from non-

[6] "Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either

Federal resources; and/or 3) requesting Bonneville to supply additional power (as a Tier 2 load service). The final customer election was made in October 2024 and set through fiscal year (FY) 2028, and this study assumes these along with the current contract elections continue throughout the study period. Based on this assumption, Federal system RD PSC obligation forecasts include elected and forecasted A-RHWM (Tier 2) load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP26 Rate Case)

FY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy aMW	534	579	619	696	692	734	768	806	836	862

IOU Load Service under Regional Dialogue (RD) PSCs

There are six IOUs in the PNW region, and they are: Avista Corporation, Idaho Power Company, Northwestern Energy Division of Northwestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Although these IOUs all signed Bonneville RD PSCs for FY 2011 through FY 2028, no IOUs have elected to take power service under these contracts thus no net requirement power sales are assumed for the IOUs through this study period.

Direct Service Industrial (DSI) Contracts

Bonneville currently has one DSI customer, Port Townsend Paper Corporation. DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations

Bonneville provides Federal power under a variety of additional contract arrangements. These contracts obligations are categorized as: 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payment for services; and 5) power commitments under the Treaty. These arrangements, collectively referred to as "Other Contract Obligations", are determined by individual contract provisions and have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region as Intra-Regional Transfers (Out), and to those outside of the PNW region as Exports.

Treaty, RD PSCs, and DSI power deliveries are assumed to remain in place throughout the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after the expiration date.

Conservation

The PSC obligation forecasts developed by the ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load

non-Federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-Federal resources. (P.4 Regional Dialogue July 2007)

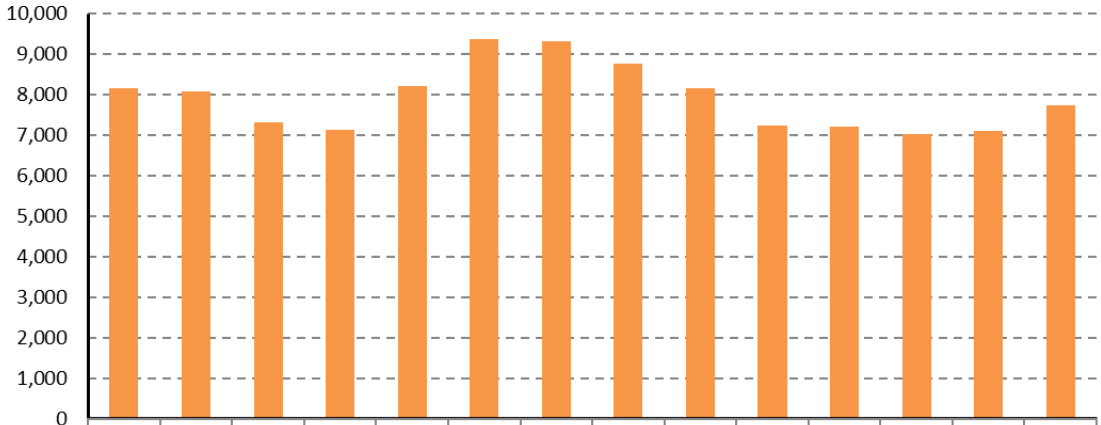
forecasts, it is expected that the historically embedded amount of conservation acquired will continue at the same rate going forward across the study period.

Firm Loads

The Federal system total firm load forecast shows a 4.3 percent average annual load growth over this study period. While Bonneville's forecast of PSC requirement loads increased roughly 9 percent over the study period, Bonneville's Exports and Intra-Regional Transfers (OUT) decreased due to the expiration or decrease in delivery of contracts.

Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While on an annual basis these obligations demonstrate little variation across the study period, Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[7] experiences its highest loads in the late fall and winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer and early fall months when temperatures are mild. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecasted Federal system firm load obligations for OY2026.

Table 2-2 Federal System Firm Obligations for OY2026 - Monthly



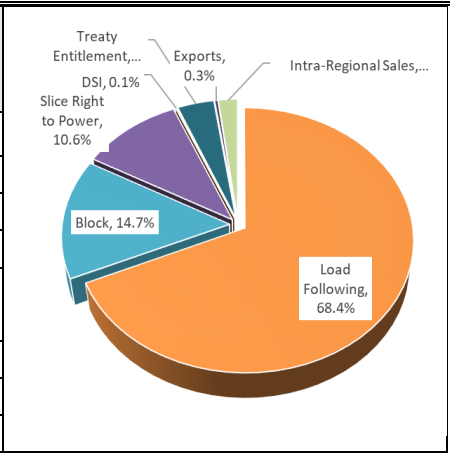
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	8169	8087	7315	7126	8218	9374	9325	8762	8168	7242	7202	7038	7104	7730

Table 2-3 shows the annual make-up of the Federal system firm load obligations for OY2026 in Energy aMW.

[7] This is reflective of Bonneville's total aggregate loads, individual customers highest loads vary by month and season.

Table 2-3 Federal System Annual Firm Obligations by Category OY2026

Customer Class	RD PSCs	Energy (aMW)	Percent of Firm Energy
Load Following	Yes	5,443	68.4%
Block	Yes	1,171	14.7%
Slice Right to Power	Yes	843	10.6%
DSI	No	11	0.1%
Treaty Canadian Entitlement	No	305	3.8%
Exports	No	26	0.3%
Intra-Regional Sales	No	160	2.0%
Total Firm Obligations	**na**	**7,958**	**100%**



As previously noted, RD PSCs expire at the end of FY2028, and negotiations for new 19-year Provider of Choice PSCs are ongoing with contracts expected to be executed in December 2025. Given the uncertainty around post-2028 obligation levels, this study assumes a continuation of RD PSC load levels for planning purposes.

Resources

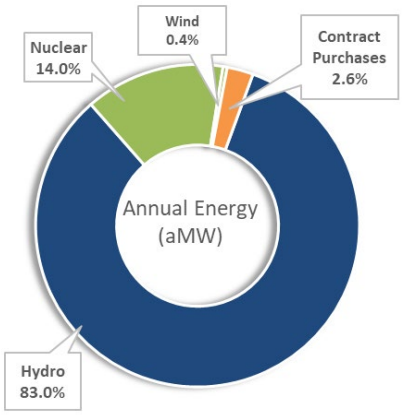
In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By statute, Bonneville does not own generating resources, but instead, Bonneville markets power from Federal resources and non-Federal generating resources whose output Bonneville has acquired under contract. These resources and contract purchases are collectively referred to as "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources (wind projects); 3) Thermal resources, (Columbia Generating Station); and 4) Contract purchases, which are purchases from entities within the PNW region as Intra-Regional Transfers (In), including the estimated Mid-C Non-Federal Canadian Entitlement Return power (downstream benefit return as part of Columbia River Treaty) and from those outside of the PNW region as Imports.

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY2026, Federal system resources are forecast to produce 7,532 annual aMW of generation under Firm water conditions, with reserves and losses included.

Table 2-5 Federal System Generations by Resource Type for OY2026 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,629	83%
Nuclear	1,116	14%
Wind	33	0.4%
Contract Purchases	209	2.6%
Total Federal Resources	7,988	100%
Reserves & losses	-455	--
Total Net Resources	7,532	--



Federal system contract purchases

Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region as Intra-Regional Transfers (In), and from outside the region as Imports, to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases; 2) power or energy exchange purchases; 3) the estimated Mid-C Non-Federal Canadian Entitlement Return power; and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contract, and these returns are treated as Federal system resources. Except for the estimated Mid-C Non-Federal Canadian Entitlement Return power and transmission loss return of Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed.

The Federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 details the Federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally, it shows the variability of individual Federal system hydro project generation for the three water conditions: firm, median, and high.
- Federal system non-hydro resources: Federal system non-hydro resources are generating resources whose output has been purchased by Bonneville. Table 2-7 details these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year but may change annually based on scheduling of annual maintenance, refueling, and capital improvements.

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[8] – OY2026

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity [d/] (MW)	High [c/] Energy (aMW)	Median [c/] Energy (aMW)	Firm [a/c/] Energy (aMW)
Regulated Hydro							
1. Albeni Falls	1955	USACE	3	50	22.5	24.3	24.2
2. Dworshak	1974	USACE	3	465	274	184	171
3. Hungry Horse	1952	USBR	4	310	105	102	95
4. Libby	1975	USACE	5	605	262	242	195
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,045	2,432	1,906
	1973		6	314			
6. Chief Joseph	1955	USACE	27	2,614	1,751	1,433	1,133
7. Lower Granite*	1975	USACE	6	930	259	159	134
8. Little Goose*	1970	USACE	6	930	315	178	154
9. Lower Monumental*	1969	USACE	6	930	290	172	145
10. Ice Harbor*	1961	USACE	6	693	254	167	143
11. McNary**	1953	USACE	14	1,120	676	543	447
12. John Day**	1968	USACE	16	2,480	1,221	910	771
13. The Dalles**	1957	USACE	22	2,080	955	801	639
14. Bonneville [b/]**	1938	USACE	18	1,221	711	512	395
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,142**	**7,859**	**6,354**
Independent Hydro Projects							
16. Anderson Ranch	1950	USBR	2	40	15	13	9
17. Big Cliff***	1954	USACE	1	21	14	12	11
18. Black Canyon	1925	USBR	2	8.5	8	6	6
19. Boise Diversion	1908	USBR	3	2.5	2	1	1
20. Chandler	1956	USBR	2	12.2	8	7	6
21. Cougar***	1964	USACE	2	28	8	7	5
22. Cowlitz Falls	1994	LCPD#1	2	70	34	27	24
23. Detroit***	1953	USACE	2	115	33	26	24
24. Dexter***	1955	USACE	1	17	10	8	8
25. Foster***	1968	USACE	2	23	10	8	8
26. Green Peter***	1967	USACE	2	92	24	15	13
27. Green Springs	1960	USBR	1	18	7	7	7
28. Hills Creek***	1962	USACE	2	34	24	17	15
29. Lookout Point***	1954	USACE	3	138	11	18	15
30. Lost Creek	1975	USACE	2	56	38	37	30
31. Minidoka	1909	USBR	4	28	18	15	11
32. Palisades	1957	USBR	4	177	93	90	74
33. Roza	1958	USBR	1	14	9	8	7
34. Total Independent Hydro Projects			**38**	**894**	**365**	**323**	**273**
Small Non-Federally Owned Hydro Projects							
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**
38. Total Hydro Generation ***(line 15 + line 34 + line 37)***			**209**	**22,327**	**10,510**	**8,185**	**6,629**

* Lower Columbia Projects ** Lower Snake River Projects *** Willamette River Projects

a/ Firm energy is the 12-month annual average for OY 2025 assuming 10th percentile (P10) water conditions

b/ Bonneville Dam generation totals include Bonneville Fishway

c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile

d/ Maximum Capacity represent full capacity of resource including overload.

[8] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY2026

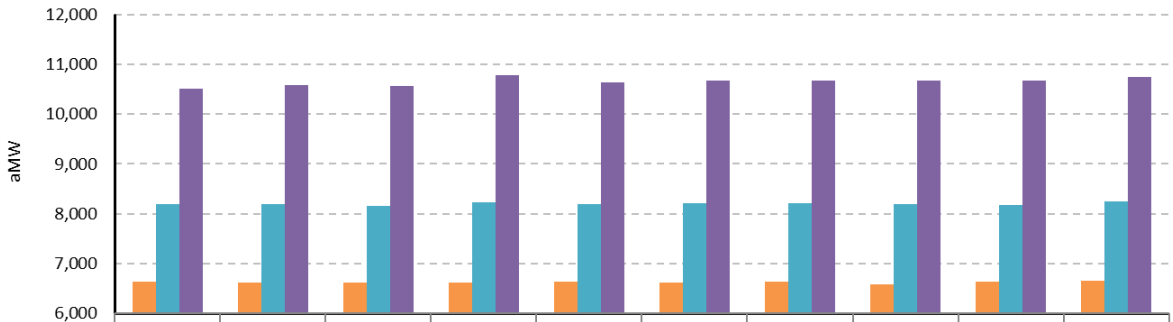
	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	1,116
2	Stateline Wind Project [b/]	2001	Wind	PPM, FLP	0	21.2
3	Klondike Phase III [c/]	2007	Wind	NW Wind Power	0	11.8
4	Fourmile Hill Geothermal [d/]	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,149**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				147	84
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	107
10	Slice Transmission Loss Return				29	17
11	**Total Federal System Contract Purchases**				**352**	**209**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,530**	**1,358**

a/ This is the maximum generation for January 2025
b/ Stateline Wind Project contract expiring in 2028
c/ Klondike Phase III Project expiring in 2029
d/ Fourmile Hill is not assumed to be in operation within the study period

Federal System Hydro Generation Variability

The generating capacity of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, a combination of other power and non-power constraints, and other operating limitations. Table 2-8 shows the annual variability of hydro generation under the three water conditions. Although hydro generation changes drastically from different water conditions, within each condition; however, it changes only slightly from year to year.

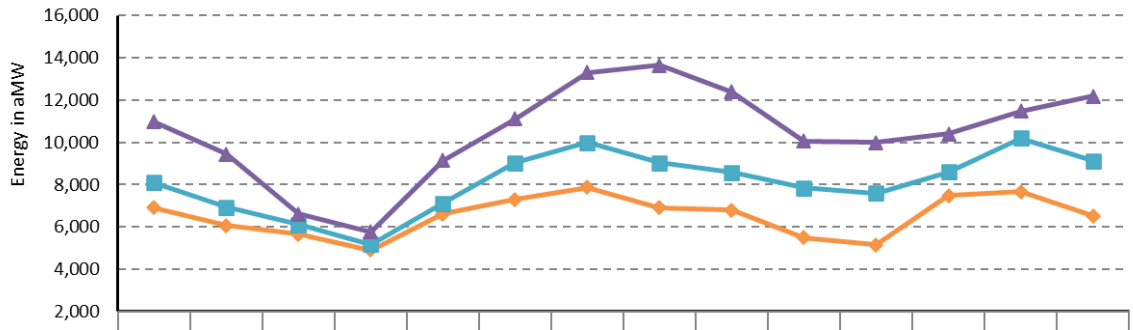
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY2026 – OY2035



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm Water (P10)	6,629	6,616	6,623	6,625	6,634	6,622	6,645	6,589	6,635	6,651
Median Water (P50)	8,185	8,188	8,152	8,231	8,195	8,206	8,210	8,194	8,184	8,253
High Water (P90)	10,510	10,581	10,572	10,775	10,640	10,675	10,666	10,679	10,669	10,739

In OY2026, annual Federal system hydro energy generation is forecasted to be 6,629 aMW under Firm Water conditions. However, under the High Water conditions these same Federal system hydro resources could generate as much as 10,510 aMW. Table 2-9 displays the monthly variability of the Federal system hydro generation forecasted for OY2026, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood control and power production. Available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has little impact on generation from the Federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by over 6,500 aMW in a single month, almost doubled in this case February, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2026

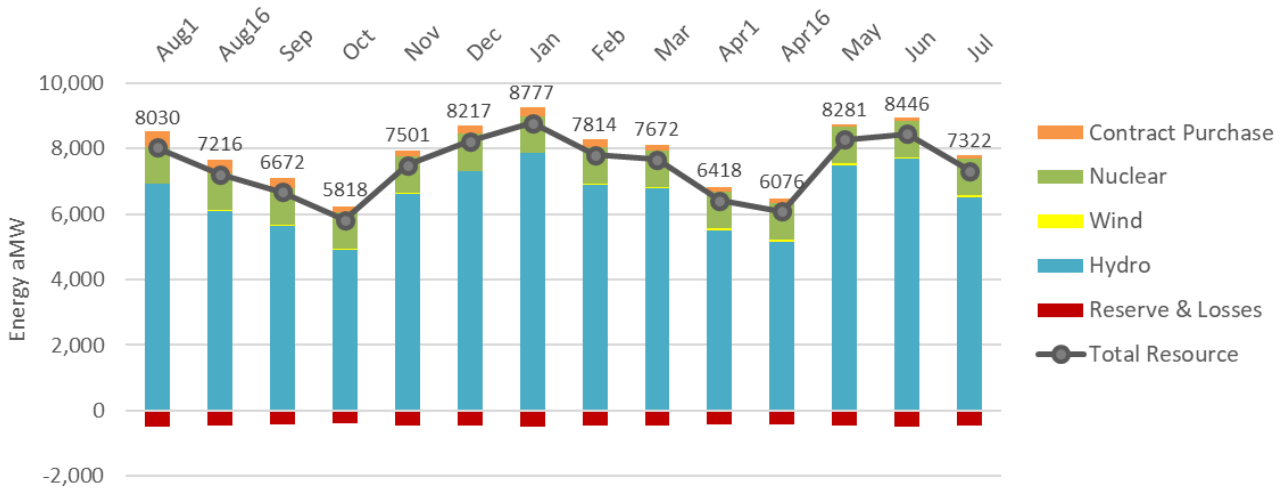


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,921	6,078	5,649	4,912	6,611	7,300	7,861	6,903	6,792	5,504	5,162	7,492	7,678	6,520
Median Water (P50)	8,108	6,945	6,121	5,189	7,129	9,043	10,000	9,045	8,573	7,851	7,607	8,599	10,206	9,118
High Water (P90)	10,972	9,448	6,620	5,779	9,153	11,113	13,307	13,648	12,387	10,056	9,998	10,393	11,487	12,178

Total Federal System Resources

Table 2-10 shows the monthly shape of forecasted total Federal system generation for energy (in aMW) for OY2026, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources, as well as contract purchases. Overall, the Federal system has the highest net generation forecasted in winter months to early spring and mid-summer periods.

Table 2-10 Federal System Monthly Generation for OY2026 under Firm Water Conditions



Key Results

Annual Energy

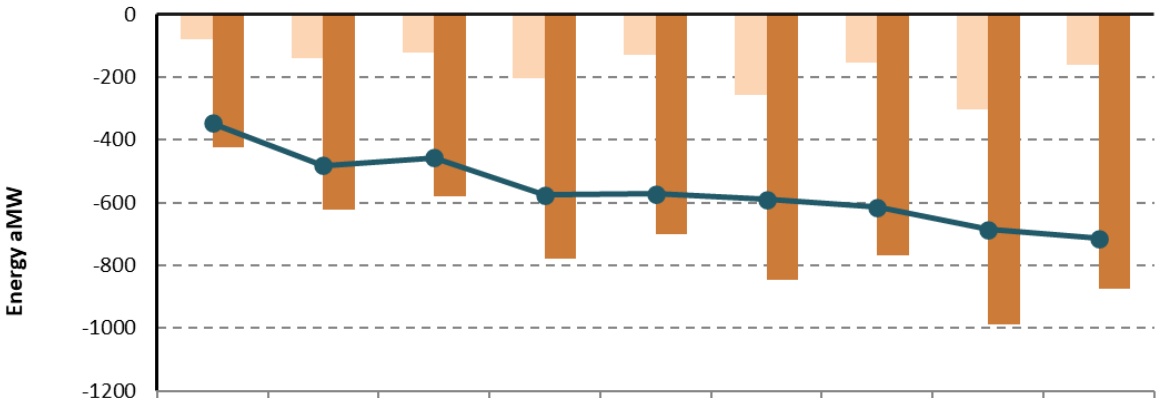
Table 2-11 shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY2026 through OY2035. The Federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY2026.

Table 2-11 Federal System Annual Energy Surplus/Deficit under Firm Water Conditions

Energy (aMW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Surplus/ Deficits	-426	-622	-580	-778	-701	-846	-768	-988	-876	-1012

Table 2-12 compares the 2025 White Book Federal system annual firm energy surplus/deficit results to those from the 2024 White Book. In this comparison, the 2025 White Book shows a consistent increase in deficits annually throughout the studying period. These results reflect changes in both Federal load obligations and Federal system generations.

Table 2-12 Federal System Annual Energy Surplus/Deficits Comparison under Firm Water

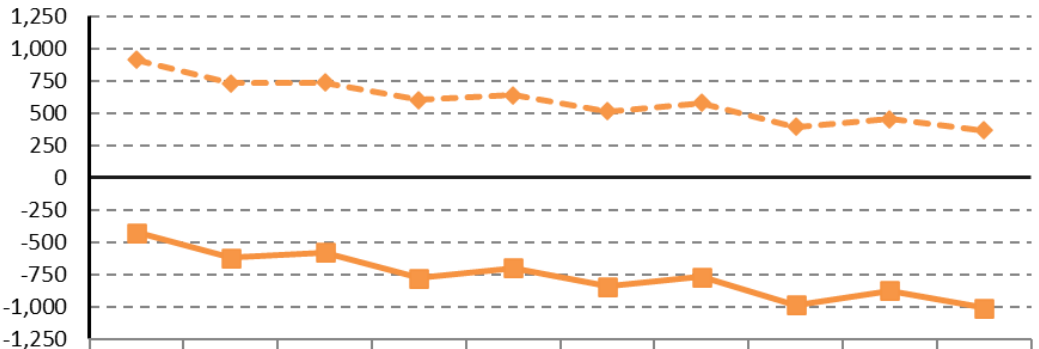


	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 White Book	-79	-139	-122	-203	-128	-257	-153	-303	-161
2025 White Book	-426	-622	-580	-778	-701	-846	-768	-988	-876
Delta	-346	-482	-457	-575	-572	-589	-615	-685	-715

Federal System Annual Surplus/ Deficit

Table 2-13 graphically presents the annual firm and median conditions energy surplus/deficits. Over the study period, the Federal system is forecasted to have a deficit in annual firm energy as high as 1,012 aMW in the last year of the study period. Noticeable differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) maintenance schedule[9]. Under Median Water conditions, the Federal System is surplus throughout the study period.

Table 2-13 Federal System Annual Surplus/ Deficits Under Firm Water Conditions



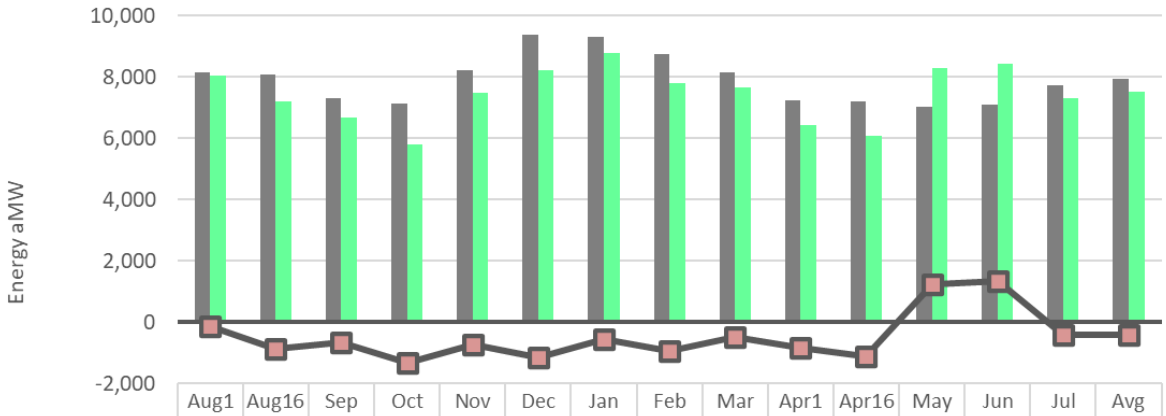
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy (aMW)	-426	-622	-580	-778	-701	-846	-768	-988	-876	-1,012
Energy (aMW) p50	911	729	734	601	639	514	576	390	454	364

[9] CGS has routine maintenance cycle scheduled in odd calendar years, specifically in months of May and June. CGS is forecast to produce 994 aMW annually during maintenance years, and 1,116 aMW annually during non-maintenance years.

Federal System Monthly Surplus/ Deficit

Table 2-14 displays a graphic look at the Federal system monthly firm energy surplus/deficits for OY2026. Largest deficit comes in the month of October and better positions in the months of May and June, after spring run-off.

Table 2-14 Federal System Monthly Surplus/ Deficits OY2026 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Total Firm Obligations	8169	8087	7315	7126	8218	9374	9325	8762	8168	7242	7202	7038	7104	7730	7958
Total Net Resources	8030	7216	6672	5818	7501	8217	8777	7814	7672	6418	6076	8281	8446	7322	7532
Surplus/ Defiict	-139	-871	-643	-1308	-716	-1157	-549	-948	-497	-825	-1127	1243	1342	-408	-426

Conclusion

Under Firm water conditions, the Federal system shows annual firm energy deficits through the 2026-2035 study period. These annual energy deficits range from 426 aMW in OY2026 to as high as over 1,000 aMW in OY2035. At a monthly resolution under Firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The Federal system surplus/deficit forecasts generally have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by over 5,500 aMW within the same year.

The range of Federal system monthly surplus and deficit forecasts under all 30-water years is presented in Exhibit 4-3. Additional monthly and annual details for OY2026 through OY2035 are available upon request, a list of available data reports can be found in the Appendix. Reminder: Data Report requests can be sent to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2026 through OY 2035. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resources forecasts incorporate annual regional utility data submittals received by Bonneville.

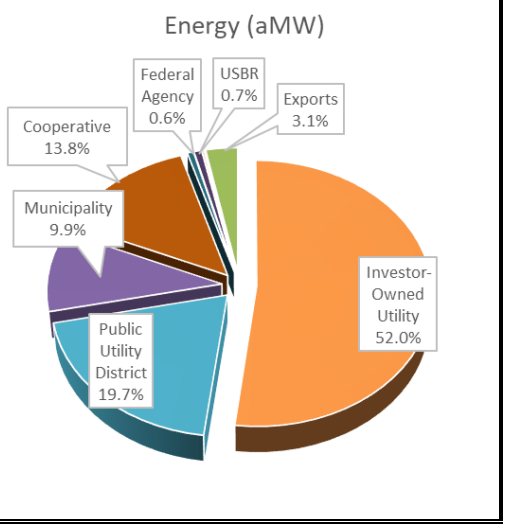
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historical conservation savings, and do not include specific adjustments for evolving climate trends. Apart from power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration dates. Treaty power deliveries are assumed to be in place throughout the study period. The sum of the forecasted TRL and Export contracts represents the regional loads for the PNW.

Regional loads are comprised of roughly 96 percent retail loads and four percent exports. Table 3-1 shows the forecasted composition of PNW regional load for OY2026.

Table 3-1 PNW Region Firm Loads by Customer Category – OY2026

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,617	52%
Public Utility District	5,518	19%
Municipality	2,582	10.2%
Cooperative	3,624	14.3%
Federal Agency	157	1%
USBR	192	0.8%
DSI	51	0.2%
Marketer	0	0.0%
Total Retail Load	**25,380**	**97%**
Exports	814	3.9%
Total Regional Load	**26,194**	**100%**



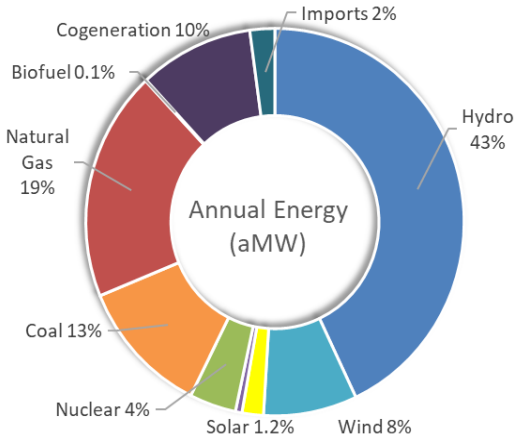
Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Similarly to the Federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources which include wind, solar, and other projects; 3) Thermal resources which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases which are identified as Imports.

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY2026 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,013	43%
Wind	2,240	8%
Solar	510	1.8%
Other Renewable	157	0.6%
Nuclear	1,116	4%
Coal	3,201	11%
Natural Gas	5,371	19%
Petroleum	0	0%
Biofuel	26	0.1%
Cogeneration	2,730	10%
Imports	597	2%
Total Regional Resources	**27,960**	**100%**



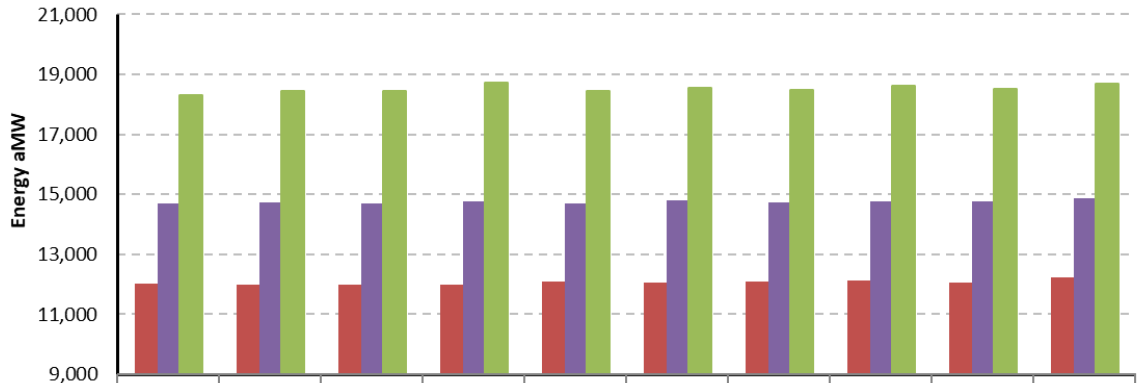
Regional Hydro Generation Variability

The generating capacity of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to Federal Hydro Resources, Bonneville utilizes the 30-year streamflow record for planning purposes. Similarly, three water conditions are presented here to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three streamflow scenarios. Details on the different streamflow scenarios please refer to Hydro Resource Modeling section.

In OY2026, annual firm energy generation from regional hydro projects is forecasted to be 12,013 aMW under the firm water conditions, and this represents about 43% of the region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW between firm and high water conditions.

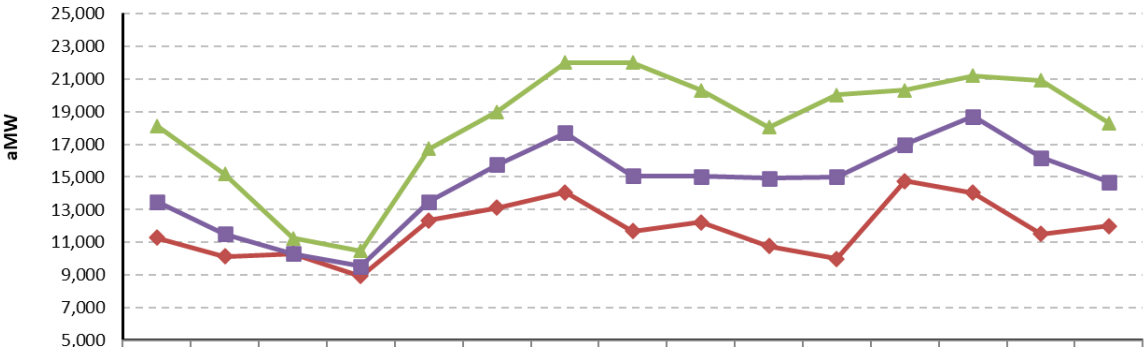
Table 3-4 PNW Regional Annual Variability of Hydro Generation by Streamflow Conditions



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm Water (P10)	12,013	11,971	12,005	11,991	12,085	12,056	12,094	12,130	12,048	12,235
Median Water (P50)	14,687	14,741	14,684	14,756	14,709	14,813	14,724	14,766	14,749	14,874
High Water (P90)	18,303	18,444	18,452	18,732	18,447	18,554	18,476	18,620	18,512	18,675

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2026. The increased level of generation in January through March is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early full as streamflow are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through October as those are the months with overall lowest water availabilities. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions within the same month.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions - OY2026



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	11,278	10,148	10,313	8,946	12,350	13,126	14,067	11,686	12,234	10,785	9,998	14,753	14,029	11,502	12,013
Median Water (P50)	13,487	11,523	10,305	9,538	13,496	15,761	17,699	15,064	15,053	14,935	15,002	16,984	18,711	16,195	14,687
High Water (P90)	18,127	15,191	11,250	10,479	16,727	18,990	21,999	22,004	20,300	18,056	20,015	20,309	21,207	20,922	18,303

Uncommitted IPP Generation Delivered to the PNW Region

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources that are not committed to serving specific loads, represent approximately 2,550 aMW of energy for OY2026. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY2026 through OY2035 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy (aMW)	2,550	2,474	2,503	2,513	2,510	2,512	2,508	2,508	2,508	2,519

Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect those changes.

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY2026 Firm Water Conditions

Project	Fuel Type	Energy (aMW)
Airport Solar	Solar	13
Centralia Complex [a/b/]	Coal	91
Clearwater Wind	Wind	23
Condon Wind	Wind	12
Cosmopolis Specialty Fibres	Wood Waste	14
Goose Prairie Solar	Solar	17
Hermiston Power Project	Wood Waste	567

Project	Fuel Type	Energy (aMW)
International Paper Energy Center	Wood Waste	16
Juniper Canyon Wind	Wind	36
Kittitas Valley Wind	Wind	24
Klamath Generation Facility	Natural Gas	436
Klamath Generation Peakings (CT)	Natural Gas	90
Klondike Wind 1	Wind	6
Klondike Wind 3	Wind	23
Klondike Wind 3a	Wind	18
Leaning Juniper Wind	Wind	47
Longview Fibre Paper & Packaging	Wood Waste	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	5
Pelton	Hydro	14
Priest Rapids	Hydro	85
Rock Island	Hydro	84
Rocky Reach	Hydro	156
Round Butte	Hydro	31
Satsop Combustion Turbine Project	Natural Gas	584
SDS Lumber	Wood Waste	1
Smith Creek (Idaho)	Hydro	7
Stateline Wind	Wind	8
Stimson Lumber (Plummer)	Wood Waste	7
Tacoma Biomass (WestRock)	Wood Waste	0
Tieton Dam (Yakima)	Hydro	0
Vansycle Wind	Wind	23
Wanapum	Hydro	25
Weyerhaeuser Longview	Wood Waste	35
Willow Creek Wind	Wind	17
Total Uncommitted IPP Generation		**2,550**

[a/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025. Puget purchased an increasing amount of this project beginning Dec 1, 2014 and ending Nov 30, 2025.

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,550 aMW in OY2026 is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY2026 through OY2034 are shown in Exhibit 5-1, and OY2026 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY2026 through OY2035 are available upon request via email at WhiteBook@bpa.gov.

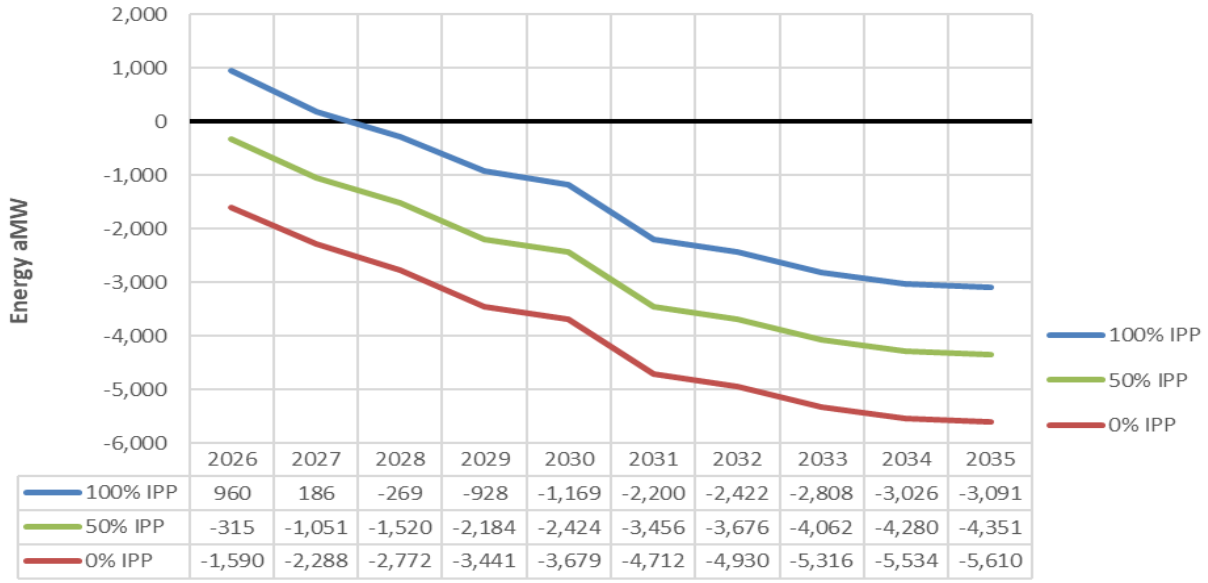
Table 3-8 PNW Regional Annual Energy Surplus/ Deficit - Firm Water Conditions

Assuming 100% of Uncommitted IPP Generation is Available to the Region

Energy (aMW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Surplus/ Deficit	960	186	-269	-928	-1,169	-2,220	-2,422	-2,808	-3,026	-3,091

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

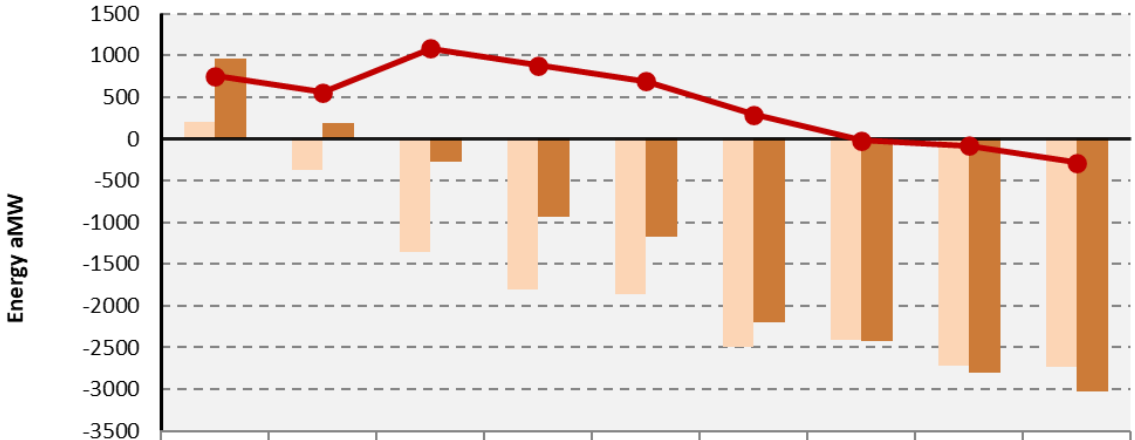
Table 3-9 PNW Regional Annual Energy Surplus/ Deficit by Uncommitted IPP Generation %



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
100% IPP	960	186	-269	-928	-1,169	-2,200	-2,422	-2,808	-3,026	-3,091
50% IPP	-315	-1,051	-1,520	-2,184	-2,424	-3,456	-3,676	-4,062	-4,280	-4,351
0% IPP	-1,590	-2,288	-2,772	-3,441	-3,679	-4,712	-4,930	-5,316	-5,534	-5,610

Table 3-10 compares the 2025 White Book PNW regional annual firm energy surplus/ deficit forecasts to that of the 2024 White Book. The comparison shows significant change, the 2025 White Book shows OY2026 to have over 700 aMW more surplus energy available, and this continues through OY2028 where 2025 White Book forecast showed over than 1,000 aMW of change resulting in less deficit than forecasts from 2024 White Book. This change is mainly driven by the decrease in the PNW Regional Retail Load, more specifically in the new large industrial loads category. By OY2032 the forecasted regional position is very similar to the 2024 White Book, with growing deficits after that point in the study.

Table 3-10 PNW Regional Annual Surplus/ Deficit Comparison – Firm Water Conditions Assuming 100% Uncommitted IPP Generations available to the Region

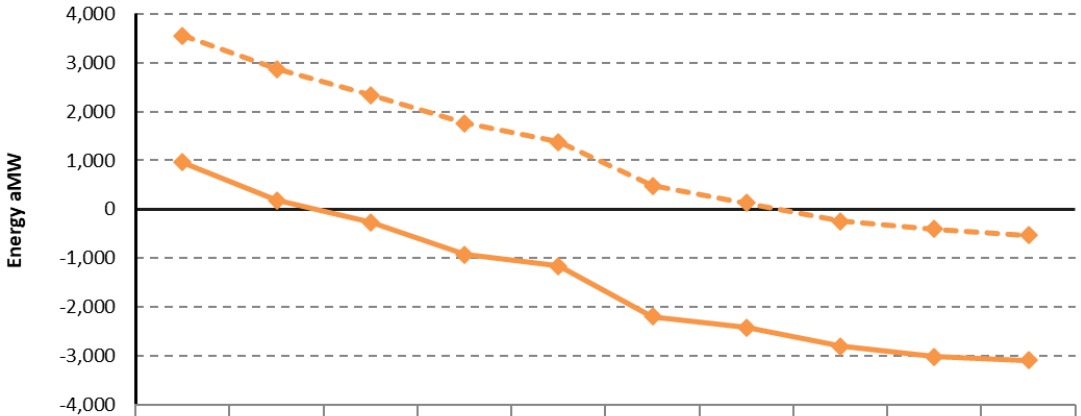


	2026	2027	2028	2029	2030	2031	2032	2033	2034
2024 White Book	207	-370	-1352	-1808	-1861	-2492	-2407	-2725	-2738
2025 White Book	960	186	-269	-928	-1169	-2200	-2422	-2808	-3026
Delta	753	556	1084	880	692	293	-15	-84	-288

Regional Annual Surplus/ Deficit

Table 3-14 graphically presents the annual firm energy surplus/ deficit forecasts for the PNW region under firm (P10) and median (P50) conditions. These forecasts assume 100 percent availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/ deficit declines over the 10-year study period.

Table 3-14 PNW Regional Annual Surplus/ Deficit – Firm & Median Water Conditions

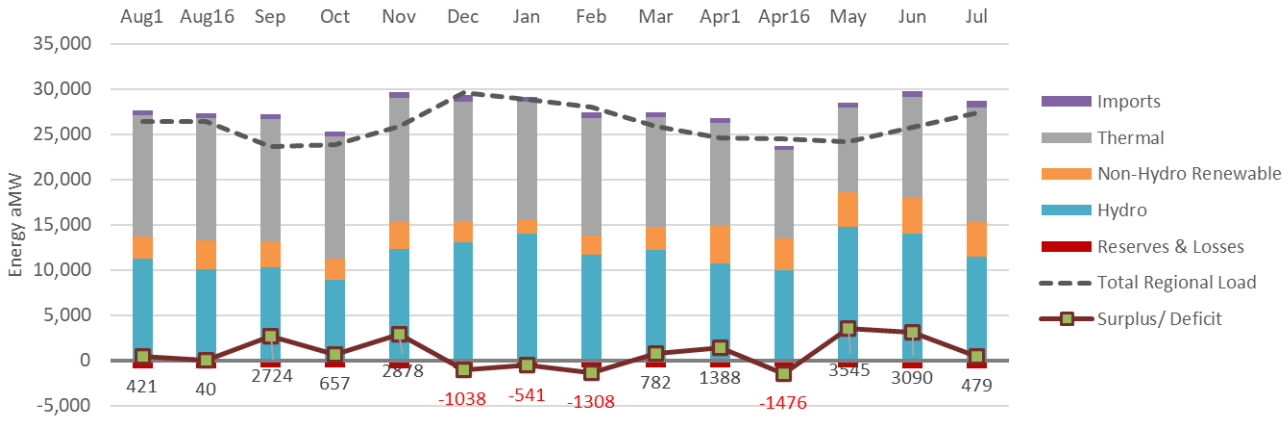


	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy P10	960	186	-269	-928	-1,169	-2,200	-2,422	-2,808	-3,026	-3,091
Energy P50	3557	2876	2333	1758	1378	477	132	-248	-403	-529

Regional Monthly Surplus/ Deficit

Table 3-15 shows the monthly energy surplus/ deficit forecast for OY2026, accompanied with monthly total firm obligations and resources by category. Again, these forecasts assume 100 percent of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to the beginning of summer when hydro generation is high, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin.

Table 3-15 PNW Regional Monthly Surplus/ Deficit – OY2026 Firm Water Conditions



Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years, with surpluses declining and quickly becoming deficits and growing into larger deficits going into the outyears, under the assumption of 100 percent of the PNW region's uncommitted IPP generation available to serve the region's load. Additionally, because of the full uncommitted IPP generation assumption to serve the region's load, with its uncommitted nature, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly. Under the median (P50) water conditions, the PNW region sees surpluses until the outyears of OY 2032.

Notably, the region's retail load forecasts adjusted downwards significantly in the front half of the study period from 2024 Whtie Book forecast, this is driven by the uncertainty of the new large single load category of the retail loads.

Detailed surplus/deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-3; monthly and annual details for OY2026 through OY2035 are available upon request with the itemized list located in the Appendix.

The regional energy deficits identified in this study may be mitigated through resource options discussed in the NWPCC's Power Plan publications, NWPCC is currently working on updating their

2021 Northwest Power Plan[10] and it is updated roughly every 5 years. Bonneville provides this PNW regional planning analysis for informational purposes only.

[10] The 2021 Northwest Power Plan (nwcouncil.org)

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SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/ Deficit:

Operating Years 2026 – 2035, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2026 to 2035 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/16/2025**
S268-WB-20250415-174748

	Energy-aMW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Firm Obligations										
1	**Load Following**	5443	5525	5581	5665	5718	5767	5810	5859	5895	5930
2	Preference Customers	5096	5175	5225	5300	5349	5396	5437	5483	5517	5550
3	Federal Agencies	155	158	161	168	172	174	176	179	181	183
4	USBR	192	192	194	197	197	197	197	197	197	197
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	560	573	586	583	588	590	590	590	589	589
7	Tier 1 Block	560	573	586	583	588	590	590	590	589	589
8	**Slice**	1454	1439	1441	1430	1440	1435	1439	1431	1438	1435
9	Slice Block	611	613	601	604	595	600	588	601	588	598
10	Slice Output from T1 System	843	826	839	826	845	835	851	830	850	838
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	491	340	328	328	301	246	247	246	247	247
14	Exports	331	317	318	317	290	237	237	237	238	237
15	Intra-Regional Transfers (Out)	160	22.4	10.7	10.7	10.7	9.44	9.44	9.44	9.44	9.44
16	**NR Obligation**	0	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0
17	NR Rate Load	0	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0
18	**Total Firm Obligations**	**7958**	**7905**	**7971**	**8048**	**8092**	**8096**	**8156**	**8202**	**8254**	**8286**
	Net Resources										
19	**Hydro**	6629	6616	6623	6625	6634	6622	6645	6589	6635	6651
20	Regulated Hydro - Net	6354	6344	6353	6353	6355	6340	6367	6326	6379	6391
21	Independent Hydro - Net	273	269	267	269	276	279	275	260	253	257
22	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88	2.88
23	**Non-Hydro Renewable**	33.0	19.8	1.90	0	0	0	0	0	0	0
24	Wind - Net	33.0	19.8	1.90	0	0	0	0	0	0	0
25	Other - Net	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	1116	994	1116	994	1116	994	1116	994	1116	994
27	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
28	**Contract Purchases**	209	102	102	99.2	91.3	80.7	77.6	77.0	77.5	77.3
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
30	Intra-Regional Transfers (In)	107	0	0	0	0	0	0	0	0	0
31	Non-Federal CER	84.0	84.0	83.8	82.5	75.0	64.6	61.2	60.9	61.1	61.1
32	Slice Transmission Loss Return	17.3	16.9	17.2	15.8	15.3	15.1	15.4	15.0	15.4	15.2
33	**Reserves & Losses**	-455	-448	-451	-447	-451	-447	-451	-446	-451	-447
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-232	-225	-228	-224	-228	-224	-228	-223	-228	-225
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**7532**	**7283**	**7392**	**7270**	**7391**	**7250**	**7387**	**7214**	**7378**	**7275**
39	**Total Surplus/Deficit**	**-426**	**-622**	**-580**	**-778**	**-701**	**-846**	**-768**	**-988**	**-876**	**-1012**

Exhibit 4-2: Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2026, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2026 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/16/2025**
S268-WB-20250415-174748

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	5284	5250	4639	4843	5337	6325	6337	5969	5478	5171	5171	5076	5244	5640	5443
2	Preference Customers	4802	4761	4219	4570	5166	6136	6140	5757	5250	4771	4771	4600	4733	5048	5096
3	Federal Agencies	140	139	116	140	167	185	188	199	171	145	145	130	129	148	155
4	USBR	342	350	304	133	3.79	3.73	8.80	13.3	56.9	255	255	345	382	444	192
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	367	365	610	519	847	848	929	874	829	413	413	148	21.3	333	560
7	Tier 1 Block	367	365	610	519	847	848	929	874	829	413	413	148	21.3	333	560
8	**Slice**	1461	1356	1323	1210	1478	1644	1702	1561	1508	1305	1265	1462	1485	1380	1454
9	Slice Block	615	615	602	554	613	701	696	664	628	594	594	536	546	582	611
10	Slice Output from T1 System	846	741	721	656	865	943	1006	896	879	711	671	926	940	798	843
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	1045	1105	733	543	545	546	346	347	342	343	343	341	343	366	491
14	Exports	485	550	376	305	305	305	305	305	305	305	305	305	305	328	331
15	Intra-Regional Transfers (Out)	561	554	357	238	240	241	41.3	42.0	37.4	38.3	38.3	36.3	38.3	37.4	160
16	**NR Obligation**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	NR Rate Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	**Total Firm Obligations**	**8169**	**8087**	**7315**	**7126**	**8218**	**9374**	**9325**	**8762**	**8168**	**7242**	**7202**	**7038**	**7104**	**7730**	**7958**
	Net Resources															
19	**Hydro**	6921	6078	5649	4912	6611	7300	7861	6903	6792	5504	5162	7492	7678	6520	6629
20	Regulated Hydro - Net	6587	5746	5356	4794	6268	7053	7564	6743	6613	5227	4883	7139	7275	6220	6354
21	Independent Hydro - Net	331	330	291	115	340	243	294	158	175	274	276	350	401	297	273
22	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
23	**Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
24	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
25	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
27	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
28	**Contract Purchases**	454	446	301	164	188	244	271	228	190	165	164	102	106	103	209
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
30	Intra-Regional Transfers (In)	350	350	200	64.5	88.3	139	164	125	89.0	64.4	64.4	0	0	0	107
31	Non-Federal CER	84.9	79.6	85.2	85.4	81.6	85.3	85.3	84.0	82.3	84.9	84.9	81.8	84.9	85.3	84
32	Slice Transmission Loss Return	17.6	15.4	14.7	13.3	17.6	19.2	20.5	18.2	17.9	14.5	13.7	18.8	19.6	16.6	17
33	**Reserves & Losses**	-483	-458	-426	-400	-450	-470	-486	-458	-454	-418	-409	-474	-498	-461	-455
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-260	-235	-203	-177	-227	-248	-263	-235	-231	-195	-186	-251	-275	-238	-232
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**8030**	**7216**	**6672**	**5818**	**7501**	**8217**	**8777**	**7814**	**7672**	**6418**	**6076**	**8281**	**8446**	**7322**	**7532**
39	**Total Surplus/Deficit**	**-139**	**-871**	**-643**	**-1,308**	**-716**	**-1,157**	**-549**	**-948**	**-497**	**-825**	**-1,127**	**1,243**	**1,342**	**-408**	**-426**

Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2026

Federal Report Surplus Deficit By Water Year
Operating Year 2026
White Book 2025 (Energy Only) Report Date: **4/17/2025**
S268-WB-20250415-174748

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Federal Report Surplus Deficit	154	822	-665	-1308	-686	-17.5	77.7	-112	204	584	1923	2195	1794	41.1	274
2	1990 Federal Report Surplus Deficit	112	-546	-365	-866	-270	1921	1303	2785	805	1017	1798	1998	4095	3316	1314
3	1991 Federal Report Surplus Deficit	2618	2020	1.61	-1443	1533	2041	2826	3837	1752	1703	975	2249	3351	4151	1985
4	1992 Federal Report Surplus Deficit	3140	1568	-432	-1231	-198	-1157	-423	-464	-366	-679	-1092	1900	1204	-704	-31.6
5	1993 Federal Report Surplus Deficit	147	-580	-390	-1308	-516	-1212	-1141	-2361	-505	277	-1498	2604	2547	1172	-149
6	1994 Federal Report Surplus Deficit	860	-126	-6.29	-1385	-325	-1236	-878	-493	-364	-1140	161	1415	1342	-289	-198
7	1995 Federal Report Surplus Deficit	96.1	-850	-238	-1265	-606	-740	572	1729	1764	39.2	-337	1447	3637	2401	671
8	1996 Federal Report Surplus Deficit	1672	345	193	-281	2554	5131	5418	5883	5309	1988	3031	3002	4581	4446	3299
9	1997 Federal Report Surplus Deficit	2858	1238	309	-1035	-8.05	2120	5484	5729	4739	2525	4026	4257	5141	4376	3021
10	1998 Federal Report Surplus Deficit	3337	2881	1136	1094	1394	946	1289	2058	1129	-169	-432	3844	4196	2498	1867
11	1999 Federal Report Surplus Deficit	2990	805	-2.69	-1188	-716	1110	4133	4305	4045	1192	1998	2193	4061	4666	2164
12	2000 Federal Report Surplus Deficit	4518	3599	288	-695	1470	2608	2443	2159	2240	2020	2156	2332	1828	1821	1888
13	2001 Federal Report Surplus Deficit	2183	-697	-287	-1192	-597	-699	-1054	-948	-930	-1149	-2211	257	363	-408	-536
14	2002 Federal Report Surplus Deficit	462	-750	-668	-1640	-968	-1225	-549	-25.6	-497	397	1993	2178	4033	3724	448
15	2003 Federal Report Surplus Deficit	904	45.7	-195	-1214	-140	-883	-363	-1345	1034	768	1105	1649	3292	-157	261
16	2004 Federal Report Surplus Deficit	-575	-930	-591	-1162	-26.5	-308	87.0	-138	-328	-42.7	-56.5	1243	2559	421	76.6
17	2005 Federal Report Surplus Deficit	-226	16.2	128	-564	183	1214	928	893	291	-930	-926	1454	2339	1341	598
18	2006 Federal Report Surplus Deficit	463	-684	-359	-995	-156	872	3118	3523	942	3088	1663	3584	3977	1930	1541
19	2007 Federal Report Surplus Deficit	546	-649	-489	-1070	-530	1148	2335	2027	2565	1851	801	1882	2847	1533	1121
20	2008 Federal Report Surplus Deficit	343	-826	-643	-915	-60.7	341	133	312	38.5	-427	-1127	2239	4611	3004	670
21	2009 Federal Report Surplus Deficit	1431	1410	-30.3	-962	-620	-191	1713	-29.5	-107	1668	922	1841	2468	-231	549
22	2010 Federal Report Surplus Deficit	-153	-1150	-426	-1045	-219	-672	-203	-1508	-1179	-825	-1433	338	3941	1770	-78.5
23	2011 Federal Report Surplus Deficit	879	-97.8	-33.5	-1072	-610	972	4196	4877	2681	3903	659	2640	5093	5237	2203
24	2012 Federal Report Surplus Deficit	4061	1884	9.12	-1137	-466	743	2355	2190	2531	3319	3263	3106	4661	4871	2092
25	2013 Federal Report Surplus Deficit	3353	2189	-113	-889	141	2757	1086	255	484	2920	1444	2449	3511	2180	1409
26	2014 Federal Report Surplus Deficit	1261	-222	69.9	-1142	-313	-36.0	1699	-183	3035	2762	1275	2435	3808	3014	1251
27	2015 Federal Report Surplus Deficit	1315	-152	9.55	-1113	277	2043	3289	3592	4314	1334	-510	444	748	-1139	1107
28	2016 Federal Report Surplus Deficit	-61.9	-920	-743	-934	-773	81.6	847	361	2197	2389	2229	2543	1918	-728	548
29	2017 Federal Report Surplus Deficit	-139	-871	-305	-448	2065	802	3423	3994	5561	4360	3161	3737	4597	1861	2362
30	2018 Federal Report Surplus Deficit	1787	298	-331	-1035	-1047	90.1	3624	4850	2734	2500	1521	3959	4021	1235	1741

SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/ Deficit: Operating Years 2026 – 2035, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2026 to 2035 Percentile: 10
White Book 2025 (Energy Only) Report Date: **4/17/2025**
S268-WB-20250415-174748

	Energy-aMW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Regional Loads										
1	**Retail Loads**	25380	25871	26382	26944	27481	28059	28496	28883	29057	29203
2	Federal Agency	157	161	164	170	174	177	178	181	183	185
3	USBR	192	192	194	197	197	197	197	197	197	197
4	Cooperative	3624	3948	4336	4724	5124	5560	5875	6109	6171	6212
5	Municipality	2582	2597	2613	2629	2648	2666	2675	2682	2687	2693
6	Public Utility District	5158	5249	5293	5359	5424	5491	5551	5620	5670	5709
7	Investor-Owned Utility	13617	13673	13730	13813	13864	13917	13968	14042	14096	14154
8	Direct-Service Industry	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	814	800	800	798	769	468	373	373	373	373
11	Canada	319	317	318	317	290	237	237	237	238	237
12	East Continental Divide	3.33	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	491	482	481	479	477	230	134	135	135	135
14	**Total Regional Loads**	**26194**	**26671**	**27182**	**27742**	**28250**	**28526**	**28869**	**29255**	**29430**	**29575**
	Regional Resources										
15	**Hydro**	12013	11971	12005	11991	12085	12056	12094	12130	12048	12235
16	Regulated Hydro - Net	10848	10813	10839	10834	10904	10884	10914	10938	10868	11036
17	Independent Hydro - Net	922	914	923	913	938	928	937	948	937	955
18	Small Hydro - Net	244	244	243	244	244	244	243	244	244	244
19	**Non-Hydro Renewable**	2907	2907	2906	2908	2907	2891	2902	2907	2907	2907
20	Wind - Net	2240	2240	2238	2240	2240	2224	2235	2240	2240	2240
21	Solar - Net	510	510	510	510	510	510	510	510	510	510
22	Other - Net	157	157	158	158	157	157	157	157	157	157
23	**Thermal**	12444	12176	12198	12103	12280	12029	12198	12158	12195	12090
24	Nuclear - Net	1116	994	1116	994	1116	994	1116	994	1116	994
25	Coal - Net	3201	3049	2955	2981	3034	2948	2962	3034	2948	2966
26	Natural Gas - Net	5371	5371	5373	5372	5368	5371	5372	5371	5371	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2730	2737	2729	2730	2737	2691	2722	2734	2734	2734
30	**Imports**	597	600	605	609	613	132	38.7	38.8	38.9	39.0
31	Canada	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4	36.4
32	Inland Southwest	509	513	517	521	525	93.6	0	0	0	0
33	Pacific Southwest	48.6	48.7	48.9	49.2	49.2	2.15	2.25	2.35	2.48	2.59
34	**Reserves & Losses**	-806	-798	-799	-796	-804	-782	-785	-786	-784	-787
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-806	-798	-799	-796	-804	-782	-785	-786	-784	-787
38	**Total Regional Resources**	**27153**	**26857**	**26914**	**26814**	**27080**	**26326**	**26447**	**26447**	**26404**	**26484**
39	**Total Surplus/Deficit**	**960**	**186**	**-269**	**-928**	**-1169**	**-2200**	**-2422**	**-2808**	**-3026**	**-3091**

Exhibit 5-2: Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2026, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile

Operating Year: 2026 Percentile: 10

White Book 2025 (Energy Only) Report Date: **4/16/2025**

S268-WB-20250415-174748

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Regional Loads															
1	**Retail Loads**	25467	25297	22727	23290	25177	28933	28409	27368	25206	23672	23672	23250	24863	26315	25380
2	Federal Agency	144	143	120	144	167	185	188	199	171	149	149	134	133	152	157
3	USBR	342	350	304	133	3.79	3.73	8.80	13.3	56.9	255	255	345	382	444	192
4	Cooperative	3415	3397	3104	3406	3601	4037	4023	3849	3639	3503	3503	3471	3642	3805	3624
5	Municipality	2379	2357	2241	2408	2698	3103	3123	2981	2729	2458	2458	2261	2253	2373	2582
6	Public Utility District	4854	4820	4468	4733	5302	6020	6008	5765	5268	4930	4930	4674	4851	5061	5158
7	Investor-Owned Utility	14284	14180	12441	12413	13352	15532	15006	14509	13291	12326	12326	12315	13552	14430	13617
8	Direct-Service Industry	50.2	50.1	50.9	51.8	52.2	51.9	52.3	52.0	51.5	51.9	51.9	50.4	50.1	50.1	51
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Exports**	978	1190	969	642	777	665	498	623	671	959	863	901	948	1065	814
11	Canada	411	481	305	305	305	305	305	305	305	305	305	305	305	328	319
12	East Continental Divide	15.4	14.5	14.9	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	3.3
13	Pacific Southwest	552	695	649	336	471	359	192	317	365	653	557	595	642	736	491
14	**Total Regional Loads**	**26445**	**26487**	**23696**	**23932**	**25954**	**29597**	**28907**	**27992**	**25876**	**24631**	**24536**	**24152**	**25811**	**27380**	**26194**
	Regional Resources															
15	**Hydro**	11278	10148	10313	8946	12350	13126	14067	11686	12234	10785	9998	14753	14029	11502	12013
16	Regulated Hydro - Net	10070	8947	9277	8137	11049	12024	12958	10821	11258	9667	8715	13210	12472	10238	10848
17	Independent Hydro - Net	883	878	791	646	1172	976	986	733	815	838	1001	1140	1134	859	922
18	Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19	**Non-Hydro Renewable**	2411	3185	2867	2346	2933	2271	1454	2172	2525	4089	3558	3866	3942	3862	2907
20	Wind - Net	1593	2340	2162	1744	2430	1871	1047	1663	1897	3314	2802	3026	3049	2954	2240
21	Solar - Net	658	686	548	443	344	242	259	351	470	619	599	692	759	727	510
22	Other - Net	159	159	157	160	159	159	148	158	158	157	157	149	134	181	157
23	**Thermal**	13426	13433	13492	13523	13713	13218	13059	12992	12160	11440	9713	9373	11165	12644	12444
24	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116
25	Coal - Net	3821	3822	3825	3826	3824	3201	3082	3081	3029	2170	1974	2467	3095	3078	3201
26	Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3366	4262	5587	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29	Cogeneration - Net	2880	2880	2871	2838	2896	2955	2923	2918	2183	2644	2171	2398	2667	2837	2730
30	**Imports**	593	593	518	489	675	777	612	612	515	462	462	511	671	724	597
31	Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	39
32	Inland Southwest	571	571	501	466	454	491	461	476	451	430	430	480	631	695	509
33	Pacific Southwest	1.34	1.34	1.34	1.48	182	236	88.9	64.8	1.48	1.48	1.48	1.48	1.48	1.48	49
34	**Reserves & Losses**	-842	-832	-769	-716	-840	-832	-826	-777	-776	-758	-672	-807	-906	-873	-806
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-842	-832	-769	-716	-840	-832	-826	-777	-776	-758	-672	-807	-906	-873	-806
38	**Total Regional Resources**	**26866**	**26527**	**26420**	**24589**	**28832**	**28560**	**28366**	**26684**	**26659**	**26019**	**23060**	**27697**	**28901**	**27858**	**27153**
39	**Total Surplus/Deficit**	**421**	**40**	**2,724**	**657**	**2,878**	**-1,038**	**-541**	**-1,308**	**782**	**1,388**	**-1,476**	**3,545**	**3,090**	**479**	**960**

Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2026

Regional Report Surplus Deficit By Water Year

Operating Year 2026

White Book 2025 (Energy Only) Report Date: **4/24/2025**

S268-WB-20250415-174748

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1025	2618	2079	1392	2754	500	92.0	386	1991	4596	6076	5617	5078	1750	2403
2	1990 Regional Report Surplus Deficit	1066	715	2725	1407	3915	4503	3099	5195	3092	5247	5582	5075	8764	7415	4274
3	1991 Regional Report Surplus Deficit	5054	4858	3251	910	7404	4229	4478	7462	4754	6239	3297	5625	7505	9185	5356
4	1992 Regional Report Surplus Deficit	6114	4319	2721	620	3047	-1096	-446	346	887	1378	-1048	3749	2277	-298	1432
5	1993 Regional Report Surplus Deficit	498	170	2112	603	2394	-1864	-2415	-3415	1004	3985	-1281	6952	5642	3771	1395
6	1994 Regional Report Surplus Deficit	2677	1302	3275	545	2255	-1478	-1267	-344	1493	1111	2282	3746	2995	556	1286
7	1995 Regional Report Surplus Deficit	601	-87.4	2649	774	2287	-63.7	1159	4294	4990	2795	218	4561	8333	5801	3027
8	1996 Regional Report Surplus Deficit	4134	2069	3568	2891	9125	9729	9123	11452	10744	7609	8168	7461	9480	9519	7811
9	1997 Regional Report Surplus Deficit	5761	3763	3946	1557	3663	4602	9648	10372	10504	8310	9265	9865	11066	10010	7376
10	1998 Regional Report Surplus Deficit	7013	6642	5870	5983	6362	2654	2956	4630	4143	3199	978	8526	9168	6168	5450
11	1999 Regional Report Surplus Deficit	5828	2940	3502	901	2801	3324	7135	7915	8339	5313	5709	6622	10257	10787	5941
12	2000 Regional Report Surplus Deficit	8831	7795	3931	2006	7054	5718	4121	4533	5278	7166	6169	5978	5365	4936	5326
13	2001 Regional Report Surplus Deficit	4312	961	2778	1038	1950	-1029	-2354	-1360	-325	413	-3560	1480	1562	386	435
14	2002 Regional Report Surplus Deficit	958	-36.5	1633	-21.3	2150	-1113	-572	814	722	4058	5318	5553	9154	8249	2638
15	2003 Regional Report Surplus Deficit	2676	1435	2992	576	2648	-1156	12.3	-1160	3461	4050	2942	4017	6885	885	2063
16	2004 Regional Report Surplus Deficit	-440	-270	2138	1439	3223	163	11.3	442	1187	3209	1236	3449	5476	2125	1789
17	2005 Regional Report Surplus Deficit	281	1513	3791	2092	3654	2954	1711	1923	2050	1196	-426	3796	4902	3281	2621
18	2006 Regional Report Surplus Deficit	1418	129	2503	1251	3011	2164	5971	6498	3283	8346	5055	8333	9064	4754	4499
19	2007 Regional Report Surplus Deficit	1835	448	2444	915	3886	2820	3595	3979	6776	6637	3106	5063	6249	4073	3808
20	2008 Regional Report Surplus Deficit	1514	150	2657	1397	2839	1464	-286	966	1394	1380	-1566	6752	9954	7400	2944
21	2009 Regional Report Surplus Deficit	3664	3639	3082	1144	2535	-153	2735	468	945	5379	3166	5344	6506	1336	2658
22	2010 Regional Report Surplus Deficit	715	-265	2369	1189	3289	-624	108	-1815	-363	1281	-1508	1814	9201	5210	1714
23	2011 Regional Report Surplus Deficit	2514	1632	3232	1178	2624	2513	7337	8489	6797	10228	3437	7148	11360	11851	5930
24	2012 Regional Report Surplus Deficit	8424	5171	3610	1183	2731	1645	3891	4532	5982	8954	8253	7602	9879	10551	5581
25	2013 Regional Report Surplus Deficit	6390	5063	3256	1600	4242	5289	1384	924	2332	8275	3875	6240	7535	5166	4160
26	2014 Regional Report Surplus Deficit	2651	1160	3522	1226	2596	84.1	2663	588	6891	7415	4045	6381	7984	7262	3916
27	2015 Regional Report Surplus Deficit	3003	1307	3162	1298	4315	4592	5621	7177	8560	5436	-103	1074	1741	-1032	3416
28	2016 Regional Report Surplus Deficit	76.4	-343	2522	1110	2460	1339	1679	2084	5635	7326	5848	5752	3992	139	2756
29	2017 Regional Report Surplus Deficit	373	-31.7	2428	3210	7488	1801	4749	7944	11776	11183	7696	8847	10148	4815	6037
30	2018 Regional Report Surplus Deficit	4175	2015	2761	1528	2585	1095	6034	8666	6195	7782	5463	8600	8209	3808	4898

APPENDIX – REPORTS AVAILABLE UPON REQUEST

Please send request via email to WhtieBook@bpa.gov, and allow three to five business days for turn-around time.

A. Annual Energy (aMW) – Operating Years 2026 – 2035
B. Monthly Energy (aMW) – Operating Years 2026 – 2035

	Report #	
Report Descriptions	**Annual**	**Monthly**
Federal Report Surplus/ Deficit	1A	1B
Regional Report Surplus/ Deficit	2A	2B
Regional Total Retail Load	3A	3B
Regional Exports	4A	4B
Regional Imports	5A	5B
Regional Intra-Regional Transfer	6A	6B
BPA Sales to Preference and Legacy Customers	7A	7B
Regional Regulated Hydro	8A	8B
Regional Independent Hydro	9A	9B
Regional Small Hydro	10A	10B
Regional Non-Hydro Renewable – Wind	11A	11B
Regional Non-Hydro Renewable – Solar	12A	12B
Regional Non-Hydro Renewable – Other	13A	13B
Regional Thermal – Nuclear	14A	14B
Regional Thermal – Coal	15A	15B
Regional Thermal – Natural Gas	16A	16B
Regional Thermal – Petroleum	17A	17B
Regional Thermal – Biofuel	18A	18B
Regional Thermal – Cogeneration	19A	19B
Non-Federal CER Deliveries to BPA	20A	20B
Federal Report Surplus/ Deficit by 30 Water Year	--	21B
Regional Report Surplus/ Deficit by 30 Water Year	--	22B

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5429 ▪ May 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-143:
Bonneville Resource Plan (compiled 2022 & 2024)

BONNEVILLE POWER ADMINISTRATION

2022 Resource Program

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Section 1: Introduction

This report begins with a general overview, noting the purpose of the Bonneville Power Administrations' Resource Program, highlighting changes from previous assumptions and methodology, and summarizing key findings of the analyses. Following the overview is a more in-depth look at each component of the Resource Program, including the assumptions, methodologies and study results, along with a brief section on BPA's next steps culminating from the conclusions.

1.1 Overview

BPA launched its Resource Program shortly after passage of the Northwest Power Act in 1980 to assess the agency's need for power and reserves and to develop an acquisition strategy to meet those needs. The Resource Program study provides analysis and insight into long-term, least-cost power resource acquisition strategies. This study examines uncertainty in loads, water supply, resource availability and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations.

The 2022 Resource Program covers the fiscal years 2024 – 2033 and includes updates made to the optimization process and refreshes inputs. This study also includes a high policy scenario that will help BPA understand how the resource solution results may be impacted by changes in key assumptions such as loads, candidate resource costs and market prices. The results yield a vision of the agency's needs and low-cost resource strategies across a range of future market conditions and policy environments.

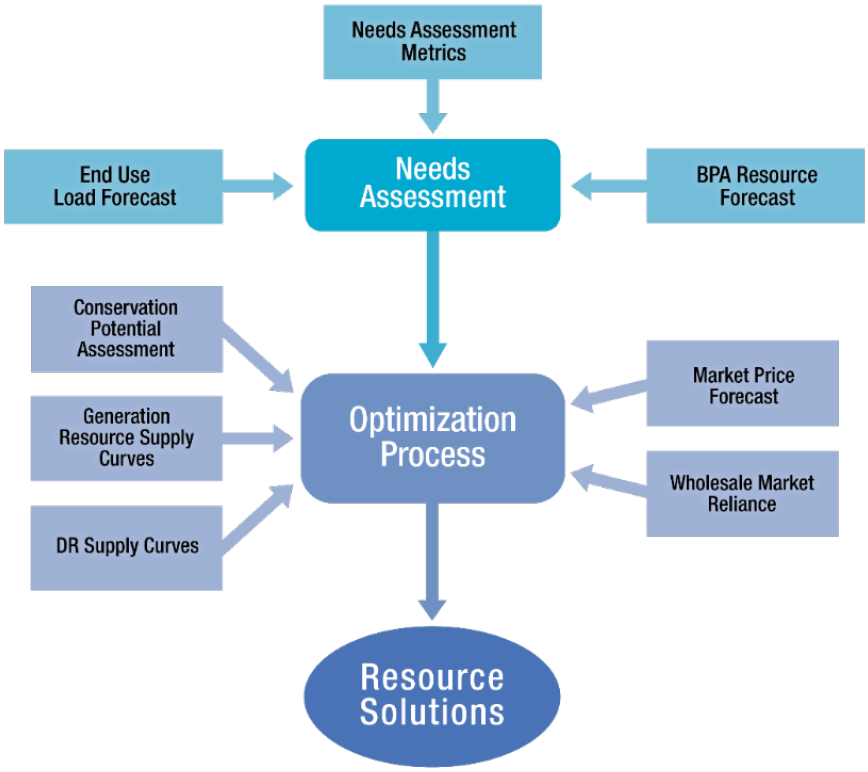
BPA's 2018-2023 Strategic Plan describes the actions it will take to remain a competitive supplier of low-cost power to its regional firm power customers. To support these strategic goals, the 2022 Resource Program details a comprehensive planning analysis that seeks to align BPA's resource acquisitions, including energy efficiency and demand response initiatives, with its long-term power supply needs.

The Resource Program is neither a decision document nor a process required by any external entity. Rather, it is a voluntary body of work, undertaken to inform acquisition strategies and provide valuable insight into how BPA can meet its obligations and strategic objectives at the least cost.

1.2 Methodology

The Resource Program begins with a forecast of BPA's obligations to supply firm power and the existing resources available to meet that demand, and then, determines any need for incremental energy or capacity in the Needs Assessment. The Resource Program next identifies and evaluates potential solutions to meeting those needs, including energy efficiency, demand response, candidate generating resources and power purchases. Finally, the Resource Program outlines potential strategies for meeting BPA's needs. Figure 1 provides a high-level diagram of the Resource Program process.

Figure 1: Resource Program Process



To assess the costs and benefits of resource solutions, BPA uses Aurora to create an electricity price forecast. Aurora is a computer software tool that can produce energy market price forecasts, value and uncertainty analyses, and automated system optimization. The energy market price forecast incorporates a natural gas price forecast, a renewables build forecast and assumptions around many other important factors, including regional generating resource retirements, negative price bidding activity and load forecasts for surrounding regions.

BPA also uses Aurora to perform a long-term capacity expansion and portfolio optimization analysis that assessed candidate resources' performances against 400 sets of potential future market conditions. The result of the optimization process is a set of 40 different portfolios that all meet Bonneville's needs at varying budget levels.

1.3 Conclusions

The below summarizes the main conclusions of the 2022 Resource Program:

- BPA has its greatest heavy load hour energy needs in October where large deficits are observed under low water conditions.
- By using a shorter historical period of streamflow record that represents the impacts of climate change on hydro generation, BPA expects more winter generation and less summer generation when compared to the use of a longer period of historical streamflows.
- BPA has surplus capacity in the winter and the summer, similar to the prior Resource Program.
- The expected market price for energy at the Mid-Columbia trading hub has increased over the market price forecast in the prior Resource Program.
- Similar to previous Resource Program findings, the least-cost mix of resources that will meet BPA's expected energy needs consists of conservation and energy purchased from the market. In addition, demand response was also included in the least-cost mix of resources for this Resource Program.

The following sections provide a more detailed look at the 2022 Resource Program. Additional files supporting the data sets shared in this report can be found at BPA's Resource Planning webpage.

Section 2: Needs Assessment

2.1 Overview

The Needs Assessment measures the federal system's[1] expected generating resource capabilities to meet projected load obligations under a range of conditions and timeframes for a 10-year study period, spanning fiscal years 2024-2033. The Needs Assessment studies occurred concurrently with a process to modernize the hydropower forecasts in the Bonneville Power Administration's long-term studies, as well as during a transition to using the 2020 modified streamflow data. BPA ultimately decided[2] to adopt the most recent 30 years of streamflow history, 1989-2018, in long-term forecasts rather than the historic 90-year record. BPA made this change in order to more realistically incorporate the impacts of climate change on federal system hydro generation.

As a result, the Needs Assessment reflects two streamflow sets: 1) the 2010 modified flows, which provide an 80-year period of record, hereafter "80-year study," and 2) the 2020 modified flows from which only 1989-2018 are used in the modeling, hereafter "30-year study." The 80-year study is included to help illustrate the change in energy and capacity positions due to climate impacts. However, the Resource Program analysis only carries the 30-year data forward into the optimization step of the process.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of federal system load obligations and resource capabilities.

Load obligations: BPA's Agency Load Forecasting system (ALF) produces load forecasts. ALF includes power sales contract obligations to public and federal agency customers and to the U.S. Bureau of Reclamation, as well as other contract obligations. ALF automatically includes projections of programmatic conservation savings expected to continue at levels established under current conservation programs. The Needs Assessment contains an ALF-produced frozen efficiency load forecast, which implements a combination of statistically adjusted end-use and econometric approaches. This means that historic energy efficiency achievement savings are projected forward in the load forecast, but the incremental conservation needed to meet the Northwest Power and Conservation Council's 2021 Northwest Power Plan targets are omitted from the load forecast.[3] ALF forecasting methodologies incorporate the most recent 15 years of regional temperatures, allowing the forecasts to incorporate the most recent climate trends. Also, the load forecast beyond the current Regional Dialogue contracts (post 2028) assumes no material contract election or rate structure differences from Regional Dialogue. ALF forecasts do not project additional temperature changes in the planning period.

Resources: BPA forecasts the resource capability using two computer models: 1) HYDSIM (Hydro System Simulator) for monthly and annual energy; and 2) Riverware for hourly energy and capacity. The models assess the resource capability to meet loads under expected load conditions and extreme temperature events over a range of possible water conditions and while meeting non-power requirements. The 80-

[1] Details on the federal system's generating capacity can be found in BPA's 2022 White Book.
[2] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/climate-change-update-to-the-long-term-hydro-generation-forecast-letter.pdf [Accessed: 29 Aug 2022]
[3] The incremental conservation needed to meet the 2021 Northwest Power Plan targets and used to mitigate the deficits identified in this Needs Assessment will be discussed in section 4.4 – Portfolio Optimization Results.

year HYDSIM study used in the Needs Assessment is consistent with BPA's BP-22 Rate Case Final Proposal with updated flexible spill operations. To incorporate the federal system contract purchases and non-hydro generation in the study, the Riverware model operates to an hourly Federal Residual Hydro Load. The Federal Residual Hydro Load is the hourly federal load obligations minus the hourly contract purchases and non-hydro generation.

This assessment does not model any internal or regional transmission[4] constraints that may limit the ability to deliver the modeled system generation to load.

2.3 Studies & Metrics

As mentioned in the overview, the Needs Assessment focuses on two studies developed for FY 2024 through FY 2033: 80-year and 30-year. Depending on the study, up to four metrics, including annual energy and different capacity studies, were used to determine the ability of the federal system's generating capability to meet obligations.

- 80-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 80-year study uses the 2010 modified streamflow data set, 1929-2008, and uses the 1937 water year as the critical, or firm, water condition.
- 30-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 30-year study uses streamflow data from the most recent 30 years, 1989-2018, of the 2020 modified streamflow records from 1929-2018, or 90 water years.

The Needs Assessment used the following four metrics:

1. Annual Energy: This metric focuses on federal system annual average energy surplus/deficits under 1937-critical, or firm, water conditions. Only the 80-year study was used for this metric as it contains the 1937 water year and was consistent with the prior definition of firm annual energy at the time studies were produced. Future needs assements will instead use the "P10-by-month" definition of firm, which was recently adopted (see footnote 2 above).
2. Monthly P10 Heavy Load Hour Energy: This metric evaluates the lowest 10th percentile-by-month, or P10, of federal system surplus/deficit over heavy load hours. HLH refers to hour ending 07 to 22, totaling 16 hours each day, Monday through Friday; the other eight hours each day, Saturday and Sunday, and North American Electric Reliability Corporation holidays are light load hours. Each month is analyzed independently.
3. Monthly P10 Super-Peak Energy: This metric evaluates the P10 of federal system surplus/deficits over the six peak load hours per weekday by month. Each month is analyzed independently.
4. 18-Hour Capacity: This metric analyzes the federal system's ability to meet the six peak load hours per day over a three-day extreme weather event. Depending on the weather event, load obligations are adjusted for additional heating or cooling loads, and median water conditions are assumed for hydro generation. Additionally, load obligations assume that Canada requests maximum Canadian Entitlement energy deliveries available under terms of the Columbia River Treaty. Generating resources assume that wind generation is zero. Similarly, generation forecasts for the summer analysis— month of August—includes a 10% reduction in the Columbia Generating Station's generating capability to account for heat impacts on the CGS's cooling system. The Needs Assesment uses 80 water years to analyze the distribution of outcomes under different streamflow conditions.

[4] For additional detail on transmission, see the Transmission supplement section of BPA's 2022 Resource Program.

2.4 Results

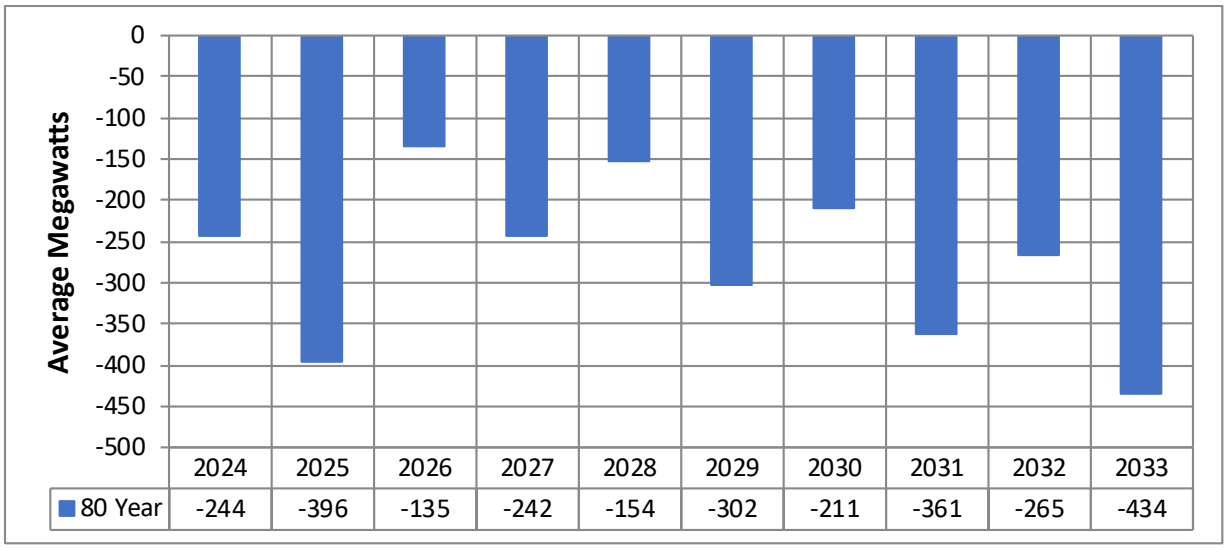
The Needs Assessment results show that the federal system has a wide range of potential deficits during the 10-year FY 2024-2033 period under the Annual Energy metric; see Figure 2. The Monthly P10 Heavy Load Hour metric shows larger deficits in October, January and the second half of April throughout the study period. The 30-year study shows less deficits in winter and more in August-October, consistent with trends of wetter, warmer winters and earlier streamflow recessions. Monthly P10 Super-Peak Energy metrics show deficits in the second half of April when low streamflows combine with significant increases in spill and restricted operating pools in the eight dams of the lower Columbia and Snake rivers; otherwise, the Super-Peak metric is surplus, and this result is consistent over the study period. Combined, the P10 HLH and Super-Peak metrics show that the system is generally able to serve the subset of six peak-load hours throughout the year under the low streamflow conditions, but the system is constrained for the full heavy load block in several months.

Lastly, the federal system is capacity surplus under the 18-Hour Capacity metric in both winter months (January) and summer months (August) when simulating increased loads due to extreme weather events. Previously, a single median water year was used to calculate this metric. Now, the full distribution of outcomes by water year is available. The distributions show that under the vast majority of water conditions, the system is able to serve the six peak-load hours each day during extreme weather over three consecutive days.

Annual Energy: The Annual Energy metric analyzes the ability of the federal system to meet energy loads on an annual basis.

80-year: Figure 2 shows a deficit of 244 average megawatts in FY 2024. The deficit grows to 396 aMW by FY 2025, recovers to 135 aMW in FY 2026, and then grows again to a deficit of 434 aMW by FY 2033. Hydro resources reflect the 2020 Columbia Rivers System Operations Environmental Impact Statement Preferred Alternative for the largest 14 federal dams. The difference between even and odd years is attributed to the Columbia Generating Station maintenance/refueling outage schedule. The decrease in deficit between FY 2025 to FY 2026 is due to the expiration of forward secondary surplus marketing activity that reduces obligations.

Figure 2: Annual Energy Surplus/Deficits – FY 2024 to FY 2033



Monthly P10 Heavy Load Hour Energy: Figure 3 presents the Monthly P10 HLH Energy metric for the 10-year study, and Figure 4 presents a selection of FY 2025-2026 to show the values in more detail. The metric analyzes the ability of the federal system to meet HLH loads on a monthly basis.

80-year: HLH energy deficits occur in the winter months as well as late summer; the largest deficit is in the second half of April. This result is consistent over the entire study period. Large monthly HLH energy surpluses occur in the spring, which coincide with the peak Columbia River Basin runoff.

30-year: The 30-year study presents similar results to the 80-year study, with deficits in April and over the winter months. March in the 30-year period changed to a surplus month, and the surplus in June decreased, consistent with earlier spring runoff. The 30-year study is also showing deeper deficits in the summer and fall consistent with earlier streamflow recessions.

Figure 3: P10 HLH Surplus/Deficits – FY 2024 to FY 2033

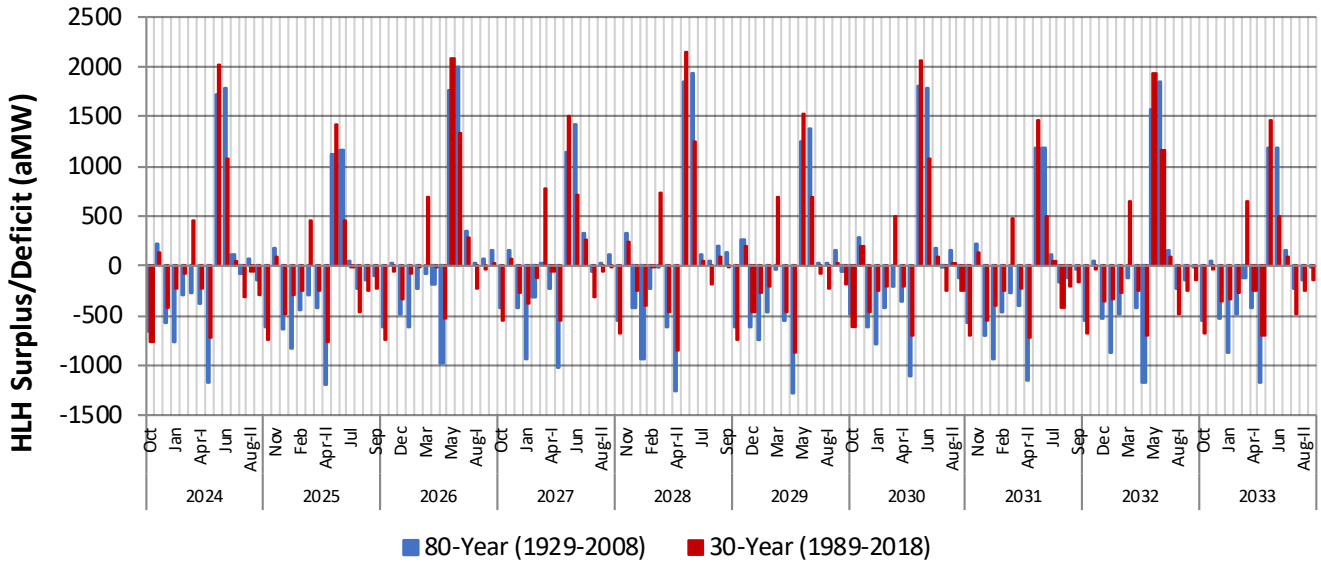
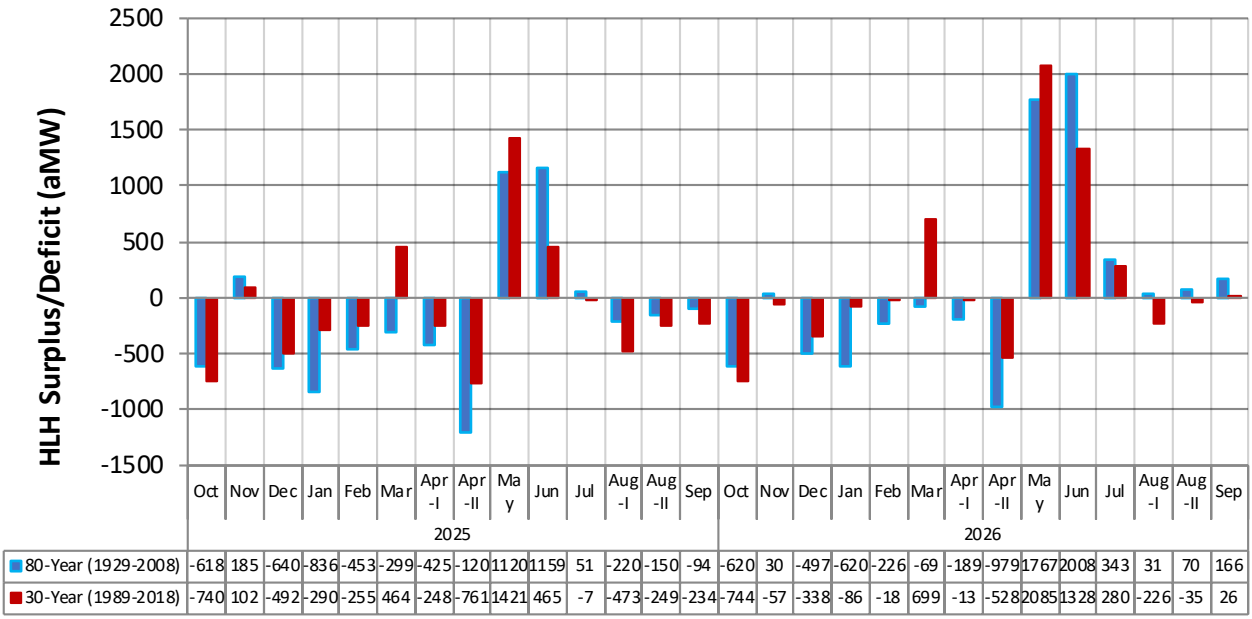


Figure 4: P10 HLH Surplus/Deficits – FY 2025 to FY 2026 (close-up look)



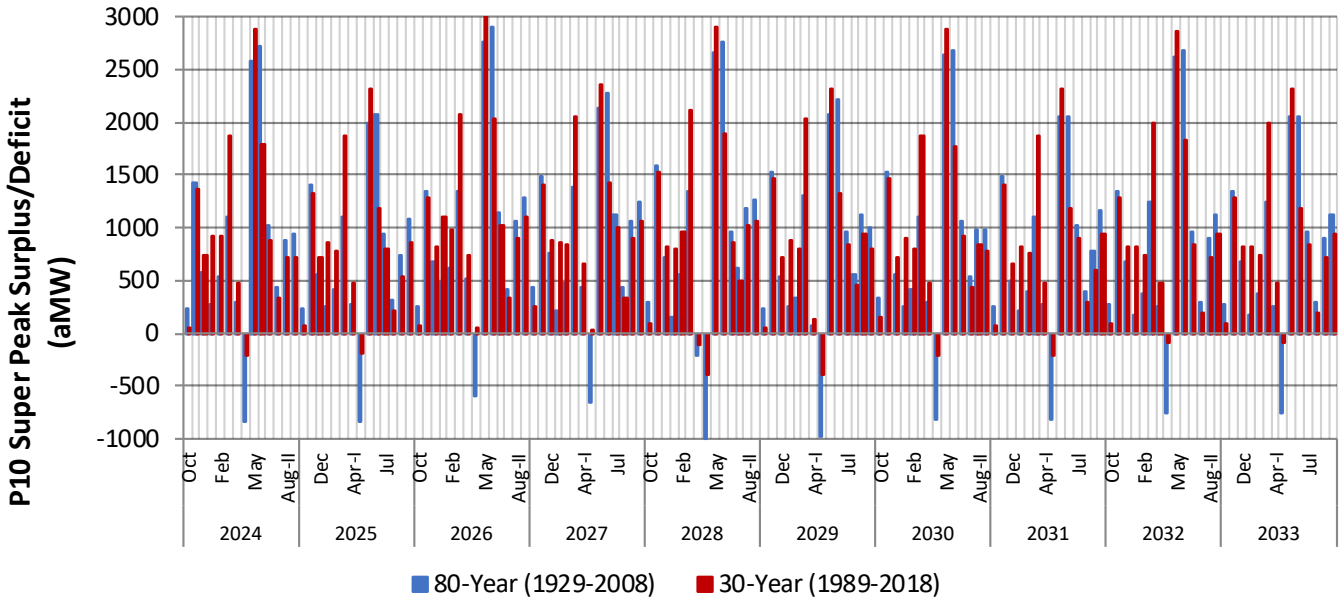
	Oct	Nov	Dec	Jan	Feb	Mar	Apr-I	Apr-II	May	Jun	Jul	Aug-I	Aug-II	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr-I	Apr-II	May	Jun	Jul	Aug-I	Aug-II	Sep
80-Year (1929-2008)	-618	185	-640	-836	-453	-299	-425	-120	1120	1159	51	-220	-150	-94	-620	30	-497	-620	-226	-69	-189	-979	1767	2008	343	31	70	166
30-Year (1989-2018)	-740	102	-492	-290	-255	464	-248	-761	1421	465	-7	-473	-249	-234	-744	-57	-338	-86	-18	699	-13	-528	2085	1328	280	-226	-35	26

Annual P10 Super-Peak Energy: Figure 5 shows the Monthly P10 Super-Peak Energy metric, which evaluates the ability of the federal system to meet loads over the six peak-load hours per weekday by month.

80-year: P10 Super-Peak resulted in annual surplus throughout the study period. Monthly analysis shows deficits in April.

30-year: The 30-year study reflects the same finding as the 80-year study, except the April deficit is smaller. The Super-Peak shows similar changes in results as the P10 HLH metric: surplus increases in winter, relative to the 80-year study, and decreases in the summer.

Figure 5: P10 Super Peak Surplus/Deficits – FY 2024 to FY 2033

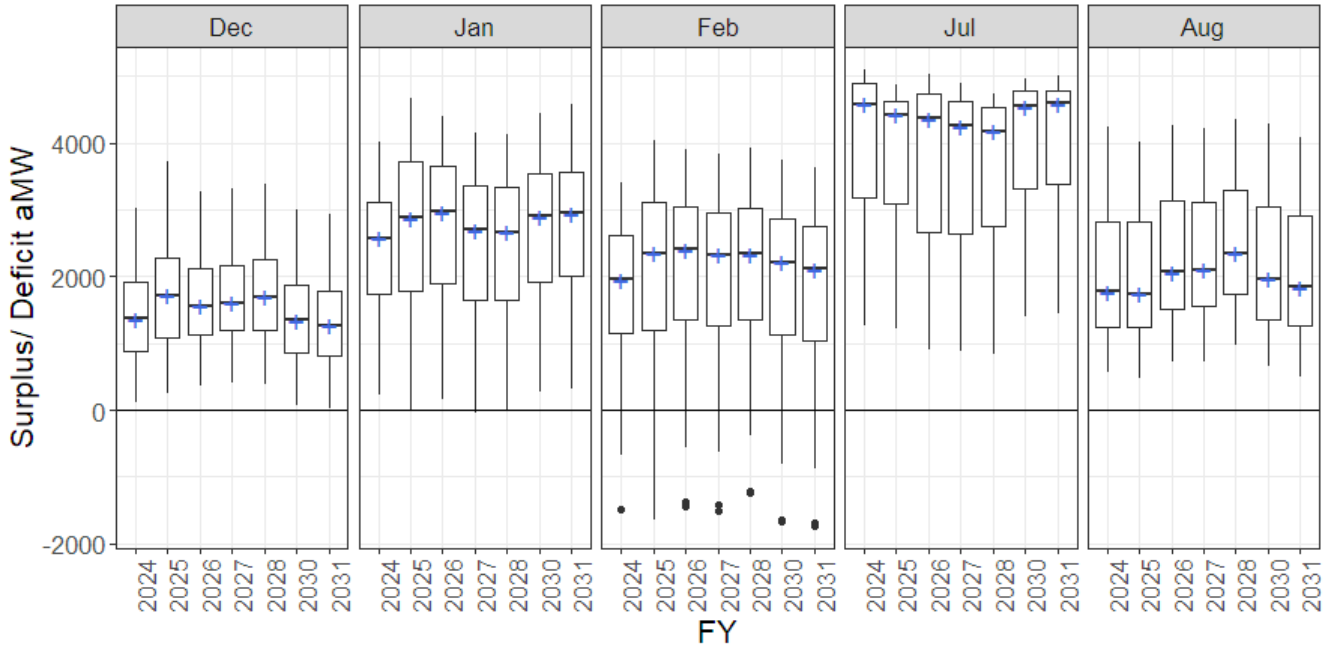


18-Hour Capacity: The 18-Hour Capacity metric analyzes the ability of the federal system to meet loads over the six peak-load hours per day during a three-day extreme weather event – a heat event during summer and cold event during winter – under median water conditions. Only the 80-year study was analyzed under this metric. The months of December, January and February were analyzed for winter seasons; the months of July and August were analyzed for summer seasons. In this Needs Assessment, the extreme weather condition can be viewed for all 80 years, instead of for only a specific year.

Figure 6 presents the distribution of results as boxplots with each end of the box representing the first quartile, or 25%, and third quartile, or 75%, of the data distribution; the middle bar with a blue (+) marks the median, or 50th percentile. The 50th percentile is used to represent the median water conditions for each month. The ends of the whiskers indicate the maximum and minimum data points, and the dark dots outside of the whisker ends are observations outside 1.5x the interquartile range from the bottom of the box, which are the outlier points.

80-year: Results show 18-Hour Capacity surplus/deficits for the winter (January) and summer (August) during the FY 2024-2033 period; however, there is no data for years 2029 and 2032 as unresolvable data issues were discovered. The 18-Hour capacity results show a range of surpluses between approximately 2,500 MW to almost 3,000 MW in the winter, and a range of roughly 1,700 MW to 2,300 MW in the summer over the study period.

Figure 6: Distributions of 18-Hour Capacity Surplus/Deficits



2.5 Conclusions

The current Needs Assessment shows that BPA would need to supplement existing federal system generation in order to meet existing and projected load obligations during the conditions modeled. With expected load growth, the federal system is projected to have annual energy deficits under critical water conditions across the study period.

Under low-water conditions, the federal system is projected to have HLH energy deficits, most notably in the winter and late summer, and to have surpluses under the Super-Peak and the 18-Hour Capacity metrics. The 18-Hour Capacity metric does not show constraints for either winter or summer seasons. Of the energy and capacity metrics analyzed, HLH energy is projected to have the largest deficits, and therefore, is the most constraining metric.

Under current climate change expectations, the federal system is projected to have lower HLH energy deficits or higher energy surpluses during the winter period. This is due to higher winter streamflows resulting from the warmer temperatures. Conversely, the federal system is projected to have higher HLH energy deficits in the summer due to lower summer streamflows.

Overall, the Needs Assessment results are consistent with that of the 2019 Needs Assessment results with respect to the P10 HLH metric deficits representing the most constrained periods and conditions for BPA to meet its obligations. BPA will continue to assess the need for additional generation based upon potential changes to environmental obligations, participation in the Western Resource Adequacy Program, and the loads placed upon BPA through the Provider of Choice process. Changes to the Needs Assessment in future Resource Programs will include an updated annual energy metric, which will be based on monthly P10 hydropower and potentially include enhancements to how capacity is modeled.

Section 3: Candidate Resource Assessment

3.1 Candidate Generating Resources

The 2022 Resource Program includes an expanded array of zero-emission resources and updated resource costs to reflect developments in renewable generation technologies after the publication of the 2020 Resource Program.

Resources are selected for the optimization based on technical availability within the region and over the study horizon; they are not pre-screened based on relative levelized costs of energy or capacity. The optimization process evaluates the value of expected generation and expected capital in addition to the operation costs of each resource.

The section below summarizes the resource plant types considered for the 2022 Resource Program.

- **Wind:** BPA modeled two types of wind resource, Columbia Basin onshore wind and Oregon coast offshore wind, using costs based on the U.S. Energy Information Administration, or EIA, Annual Energy Outlook,[5] estimates from the National Renewable Energy Laboratory, or NREL, and wind cost forecasts provided by consultants. For Columbia Basin wind, BPA estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with Aurora.
- **Solar:** Single-axis tracking utility-scale solar resource costs likewise reflect a blend of EIA, NREL, and consultant cost forecasts and include the latest information on tax credits and tariffs. BPA chose three representative solar generation shapes – southeast Idaho, south-central Washington, and Oregon west of the Portland metropolitan area – to reflect different possible solar output profiles in the BPA region, differing installation costs in metropolitan areas, and a list of locations provided by BPA Transmission Services that may benefit BPA's transmission system.
- **Paired solar and storage:** BPA added three solar and storage resources to the set of available resources for the 2022 Resource Program. The representative generation shapes for these resources are the same as above and are paired with a four-hour battery storage system where capacity is equal to half of the solar nameplate capacity.
- **Standalone six-hour battery storage:** BPA added one standalone battery storage option, modeled as a six-hour lithium-Ion battery system.
- **Zero-emission firm flexible resources:** BPA modeled two zero-emission firm flexible resource options with availability starting in 2028 and later. These resources are not intended to represent a specific generation type, but rather, provide a plausible cost trajectory for several types of zero- or net-zero emissions resources.
    - Base: High-fixed cost, low-variable cost resource. Modeled after small modular nuclear reactor characteristics; also comparable to a traditional fossil fuel base resource with carbon capture and sequestration.
    - Peaker: Low-fixed cost, high-variable cost resource. Modeled after a hydrogen combustion turbine with onsite electrolysis and storage; also comparable to combustion turbine running on other bio/renewable fuels or traditional resources.

[5] https://www.eia.gov/outlooks/aeo/

3.2 Conservation Supply Curves

3.2.1 Overview

Prior to the 2018 Resource Program, BPA had included conservation as a fixed input. In the past, a share of the conservation target from the Northwest Power and Conservation Council's Power Plan was assumed to be achieved by its public power customers. That amount of conservation was included as a predetermined resource that would be applied to meet BPA's needs. The remaining needs would then be met with other potential resources after accounting for expected savings from conservation.

Since the 2018 Resource Program enhancements, BPA now assesses conservation in line with other available supply and demand-side resources. An available amount of conservation is input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of conservation to be used in the optimization model, BPA relies on a conservation potential assessment (CPA). The CPA identifies the amount and costs of energy efficiency measures available from the forecasted customer loads supplied by BPA over the planning horizon. This ensures all potential conservation is included and evaluated against competing alternatives in the optimized selection process.[6] In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a CPA.

3.2.2 Adjusting for 2022 and 2023 Energy Efficiency Accomplishments

While the Resource Program's evaluation period begins with 2024, the load forecast developed by BPA for use in the Resource Program was developed in 2020 and does not incorporate future energy efficiency savings achieved by BPA and its customer utilities in 2020-2023. To ensure that the Resource Program properly accounted for BPA's loads and resources, BPA's Energy Efficiency Organization supplied the Resource Program team with adjustments to account for the additional savings that would be achieved in these years. The adjustments were provided as "must take" resources—resources the Resource Program was forced to select, since they reflected energy efficiency that would be accomplished by 2024.

For the portion of 2020 not included in BPA's load forecast and all of 2021, the Cadmus/Lighthouse team mapped BPA's actual accomplishments to load profiles and developed hourly inputs for the Resource Program.

For 2022 and 2023, the CPA potential was not provided to the Resource Program. In its place, the Cadmus/Lighthouse team provided hourly estimates based on BPA's overall expected level of savings mapped to different distributions of savings. Forecasts developed by BPA projected 37.85 average megawatts per year of energy efficiency. The Cadmus/Lighthouse team used the distribution of BPA programmatic achievements in 2021 to estimate the distribution of savings in 2022 and the distribution of CPA potential in 2024 below a levelized cost of $45 per megawatt hour for 2023.

Incorporating these adjustments developed a more accurate forecast for the potential conservation savings starting in 2024, the beginning of the 2022 Resource Program's evaluation period.

[6]The full CPA, including methodological discussion, is available on BPA's website: BPA-Conservation-Potential-Assessment-2022-2043.pdf

3.3 Demand Response Supply Curves

Since the 2018 Resource Program, BPA also assesses demand response equivalent to other available supply and demand-side resources. As with conservation, available amounts of demand response are input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of demand response to be used in the optimization model, BPA relies on a demand response potential assessment (DRPA). The DRPA ensures all potential demand response is included and evaluated against competing alternatives in the optimized selection process.

In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a DRPA. The assessment identified 19 DR products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on BPA's website[7].

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used Aurora with the Western Interconnection, a zonal topology, to generate a 10-year forecast of Mid-Columbia prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts sampled two weeks per month.[8] Each of the 400 forecasts is based on a unique water year sequence, natural gas price forecast, Western Electricity Coordinating Council-wide load forecast, hourly wind generation pattern, Columbia Generating Station outages schedule and hourly transmission path rating, as applied to the alternating current, direct current and British Columbia-United States interties. The price at a given energy hub is determined by the cost of delivering an incremental megawatt of energy to load, including transmission costs and energy losses, provided by the least-cost available resource.

The WECC load forecast is consistent with BPA's 2020 baseline projection, except for California, which has been updated to be consistent with California Energy Commission's 2019 Integrated Energy Policy Report's Mid Demand-Mid Available and Achievable Load Forecasts.[9]

Natural gas prices are typically a significant determinant of electricity prices because gas generators tend to be the marginal unit, or the least-cost generator available to supply an incremental unit of energy, and the price of natural gas is the predominant factor affecting the dispatch, or production, cost of natural gas-fired generators. Relative to the 2020 Resource Program, there were modest declines in projected natural gas prices over the forecast horizon. The declines are a result of the expectation for plentiful production of low-cost associated gas produced by oil-focused extraction activity.

Several processes inform BPA's forecast of WECC-wide resource retirements and builds used in the price forecast and market depth studies. First, data from the EIA's database of planned and sited resource additions and retirements over the horizon of the BP-22 rate period were referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion

[7] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

[8] For more information about Aurora and the risk models employed to produce this forecast, see the Power Market Price Study and Documentation, BP-22-FS-Bonneville-04.

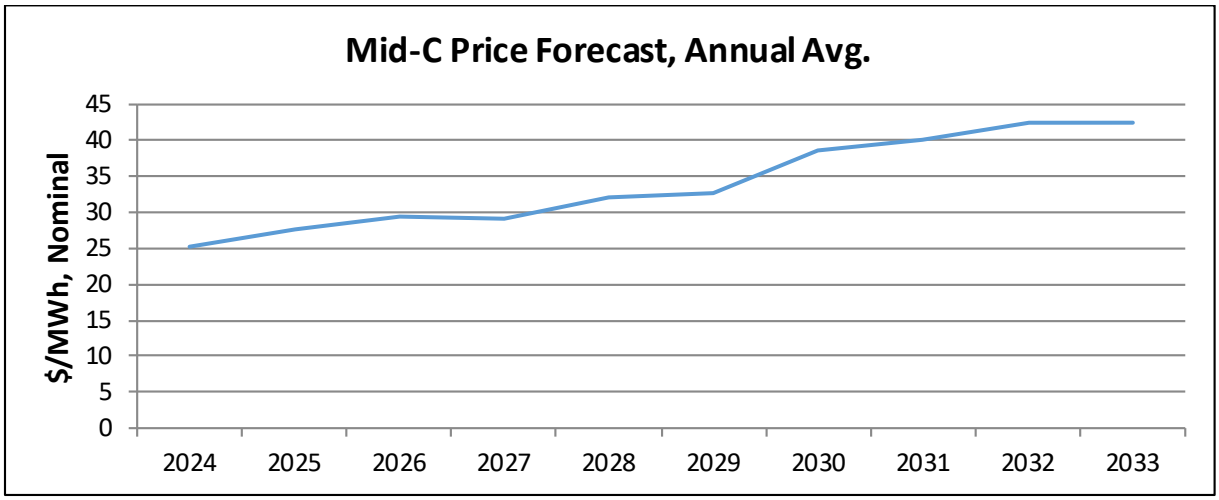
[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03, accessed Mar 2, 2021.

Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to update the default Aurora resource stack. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast and from integrated resource plans of utilities in the Southwest. Finally, the Aurora long-term capacity expansion model was used to build and retire additional resources based on economics to satisfy pool planning reserve margins and meet all relevant state, municipal and utility policies, including renewable portfolio standards, zero emission targets and electric sector emission caps.[10]

BPA's Aurora price forecast also adds two adjustments to resource bidding behavior that have substantial impacts on the resulting distributions of price forecasts. First, BPA runs Aurora using a recent historical period, i.e., 2014-2019, and calibrates thermal resource bidding behavior to better align Aurora prices with actual, day-ahead hub prices during the period. Second, BPA includes a simplistic depiction of negative bid behavior for renewable resources driven, for instance, by federal production tax credits for wind resources, renewable energy credits and power purchase agreements. All WECC renewable resources are given bid adjustments of about -$23 per megawatt-hour, which is nominal. These assumptions and additional modeling enhancements, such as the use of Aurora's commitment optimization logic, resulted in a distribution of price forecasts that is higher than the price distribution used in the previous Resource Program. The main driver for higher prices is the combination of a tighter resource buildout, where reliability requirements are just barely met, and the addition of calibrated thermal resource bidding behavior. Price increases are most acute in summer and winter months and in iterations with low hydro conditions.

The following figures depict the Mid-C price forecasts. Figure 7 shows an annual average price for all hours by year. Figure 8 presents average monthly prices for all hours by each month for the years 2024, 2028 and 2032. Figure 9 depicts prices averaged by hour for the years 2024, 2028 and 2032. Figure 10 is a comparison between the Mid-C price forecasts for the 2020 and 2022 Resource Programs for heavy load hours (HLH) and light load hours (LLH).

Figure 7



[10] State policy requirements within the WECC enacted as of July 1, 2021. Additional clean energy goals and policies at the municipal and utility level are included, but have been discounted by 20% to represent uncertainty about the extent to which these commitments will be upheld over the forecast horizon.

Figure 8

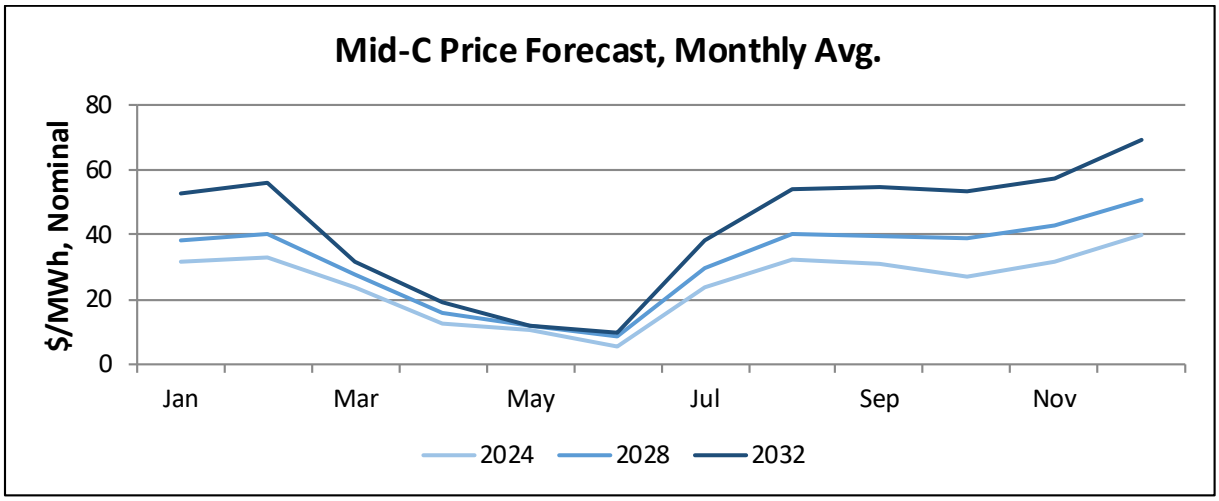


Figure 9

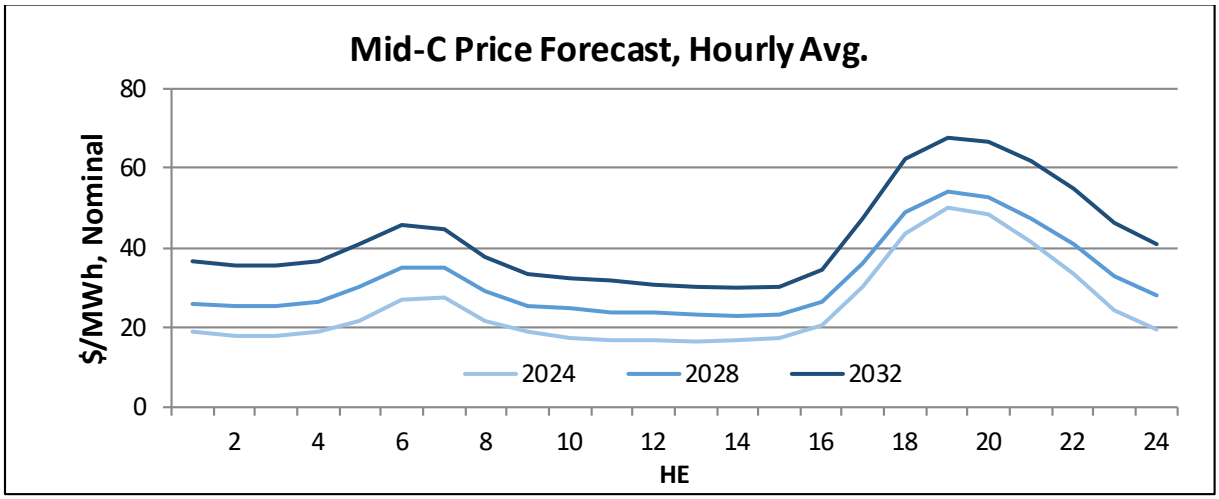
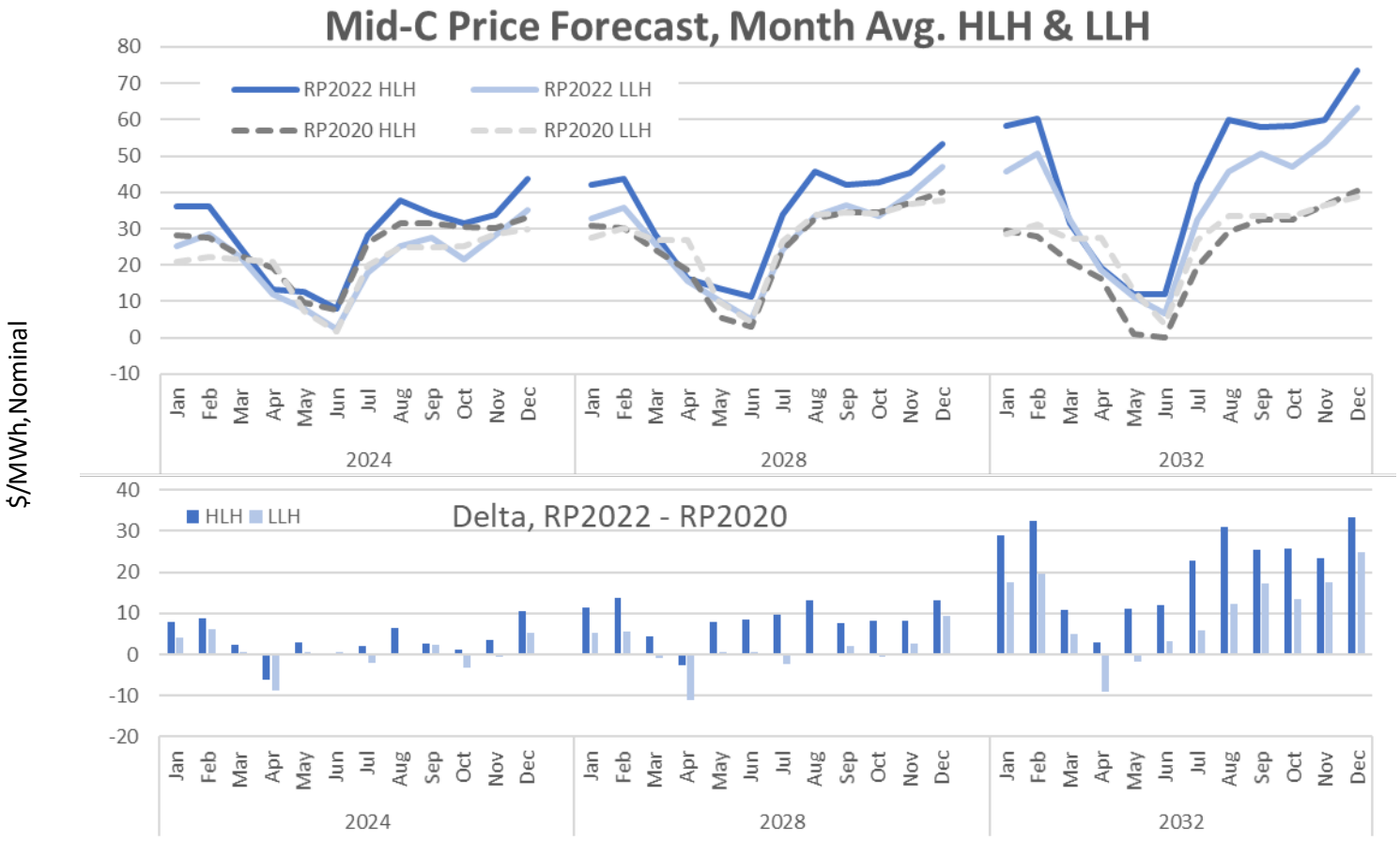


Figure 10



3.4.2 Market Reliance Limit

Given expected fundamental changes in energy markets across the WECC driven by growth in zero-emission resources, BPA used Aurora to assess future energy availability and establish monthly market reliance limits for the 10-year planning horizon. The process begins with a resource build assumed to reflect zero market reliance, i.e., all balancing authorities meet their reliability needs individually, without relying on other BAs or regions. Next, BPA uses incremental reductions in regional resources[11] to represent increases in market reliance. Higher levels of market reliance are tested until the exceedance of the 5% loss-of-load probability threshold. Up until that point, it is assumed that the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. BPA is then allocated a share of the market availability proportional to its share of regional load. This sets BPA's market reliance limit, expressed in terms of monthly average heavy-load-hour megawatts. It should be noted that this methodology does not anticipate or account for evolving market structures, such as wider adoption of an Energy Imbalance Market or a WECC-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

[11] Testing all combinations of resource removal would be computationally prohibitive; instead, BPA uses monthly flat load increases to represent the loss of resource availability.

Section 4: Resource Optimization

4.1 Overview

The Bonneville Power Administration uses Aurora to calculate least-cost and risk-reducing[12] resource options that satisfy its needs throughout the 10-year planning horizon. These portfolios further inform BPA's resource strategy, including information on the amount of Energy Efficiency Incentive funding, which may be invested over the upcoming rate period.

4.2 Long-term Capacity Expansion

The 2022 Resource Program added a resource optimization step using the Aurora long-term capacity expansion study type. This study uses an iterative mixed-integer program to solve for the least-cost set of resource options that meet BPA's 10th-percentile, or p10, heavy load hour needs. It does so at greater granularity than the portfolio optimization and ensures that existing resources and new selections are meeting system energy and capacity obligations, if present.

While the portfolio optimization study optimizes over the distribution of 400 traces at the monthly diurnal level, the long-term capacity expansion, or LTCE, uses hourly granularity for the resources available to meet BPA's p10 HLH obligations. This allows a more precise optimization of least-cost resource strategies while using more detailed market costs and availability, generation resource output profiles and cost, and energy-efficiency and demand-response savings profiles and costs. The least-cost resources built in the LTCE meet BPA's p10 HLH obligations and are then fed to the portfolio optimization study as "must-build" resources. The portfolio optimization will then evaluate these resources according to the varying loads, resources, market prices and applicable wind risk in each of the 400 traces in the input distribution. Portfolio optimization then uses the performance of each resource in each run to conduct the portfolio analysis.

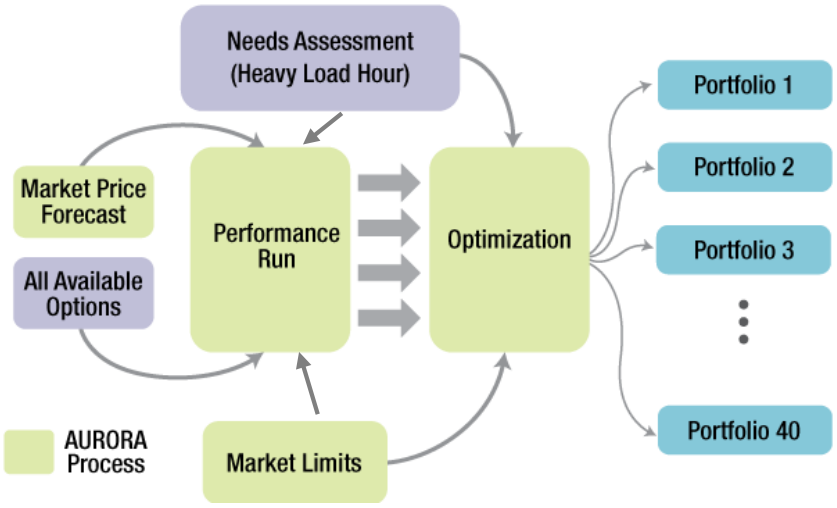
4.3 Portfolio Optimization

Figure 11 depicts the overall process and key inputs for the portfolio optimization study. Resource Program staff begin by evaluating all resource options discussed in Section 3 to assess their individual performance in each of the 400 sets of inputs. The 400 zonal runs, called the performance runs, each contain a different mix of needs, market prices, gas prices and wind risk and allow the portfolio optimization study to evaluate each resource according to those differing conditions.

Market reliance limits are also applied in the 400 zonal runs via a second zone that represents the Mid-C hub as well as transmission links between the BPA zone and the market zone that correspond to the monthly HLH market reliance limit. These limits also serve as constraints for the optimization step.

[12] "Risk" is defined here as variation of total portfolio costs across the 400 market price forecasts; see market price forecast, Section 3.4).

Figure 11



Aurora employs a linear optimization to jointly solve for the least-cost solution of meeting energy needs over the 10-year planning horizon – or Portfolio 1 – subject to market costs, market reliance limits and resource constraints. Portfolio 1 is selected by lowest average cost, over the 10-year study horizon, across the 400 price sets without considering the variance in portfolio cost across the 400 iterations. The model then solves for portfolios that minimize variation of total portfolio costs at progressively higher total portfolio cost levels on average.[13] The risk-minimizing portfolios can be thought of as hedges against market price volatility or streamflow conditions, or both. Each successive portfolio has a higher budget constraint and allows for the purchase of more resources that are not least-cost but provide greater insulation against market price swings or streamflow conditions.

This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 12. The frontier is efficient in the sense that at any given cost point, there is no other combination of available resources that would reduce the variation of total portfolio costs. Therefore, all portfolios above the efficient frontier are suboptimal because their costs can either be reduced without an increase in variance, or their variance can be reduced without an increase in cost. Alternatively, both cost and variance can be reduced to arrive at a better performing portfolio.

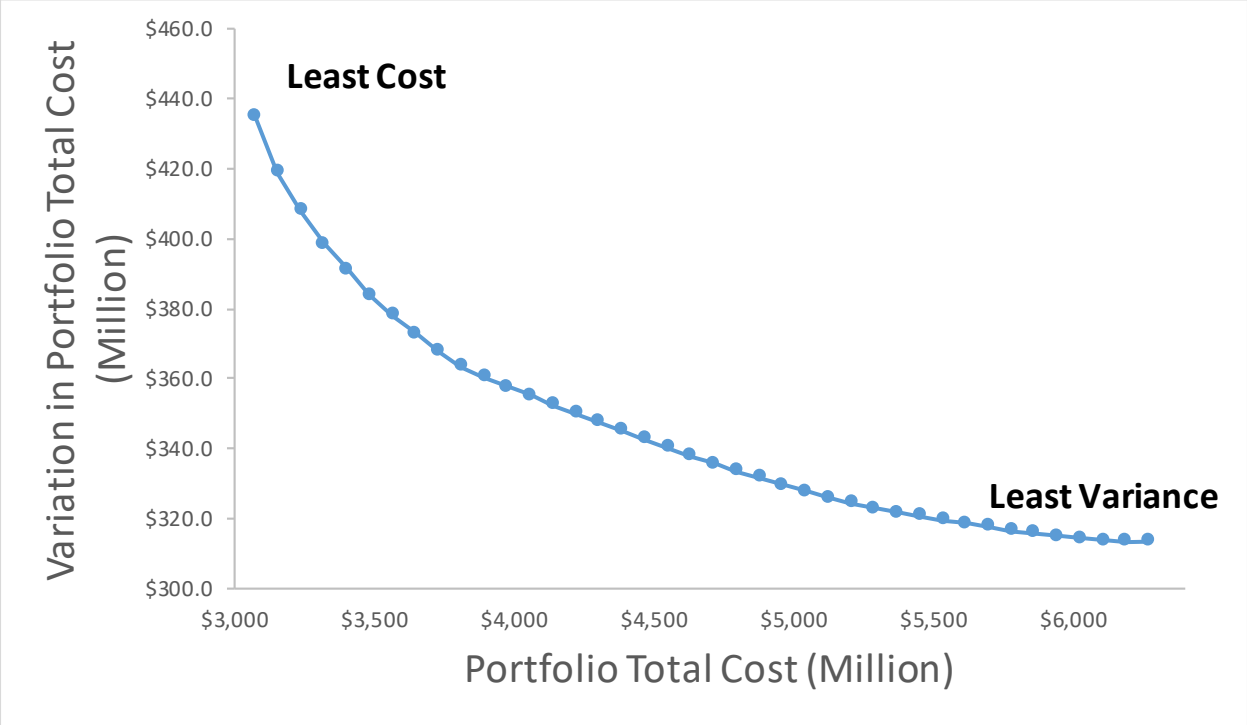
4.4 Portfolio Optimization Results

The Aurora portfolio optimization process produces an efficient frontier with 40 different resource portfolios. Figure 12 shows the model output of the 40 different portfolios for the 2022 Resource Program. These results are characterized by diminishing returns to the risk-reducing portfolios – the

[13] After finding the least-cost portfolio, the optimization model then solves for a portfolio with the lowest total cost variation, in terms of total portfolio cost standard deviation, without regard for total cost level, known as Portfolio 40. These two portfolios become end points of an efficiency curve. The range of average total portfolio cost is then split up according to the number of desired portfolios - BPA selected 40. For each point along this range, the optimization model solves for a portfolio of resources that minimizes total portfolio variation without exceeding that particular total cost level.

greatest reduction in variance is from the first portfolio to the second, and each successive portfolio achieves a smaller decrease than the last.

Figure 12



Given the changes in resource costs, BPA's loads and resources, the market prices forecast and market purchase limit, results have shifted from the 2020 Resource Program. The Resource Program team also made a number of improvements to the Aurora model that is used for the Resource Program analysis. The primary drivers of the difference from the prior Resource Program are as follows.

1. **Updated water years in the needs assessment:** The set of water years used to calculate BPA's p10 HLH needs has been updated since the prior Resource Program. The agency now bases its forecasts on the 30 water years between 1989 and 2018 rather than the 80 water years comprising the 1929 to 2008 period. This updated set of historical streamflows better captures the impacts of climate change on BPA's system and results in a shift of the monthly period with the greatest needs from January HLH to October HLH.
2. **Improved resource selection:** Refinements to the Aurora model for the 2022 Resource Program, in comparison to the 2020 Resource Program, allow resource selection in any year, rather than in one year, for energy efficiency and demand response, or two years, for generating resources. This allows the model to consider the cost effectiveness of each resource in each year, rather than the overall cost effectiveness of each resource across the entire study horizon. The main effect of this is that resource selections are lower in the initial years, approximately the same in the middle years, and substantially higher in the later years in comparison to the prior Resource Program as resource selections ramp up to meet load growth beyond 2029.
3. **Higher market price forecast:** On average, higher market prices make energy purchases more expensive and surplus energy more valuable. In general, because purchases tend to be made in expensive hours, higher market prices lead to higher overall portfolio total cost while also

increasing the opportunity for energy efficiency and demand response to be less expensive than market purchases.

In the basecase for the 2020 Resource Program, all 40 portfolios contained only energy efficiency and market purchases. For the 2022 Resource Program, in addition to energy efficiency and market purchases, demand response was also selected in all 40 portfolios, and generating resources were selected in portfolios two through 40.

Table 1 shows the energy efficiency acquisitions in the three lowest-cost portfolios. Compared to the 2020 Resource Program, energy efficiency acquisitions in the least-cost portfolio are slightly lower in the first two years of the 2022 Resource Program, but ramp up quickly, acquiring nearly 200 aMW more energy efficiency by the final year of the study than the 2020 Resource Program.

Table 1. Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	2-Year	4-Year	10-Year
1	96	223	723
2	103	242	785
3	105	245	787

Table 2 and Table 3 show the DR and generating resource selections in the three lowest-cost portfolios.

Table 2. Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	436	371	158	283	243
2	213	474	488	158	283	260
3	213	474	488	158	283	260

Table 3. Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	0	0	0	0	0
2	0	0	106	0	0	500
3	0	0	428	0	0	500

4.5 Conclusions

The resource solutions produced by portfolio optimization and detailed in section 4.4 indicate that the most economical solution for BPA to meet its energy obligations continues to be a combination of market purchases and demand-side resources. Energy efficiency and low-cost demand response were acquired in the least-cost portfolio up until it was as expensive as market purchases, and then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains BPA's preferred resource to meet identified energy needs.

The demand response resources were selected to meet short-duration energy needs in the months with the highest market prices. BPA did not identify a capacity need in the Needs Assessment, so these demand response resources are being dispatched to satisfy short-duration energy needs in the most expensive hours.

It is important to note that while the Needs Assessment looks at Bonneville's loads and resources in isolation, other regional studies have identified future capacity shortfalls in meeting the entire Pacific Northwest's load. BPA's system is expected to have surplus capacity, which is anticipated to become increasingly valuable as thermal generation continues to be retired from the grid in accordance with de-carbonizing legislative goals.

Additionally, the Needs Assessment does not analyze the use of the federal system to provide balancing services for variable energy resources. Instead, it specifically retains the federal system's capacity for service to BPA's statutory obligations. These and other issues are addressed in separate forums; the 2022 Resource Program results should not be viewed as representing the capacity needs for the entire region or any other specific entities within it.

Section 5: High Policy Scenario

5.1 Purpose

The Bonneville Power Administration modeled a high policy scenario in addition to the basecase. This scenario represents a plausible high electrification and decarbonization case while also providing a look at the least-cost resource builds that would be required to meet BPA's obligations in such a future.

The Resource Program team does not place any specific likelihood on the high policy scenario assumptions occurring. BPA will continue to monitor future load growth; should conditions such as those assumed in the high policy scenario begin to materialize, the high policy scenario enables the agency to adapt its resource strategies accordingly.

5.2 Assumptions

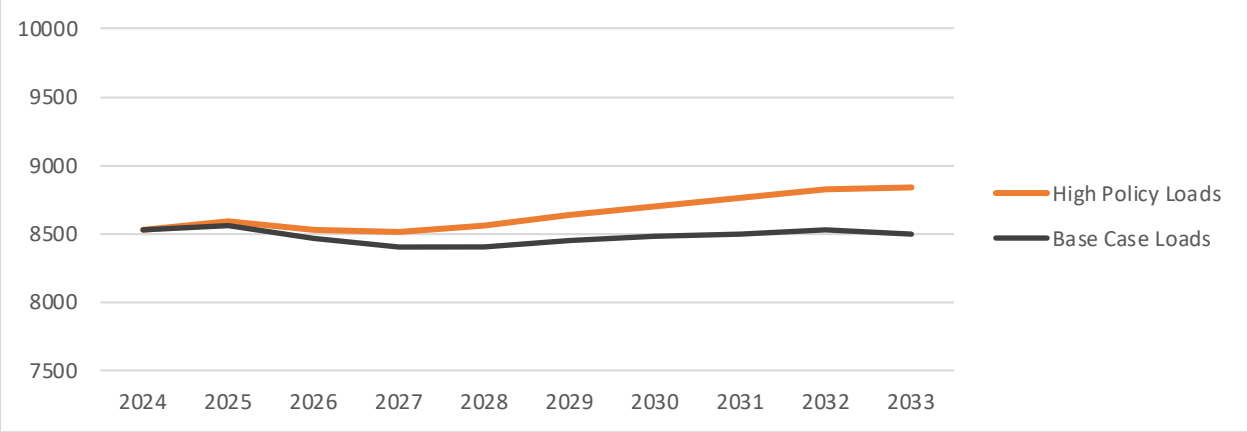
The high policy scenario represents a possible outcome given accelerated electrification and decarbonization policies in the western U.S. In this scenario, California carbon pricing is applied to Oregon and Washington, Western Electricity Coordinating Council-wide carbon pricing begins in 2030, and all states aim for 100% zero-emissions by 2050. Specific changes to the basecase assumptions are detailed below.

5.2.1 Obligations

The Resource Program team escalated the basecase distribution of BPA's monthly heavy load hour obligations using regional load growth rates provided by BPA Load Forecasting. The high policy load forecast assumed no change in the BPA customer base post-2028. It does assume accelerated adoption rates for electrification technologies and practices, such as electric vehicles, behind-the-meter solar and fuel switching from gas to electricity.

Excluding large new loads, which would be served at the New Resource rate, BPA estimated average annual growth of 0.43% over the study horizon. This results in roughly 4.5% growth over the basecase for the 10 years in the study horizon. The growth over the basecase is shown in Figure 13.

Figure 13



5.2.2 Resources

The Resource Program team made small reductions to the cost of renewable resources and battery storage for the high policy scenario. These adjustments reflect policies in the high policy scenario designed to facilitate the adoption of renewable generation and energy storage technologies.

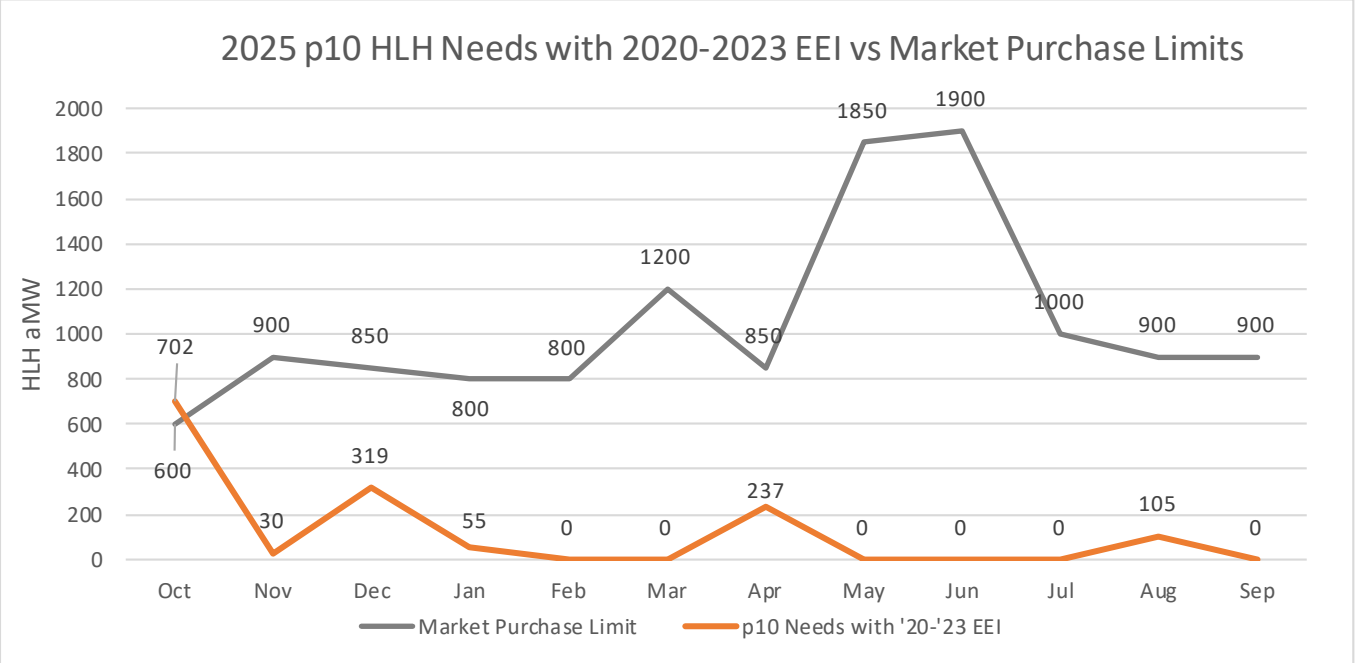
5.2.3 Market Prices and Limits

The policies associated with the high policy scenario result in a decrease in the overall market price forecast for the high policy scenario versus the basecase. Market prices are also lower in the high policy scenario during both January and October heavy load hours across the study horizon. January HLHs are typically characterized by higher-than-average market prices, and October HLHs have the greatest deficit between BPA's needs and market purchase availability. Periods with high market prices and periods with low market availability but high system needs will influence the resources selected in the portfolio analysis.

5.3 Results

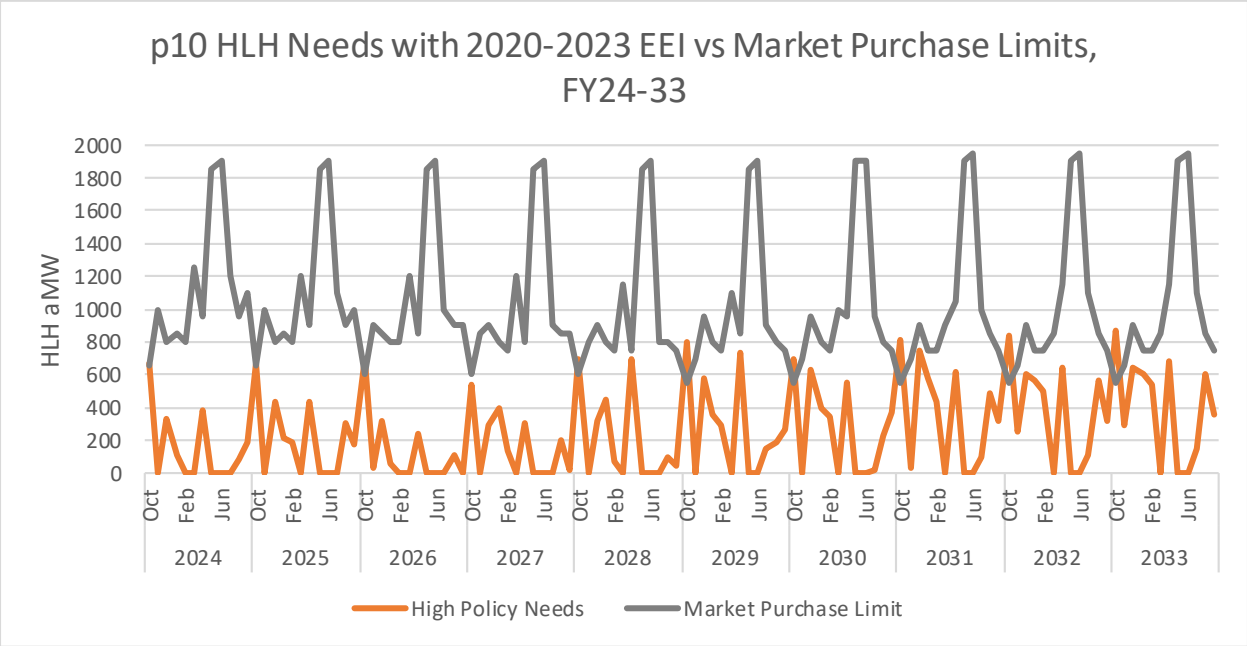
The increase in obligations for the high policy scenario caused the difference between BPA's October HLH needs and October HLH market purchase limit to increase to 102 average megawatts by fiscal year 2025, the second year of the study; see Figure 14.

Figure 14



This pattern continues later in the study, where the growth in BPA's obligations increases the difference between Bonneville's needs and the market purchase limit in every year from 2028 onward; see Figure 15.

Figure 15



Months where BPA's needs exceed the market purchase limit are months where the model will acquire resources above market purchases in the resource stack. It will have already acquired all resources that are cheaper than the market before moving to market purchases. Once the market purchase limit is exhausted, the optimization must add one or more resources that meet the remaining need for that month.

Table 4, Table 5 and Table 6 show the high policy scenario resource builds for conservation and generation resources for the three lowest-cost portfolios.

Table 4. High Policy Scenario Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	**2-Year**	**4-Year**	**10-Year**
1	95	221	696
2	98	229	755
3	102	238	786

Table 5. High Policy Scenario Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	437	373	176	336	269
2	213	475	490	176	336	283
3	213	513	492	176	336	303

Table 6. High Policy Scenario Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	31	31	42	42	42
2	0	31	31	212	212	462
3	0	56	105	250	250	750

5.4 Discussion and Comparison

Energy efficiency and demand response acquisitions in the high policy scenario are little changed from the basecase. In both cases, energy efficiency and demand response resources are acquired up to the point that the marginal resource is no cheaper than market purchases. The 102-aMW gap between the market purchase limit and BPA's needs in early FY 2025 is too sizeable to be filled with energy efficiency and demand response alone. This, coupled with the reduction in cost for renewable resources, led to the acquisition in 2025 of some additional winter demand response and a small amount of solar photovoltaic (PV) resources.

The continued growth of BPA's load obligations from 2027 onward also supports the acquisition of a small amount of generation with an output profile similar to offshore wind. The need to acquire generating resources in the early and middle years of the study period, combined with the lower market price forecast in the high policy scenario – which influences every resource's expected revenue – results in a small amount of substitution from energy efficiency to renewable generation compared to the basecase.

This substitution occurs mostly in the later years of the study. Up through 2029, there is little difference in energy efficiency acquisitions from the basecase. In 2029, energy efficiency acquisitions in the high policy scenario are just four aMW lower than the basecase. By 2033, energy efficiency acquisitions are roughly 25 aMW lower than in the basecase.

It is also worth noting that both the basecase and high policy scenario for the 2022 Resource Program have substantially higher energy efficiency acquisitions in the later years than in the 2020 Resource Program. The 2020 Resource Program acquired more energy efficiency in the first two years, nearly the same amount over four years, and a much lower amount overall than either scenario in the 2022 Resource Program.

In 2020, the least-cost portfolio contained just over 500 aMW of energy efficiency by the last year of

that study. In 2022, the basecase acquires approximately 215 aMW more energy efficiency over the study period, and the high policy scenario acquires 190 aMW more when compared to 2020. Table 7 below presents the least-cost portfolio for 2-, 4- and 10-year cumulative energy efficiency acquisitions from both resource programs.

Table 7: Comparison of 2022 Energy Efficiency Acquisitions to 2020 Resource Program

	2-year	4-year	10-year
2020 Resource Program	111	229	506
2022 Resource Program - Base	96	223	723
2022 Resource Program - High Policy	95	221	696

Section 6: Action Items

6.1 Next Steps

In the coming months, BPA will publish its Energy Efficiency Action Plan (Action Plan), describing its conservation goals, portfolio management strategy and program measures. The Action Plan will be informed by the Council's 2021 Power Plan, BPA's Resource Program and Integrated Program Review. BPA will also consider customer needs and other benefits of conservation such as capacity, resiliency and avoided emissions. During the Action Plan development process, low-cost flexible load management solutions that can be frequently deployed with minimal customer impacts will also be assessed.

Looking toward the next Resource Program, BPA plans to further develop and refine the enhancements it has made for the 2022 Resource Program, including updates to energy storage and demand response modeling, and refinements to the optimization process and risk analysis.

BPA will also monitor events that could change the forecasted outcomes of the 2022 Resource Program, such as new clean energy legislation, changes to resource costs or loads, or as yet unforeseen changes to the operations of the Federal Columbia River Power System. The impacts of these and other events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

Section 7: Transmission Supplement Summary

The Bonneville Power Administration's Transmission Services organization is instrumental to ensuring BPA Power Services' existing generating resources and market purchases are delivered to load in the BPA balancing authority area. Therefore, including a Transmission Supplement is intended to show the deliverability aspect, not just the generation aspect, of how BPA approaches resource adequacy for its obligations. BPA also relies heavily on other regional utility transmission providers to ensure that Power Services' load is served in balancing authority areas outside of BPA's. That portion of deliverability is not described in this Transmission Supplement.

If and when Power Services identifies and pursues the acquisition of resources other than energy efficiency and potentially demand response, Power Services would have to actively coordinate with Transmission Services. Such resource acquisitions are, however, unlikely in the near-term based on the results of the 2022 Resource Program analyses. Power Services and Transmission Services do actively coordinate and collaborate on near-term and long-term system planning activities, including model inputs, load forecasts, resource retirement estimates, and several other planning topics of mutual interest. Expanded active coordination would occur if Power Services resource acquisitions beyond demand side resources occurred. For a detailed description of Transmission's planning processes, read the Transmission Supplement attached in the Appendix.

Section 8: Appendix: Transmission Supplement Continued

This section was provided by the Bonneville Power Administration's Transmission Services organization. It describes the transmission planning process in Transmission Services and how the organization collaborates with BPA Power Services to serve the long-term transmission needs of network transmission, or NT, and point-to-point, or PTP, customers. It also describes how its available transfer capacity, also known as ATC or transmission inventory, is managed to respond to customer requests for long-term transmission service. Transmission Services and Power Services work and collaborate closely to manage the hydro resources of the Federal Columbia River Power System to serve the needs of BPA's NT customers. Besides Power Services, Transmission Services has a wide range of customers for PTP transmission services to deliver power from regional resources to many bulk electric power customers.

The chapter starts with an overview of BPA and its strategic objectives. It then reviews the trends Transmission Services believes will most affect its future: decarbonization, decentralization, technology, regulatory reform and regional cooperation. Each of these brings risks and opportunities to consider in the analytical, modeling and decision-making part of the process.

The analytical process starts with Transmission Planning having a good understanding of NT and PTP customers and their needs and load growth patterns. Transmission Planning also reviews resources, customers' technology, fuel prices, government policy and more. Forecasted loads and resources are the basis for transmission planning in addition to existing obligations and committed long-term firm transmission service.

Once the system conditions are defined, the analysis turns to developing corrective action plans for problem areas not meeting the applicable reliability standards. Finding solutions for these problem areas requires multiple analytical tracks: (a) consideration of non-wires solutions in cooperation with cross-agency organizations at BPA; and (b) coordination with Power Services and multiple organizations in Transmission Planning to collaborate on integrated solutions.

Once Transmission Services completes the system assessment, including the proposed transmission corrective action plans and flowgate ATCs, the capacity becomes eligible to meet the needs of BPA customers who submit Transmission Service Requests for transmission capacity for their loads and resources. The TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. In the cluster study, the network is analyzed to define reinforcements and non-wire solutions necessary to serve the TSR needs. Customers are then informed so they can make their project decisions, proceed to contract negotiations and ultimately to construction. Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups in Transmission Services and Power Services to achieve an efficient data collection, analytical evaluation and optimal recommendations.

8.1 Introduction

BPA energizes the region through more than 15,000 circuit miles, or 24,000 kilometers, of transmission lines and 261 substations in the Pacific Northwest, controlling approximately 75% of the high-voltage transmission system in the region. BPA also maintains interconnections with other regional power grids: British Columbia to the north; Rocky Mountains, Idaho and Montana to the east and southeast; and California to the south. BPA shares two interties with California: (a) the California-Oregon Intertie with

northern California utilities; and (b) the Pacific DC Intertie with the Los Angeles Department of Water and Power.

Transmission Services is dedicated to public service, and its mission is to deliver the best value for BPA customers and constituents as it acts in concert with others to ensure the Pacific Northwest has a transmission system that is prepared to integrate and transmit power from federal and non-federal generating units, provide service to BPA's customers, supply interregional interconnections, and maintain electric reliability and stability.

Transmission Services is an open access transmission provider that aligns its provision of transmission service with the Federal Energy Regulatory Commission's regulatory framework. The FERC framework is designed to prevent undue discrimination in providing access to wholesale transmission capacity. Transmission Services maintains an open access transmission tariff, and seeks to align its OATT with the FERC pro forma OATT to the maximum extent possible. The OATT process is flexible and allows for considerations from other governance structures.

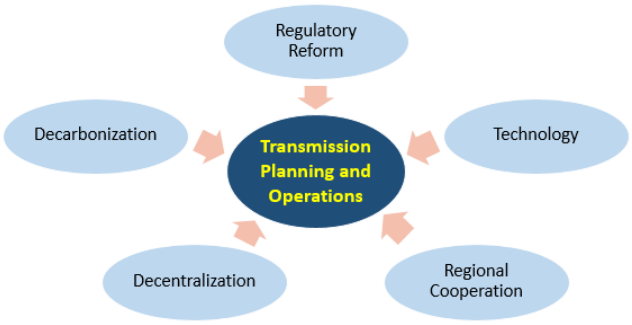
Transmission Services manages over 2,700 transmission service contracts that enable more than 30,000 transmission reservations and over 200,000 scheduling tags to be processed each month through BPA's commercial systems. Transmission's revenues are about $1.01 billion annually. Transmission Services provides transmission service to BPA Power Services customers, investor-owned utilities, independent power producers and any other business requiring the use of the Federal Columbia River Transmission System. Interested parties request transmission services and follow a well-defined process.

BPA's 2018 – 2023 strategic plan lists four agency objectives:

1. Strengthen financial health.
2. Modernize assets and system operations.
3. Provide competitive power products and services.
4. Meet transmission customer needs efficiently and responsively.

BPA's transmission objectives and strategies are based on its ability to deliver power efficiently and responsively.

Figure 8.1 – Major Trends Impacting Transmission



For 2022, Transmission Services continues to operate in a landscape of trends that started 10 to 15 years ago. The 2022 Resource Program incorporates the regional trend of new resources, such as wind – including offshore wind – and solar, and the continuing decline of coal generation, while hydro and natural gas continue to hold their share. The major trends for Transmission Services are:

- **Decarbonization:** The prevalent public policy of decarbonization from state regulators in the power and transportation industry has a variety of effects on BPA's future resource mix and load profile. The growth of variable solar and wind resources in the Northwest and California has already changed transmission operations relative to historic patterns, such as shifting the time of peak flows on some paths to be closer to sunset hours to manage the "duck curve" resulting from the ramping up of solar resources in California. BPA anticipates these trends to continue and likely become more pronounced as solar penetration continues to increase across the West. Decarbonization policies also influence the electrification of the transportation industry. The Northwest has the second largest penetration of electric vehicles in the country. BPA expects load profile changes and increased energy demand with a higher penetration of electric vehicles.

- **Decentralization:** More decentralized wind and solar generators are replacing centralized coal plants near major load centers, e.g., Centralia, Washington, and in more remote locations, e.g., Colstrip, Montana and Point of Rocks, Wyoming. Residential solar is not common in the region, but utility scale wind and solar projects are, and they tend to be located in rural areas in BPA's service territory. These individual wind and solar projects are generally smaller increments than single coal units, and there are numerous projects proposed or moving forward. The transmission grid of the future will be able to serve a growing number of these smaller generators, in addition to the larger ones in a very diverse set of locations.

- **Technology:** Technology affects every part of the power industry. The faster pace of innovation in a range of areas will affect Transmission Services in different ways.

    - **Data centers:** The dramatic growth of digital products has increased the need for data centers, and the rural Northwest is one of the preferred locations. BPA expects that trend to continue.

- **Electrification:** Changing technologies for the end user, such as increased electrification of the transportation sector, will change the load curve. Other examples of the end-user electrification is the continuing shift to more digital technologies in lighting and increased use of batteries in consumer electronics.
- **Smart grid:** The development of a variety of digital technologies and tools offer Transmission Services the opportunity to improve its operations, security and customer support.
- **Solar and wind resources:** Solar and wind technologies will be the prevailing resources developed in the planning horizon. In addition, there is increased interest in developing offshore wind along the Washington and Oregon coasts.
- **Storage:** The development of utility-scale batteries is a relatively new development in the industry. Batteries are being piloted and developed for a range of applications, but there is still a lot to learn. Costs are expected to come down over time because of volume manufacturing and chemistry advances, making their use more possible in the latter part of the decade or later. Batteries will also play a central role in the advancement of distributed energy resources, demand response, grid integration and shifting energy usage.

- **Regional cooperation:** BPA cooperates with regional partners to gain efficiencies in transmission planning and operations. BPA is active in NorthernGrid, the Western Power Pool, Western Electricity Coordinating Council workgroups and other regional planning industry organizations. In 2022, BPA joined the Western Energy Imbalance Market and is currently considering other power market initiatives.

- **Regulatory Reform:** In the last few years, federal and state regulation has been more proactive in promoting decarbonization goals. At the federal level, FERC and the Department of Energy have been active in promoting regional and inter-regional planning as well as enhancing transmission planning and generation interconnection. These regulatory reforms will have a significant impact on transmission planning in the future.

Long-Term Transmission Planning conducts production cost modeling and studies system optimization models to gauge market availability of resources, predicting future trends in resource types and location, including assumed transmission needs. Transmission Planning conducts power flow analysis to define system expansion over the planning horizon to ensure BPA's transmission system can reliably deliver resources to load and meet its transmission obligations. These analyses will inform the Resource Program in the future on market availability, transmission deliverability for future resource scenarios conducted, and transmission needs for reliable delivery of resources to loads.

8.2 Loads and Resources

8.2.1 Resources

Located on the mainstream Columbia River and on several of its major tributaries (Figure 8.2), including the Snake and Willamette rivers, the Federal Columbia River Power System, or FCRPS, comprises 31 hydroelectric projects in the Columbia River Basin and provides carbon free energy that accounts for about one-third of the electricity used in the Pacific Northwest. These federal hydro projects are operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers.

Through its transmission system of more than 15,000 circuit miles of high-voltage facilities, BPA delivers and distributes the power generated from both federal and non-federal projects of all resource types such as hydro, wind, solar, etc. The revenues collected from the use of the system cover the cost of operating and maintaining the transmission facilities that comprise the Federal Columbia River Transmission System, or FCRTS.

Figure 8.2 – FCRPS Resources

BPA delivers power from both federal hydro projects and non-federal resources, i.e. solar, thermal, wind, etc., to a wide range of customers in accordance with its OATT. Transmission service is generally divided into two products: Network Transmission, or NT, and Point-to-Point, or PTP. The traditional municipalities, public utility districts and cooperatives with load-serving priorities utilize mostly NT transmission service, while a wider variety of customers, such as investor-owned utilities, independent power producers, marketers and others utilize the more flexible and marketable PTP transmission service to access a greater mix of resources for delivery to either load or market.

8.2.2 Loads

BPA will serve 139 NT customers in the planning horizon, from 2022-2032, for a total forecast of 6,018 average megawatts in 2022 and 7,488 aMW in 2032, plus 24.4% in ten years. In 2022, 36 of these customers have demand of 5 aMW or less. A few of the NT customers will experience significant growth, while others will be mostly flat, and in some cases, negative. Among the top 10, Umatilla Electric Coop, Cowlitz PUD and Northern Wasco PUD will experience significant growth, while many municipalities

remain mostly flat or even negative. The growth in the rural areas and small towns has been in large part due to data centers and industrial customers attracted to the Northwest for its low- cost power. Through the planning horizon, the forecasted NT customer peak demand will be winter peaking at 9,513 MW in 2022 and 11,311 MW in 2032.

Figure 8.3 displays projected loads for NT customers of 25 MW or greater. The load circle area is proportionally sized according to the customer load. The top five NT customers only are ranked by demand, measured in aMW, on the legend. The map includes NT and the larger PTP customers with loads of 25 aMW or more. While shown in the key, the map itself does not include PacifiCorp, delineated with an asterisk, which receives transmission service across the Northwest. The map also does not include loads smaller than 25 aMW, which aggregated to 784 aMW in 2022. Figure 8.3 also shows PTP customers, with the top five PTP customers being Puget Sound Energy, Portland General Electric, PacifiCorp, BPA Power Services and Snohomish County PUD.

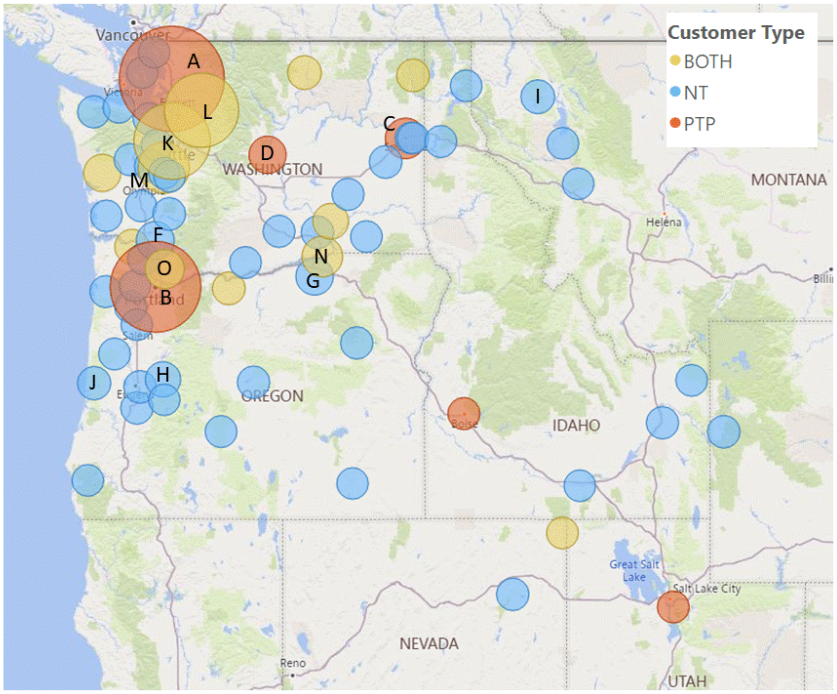
Figure 8.3 – 2022 Transmission Loads

Legend – Top 5 NT only	
F	Cowlitz County PUD
G	Umatilla Electric Coop
H	Eugene Water & Electric
I	Flathead Electric
J	Central Lincoln

Legend – Top 5 PTP only	
A	Puget Sound Energy
B	PGE
*	PacifiCorp
C	Avista
D	Alcoa

Legend – Top 5 Both PTP & NT	
K	Seattle City Light
L	Snohomish PUD
M	Tacoma Power
N	Benton PUD
O	Clark Public Utilities

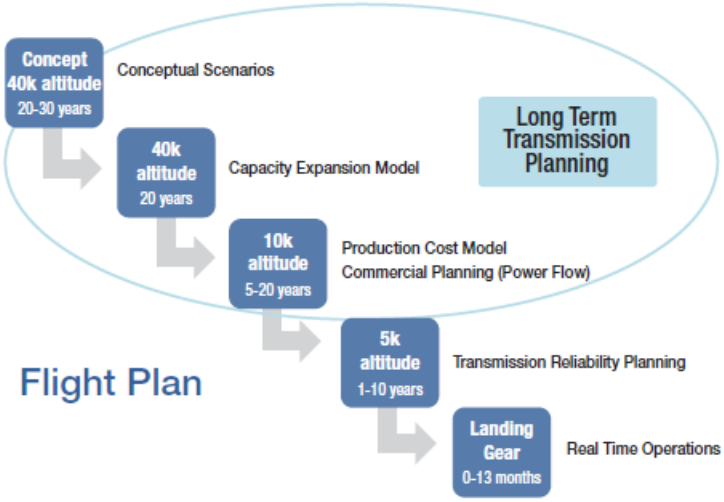
* Not shown



8.3 BPA Transmission Planning

Transmission planning is done at different levels for multiple purposes. To better understand this process, Figure 8.4, Transmission Planning Flight Plan, is a graphical representation, or overview, of the various transmission planning processes within Transmission Planning and Asset Management. These processes include transmission planning from a reliability viewpoint and long-term transmission planning from a commercial planning viewpoint.

Figure 8.4 – Transmission Planning Flight Plan



A. Transmission Reliability Planning

Every year, BPA Transmission Planning conducts a comprehensive assessment of the FCRTS to determine its ability to provide reliable service over a 10-year planning horizon. Transmission Planning studies 27 load service areas and 16 paths under defined limiting system conditions in order to identify any potential performance deficiencies. The analysis is used to identify system reinforcements needed to continue to provide reliable transmission service over the planning horizon.

The system assessment allows BPA to demonstrate that existing and forecasted load and projected firm transmission service can be reliably served through, at least, the 10-year planning horizon. It also allows BPA to show that identified corrective action plans, such as system reinforcement, are adequate for reliable performance.

The main objectives of the system assessment are to demonstrate that BPA meets the mandatory North America Electric Reliability Corporation, or NERC, TPL Standard known as Transmission System Planning Performance Requirements, reliably serve loads, and fulfills obligations to reliably deliver resources to load. The NERC standard requires that BPA conduct an annual assessment to ensure that the BPA network is adequately planned to supply projected customer demand and projected firm transmission service over the expected range of forecast system demands following a wide range of probable contingency outages.

Transmission Planning evaluates the transmission system for the near-term, one to five years, and long-term, six to ten years, planning horizons to determine whether system performance meets performance requirements of the NERC TPL Standard, WECC System Performance Regional Criterion and BPA Reliability Criteria for Transmission Planning. If the system assessment identifies any potential system performance deficiencies, corrective actions, including transmission reinforcements, are developed to address the potential system deficiencies.

Load Forecast

The Transmission Planning organizations work closely with the Load Forecasting group, using a common process to identify more efficient ways of collecting and evaluating customer-provided information. This

ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process between Transmission Services and Power Services.

The overall system assessment starts with developing technical basecases. A basecase is a database used by the power flow software program to model the loads, topology and generation. Then, contingency outages as required by the NERC TPL Standard are studied using the basecases to assess required system performance. Assumptions are made in the system assessment basecases for load forecasts, resource forecasts and transmission service. The basecases start from WECC-approved basecases. These include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecast used by Power Services for the power Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. If necessary, the load forecasts are then updated with the most up-to-date load forecast data available from the other utilities.

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process.

Resource Forecast

Resource forecasts for the system assessment include existing and committed future resources that are expected or forecasted to operate as determined in coordination with Power Services. Specific generation patterns are assessed that are expected to create higher transmission system stress consistent with historical usage to determine the limits of the transmission system.

Existing Obligations and Committed Long-Term Firm Transmission Service

In addition to load and resource forecasts, the system assessment includes existing transmission service obligations and committed long-term firm transmission services. These transmission service obligations and commitments are identified during transmission expansion planning by BPA Long-Term Transmission Planning. System assessments conducted by Transmission Planning capture these transmission service obligations and commitments through path flows resulting from the load forecast and the generation patterns that are assessed.

Non-Wires

BPA Transmission Planning, in collaboration with the BPA Cross-Agency Non-Wires team, considers the feasibility of non-wires solutions as alternatives to or as deferrals of transmission reinforcement projects. The range of non-wires solutions that are considered include demand-side management, which includes energy efficiency and demand response, distributed energy resources such as energy storage and distributed generation, and generation re-dispatch. BPA Transmission Planning conducts a non-wires assessment to identify feasible candidates, following its annual system assessment. Non-wires alternatives to reliability projects are considered where feasible. For areas that have performance deficiencies and corrective action plans identified within the planning horizon, the potential for non-wires alternatives is identified to either correct the deficiency or defer the date when a project is required to comply with the NERC Standards. Following the system assessment, Transmission Planning summarizes the areas with the potential for non-wires projects. In collaboration with the Cross Agency

Non-Wires team, areas are prioritized, and a recommendation is made regarding which area justifies further analysis by the team.

Coordination Between Power Services and Transmission Services

Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups to achieve efficient data collection, an analytical evaluation and optimal recommendations. Specifically, BPA coordinates between Transmission Planning, Long-Term Transmission Planning and Long-Term Power Planning in their planning activities, processes and decision-making in a way that enables the agency to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers.

- Transmission Planning coordinates input resource assumptions for system assessment basecases with Long-Term Power Planning and Long-Term Transmission Planning. This includes ensuring that the peak period generator capacities are reasonable and properly allocated for all generating plants. Transmission Planning also collaborates on information regarding generation retirements.
- Transmission Planning coordinates long duration generator outage assumptions for basecases with federal hydro projects to include in the system assessment studies.
- System assessments and the Resource Plan start from common agency load forecasting information for BPA customers. Transmission Planning and Long-Term Power Planning coordinate with Load Forecasting and Analysis to gain a common understanding of the load forecast process, methodology and outputs.
- When the system assessment is completed, results and corrective action plans are coordinated with Power Services and Transmission Long-Term Transmission Planning to collaborate on possible integrated solutions between Transmission and Power.
- Non-wires potential, prioritization, and analysis are done in collaboration between Transmission Services and Power Services.

B. Commercial Planning

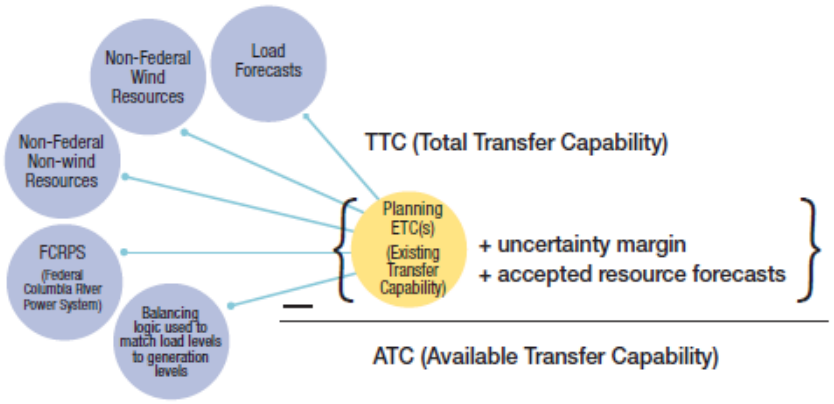
Long-Term Transmission Planning is responsible for the Transmission Service Expansion Planning for future transmission service requests, a process that starts with calculating the available transfer capacity, or ATC, for each transmission flowgate. The capacity then becomes eligible to meet the needs of BPA customers who submit transmission service requests, requesting capacity for their loads and resources. These TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements necessary to serve the TSR needs. Customers are informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction. More on how this process works follows.

Long-Term Available Transfer Capability

On an annual cycle, BPA Long-Term Transmission Planning uses a power-flow based model to calculate Existing Transmission Commitments on BPA's monitored Network Flowgates under various system conditions and seasons. Using the calculated ETCs and the total transfer capability, the algorithm ATCFirm = TTC– ETCFirm informs the available transfer capability inventory across Network Flowgates for the long-term market. The annual LT ATC update allows BPA Transmission

Services to manage long-term firm transmission sales as well as inform the cluster study. Refer to Figure 8.5 below for a graphical representation.

Figure 8.5 – Inputs to Long-Term ATC Calculations for Network Flowgates



To calculate long-term ATC, Long-Term Transmission Planning engineers utilize five- and 10-year- out basecases for winter and summer, which originates from WECC-approved basecases. These winter and summer basecases represent a normal one-in-two non-coincidental peak load forecast. The basecases include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecasts used by BPA Power Services for their Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. The load forecasts are then updated with the most up-to-date load forecast data available from the other utilities. A light spring basecase is derived from a summer peak basecase by reducing loads and adjusting generation patterns appropriately to reflect historical spring hydro conditions.

Resource forecasts for the FCRPS are provided by Power Services. The resource forecasts take into account forecasted FCRPS generator outages for the season. The FCRPS is modeled with three dispatches that separately stress the hydro system at the upper Columbia, lower Columbia and lower Snake projects.

Non-federal wind resources identified in PTP and NT contracts are modeled in "off" and "on" scenarios. In the "on" scenarios, PTP wind is modeled at the contract demand and capped by its nameplate, and NT wind is modeled at the designated MW level for the generator. In the "off" scenarios, PTP wind is replaced with FCRPS generation using a balancing logic method. Non-federal non-wind resources are modeled at contract demand, capped at the lower of the nameplate or historical peaks/seasonal capability.

Transmission Service Request Study and Expansion Process

Every year, Transmission Planning conducts a Transmission Service and Expansion Process, or TSEP, to analyze requests for new long-term firm transmission service. This includes a needs assessment to identify capacity deficiencies across the transmission system for future requests, and a cluster study to identify system reinforcements to provide the requested capacity. A benefit of using the TSEP is that Transmission Services can study transmission requests in aggregate, to identify "right-sized" transmission solutions to meet the demand. In addition, multiple customers then have the opportunity to participate in cost sharing of any needed transmission infrastructure, resulting in lower cost to individual customers and higher project subscription levels.

As part of the TSEP, BPA Long-Term Transmission Planning conducts a needs assessment to identify capacity needs across the transmission system in response to long-term firm TSRs, which feeds into the cluster study process. The needs assessment starts with developing a robust range of plausible scenarios that would adequately capture anticipated utilization of BPA's Network Flowgates. These scenarios consider similarly situated resources, expected resource type, and market and weather conditions in the scenario development. The needs assessment also utilizes data from production cost modeling to inform an estimated economic merit order dispatch in the scenarios, as well as new plausible scenarios of predicted congestion.

The scenario basecases used for the needs assessment are power flow models that are derived from five-year-out long-term ATC basecases for the winter, spring and summer seasons. Since the starting LT ATC basecases already include load forecasts, resource forecasts and existing transmission service commitments, the derivative scenario cases include modeling of the long-term firm transmission service requests in BPA's Long-Term Pending Queue as well as accepted NT load growth forecasts from the NT dialogue. Analysis of the set of scenario basecases determines which flowgates are deficient in capacity and the amount of capacity needed to accommodate requested future transmission service.

For those transmission paths where capacity deficiencies are identified, Transmission Planning conducts cluster studies to identify the system reinforcements needed to provide the required capacity both across the transmission paths and within local areas where associated resources are located.

Once Transmission Planning completes the cluster study and provides the results and defined transmission reinforcements, study participants decide whether to continue pursuing the requested transmission service. After the study participants have made decisions whether to support the identified transmission reinforcements, Transmission Services then initiates the next year's cluster study cycle to respond to new transmission requests submitted since the beginning of the previous study. This cyclical study process enables Transmission Services to efficiently and timely meet customer needs and satisfy its tariff obligations.

An area of recent interest for Transmission Services is the assessment of battery storage to potentially meet commercial planning needs. The exploration addresses technology improvements, increasing cost reductions in energy storage and the role of energy storage in the commercial planning space. Long-Term Transmission Planning is developing a framework to evaluate potential battery use cases, ownership models, impacts to BPA policies and an overall cost structure.

C. Long-Term Capacity Expansion

Long-Term Transmission Planning utilizes the Long-Term Capacity Expansion, or LTCE, tool to co-optimize resource and transmission capacity expansions over a long-term, 20-to-30-year horizon. The tool identifies future resource capacity and energy deficits in the various sub-regions of the Northwest and computes an optimal mix of both transmission and resource capacity additions.

The initial model is populated with at least 20 years of load, resource and transmission data at a zonal level of granularity for the Western Interconnection. Inputs in refining this base data are extracted from a variety of sources such as BPA's Transmission Planning, Load Forecasting and Analysis, and Long-Term Power Planning groups; the Northwest Power and Conservation Council; WECC; and the Northwest Power Pool.

Long-Term Transmission Planning is utilizing LTCE with the intent to evaluate several major trends in the external market landscape that affect transmission. The model has the capability to address how state carbon policies can influence the timing of transmission needs and performance in the Pacific Northwest. It can also assess how a combination of energy storage, variable energy resources and hydro perform with respect to adequacy.

D. Production Cost Model

Long-Term Transmission Planning simulates security constrained economic dispatch and unit commitment with the GridView software in order to quantify how uncertainties, such as load growth and public policy requirements, will affect transmission congestion and utilization. Scenario analysis best practices are used to identify "least regrets" transmission reinforcements.

Long-Term Transmission Planning supplements the WECC Anchor Data Set with additional data from BPA load forecasters, power planners and transmission planners. The transmission system is modeled at a nodal level of granularity with constraints approximated by path and flowgate transfer limits.

E. Intra-agency Coordination

There are several other examples of coordination between Transmission Services and Power Services for large and small projects in addition to those discussed above. One significant effort in the recent past is the Columbia River System Operations Environmental Impact Statement. For the CRSO EIS, the analytical process between the two organizations followed six steps over the course of two years. The process included linkage of changes in how and where power is generated to effects on the transmission system reliability and congestion.

Another example of coordination between Power Services and Transmission Services is the cross-agency Southeast Idaho Load Service initiative focused on how to best serve six preference customers in southeast Idaho that have long-term power and transmission contracts with BPA. This included commercial negotiations related to the Boardman – Hemingway transmission project, as well as resource acquisition and transmission service options.

There is also coordination between Transmission Services and Power Services reviewing impacts of river operations on the transmission system. This includes analyzing minimum generation levels on the lower Columbia River to maintain system reliability and to determine if other significant changes to generation patterns are expected.

Section 9: Glossary of Terms

18-Hour Capacity – Metric used for evaluating capacity surplus/deficit over the six peak load hours per day during a simulated three-day extreme weather event, such as a cold snap or heat wave, and assuming median water conditions.
Available transfer capacity – Also "available transfer capability." Measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Balancing authority – Synonym for load control area agency. The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.
Balancing authority area – The collection of generation, transmission and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.
Balancing reserves – Incremental and decremental generation flexibility or demand response that is connected to BPA's Automatic Generation Control system and is capable of responding to signals requesting Regulation Service and Within-hour Following Service in proportion to the AGC signal requirements.
Behind-the-meter generation – Energy generated on-site and on the consumer side of the meter facility, such as residential solar.
Canadian Entitlement – The Canadian Entitlement is one-half of a treaty formula that measures the increase in usable energy and dependable capacity for an imaginary 1960-level hydrothermal power system with procedures designed to provide acceptable cost/benefits during the life of the treaty.
Capacity – Capacity is defined and measured in various ways. BPA measures the capacity of its system by determining its maximum output in its 18-hour capacity studies, which represent the most stressful type of event BPA's power system could expect to experience approximately once in every 10 years.
Conservation Potential Assessment – Study conducted to assess the amount and costs of energy efficiency measures available from BPA's forecasted customer loads over the planning horizon.
Critical water – The second-lowest historical streamflows on record used to model the amount of power the regional hydropower system could produce, given today's generating facilities and constraints.
Cut plane – Group of transmission lines.
Decarbonization – Reducing the carbon content of all transformed energies such as electricity, heat, liquids and gases. In the power sector, this means replacing coal, as well as gas and oil, with renewable energy.
Decentralization – Energy generated off the main grid and produced near to where it will be used, rather than at a large plant elsewhere and sent through the grid.
Demand response – Programs intended to reduce the use of electricity during times of peak demand.
Demand-side resources – Load management programs, such as energy efficiency, implemented by utilities. These resources can also include demand response, load shifting measures, and Behind-the-meter generation and storage.
Distributed energy resources – Systems such as small-scale power generation or storage technologies – typically in the range of 1-10,000 kilowatts – used to provide an alternative to or an enhancement of the traditional electric power system.
Efficient frontier – Result from the Resource Program analysis that produces the least-cost combination of available resources that meets the given constrains. It also identifies various other combinations of resources that minimize portfolio variance for a given cost point.

Energy – The amount of electricity demanded, produced or required, over a specific period of time, sometimes measured in annual average megawatts, aMW, or in megawatt hours, MWh.
Energy efficiency – Using less energy to perform the same function or service.
Federal Energy Regulatory Commission (FERC) – An independent government agency delegated by Congress with the authority to regulate the energy infrastructure of the United States, including the transmission of electricity.
Flowgate – 1) Individual or group of transmission facilities, i.e., transmission lines, transformers, known or anticipated to be limiting elements in providing transmission service; or 2) designated point(s) on the transmission system through which the Interchange Distribution Calculator calculates the power flow from interchange transactions.
Heavy load hours – Times of highest electricity usage; for BPA, heavy load hours are hours ending at 7 a.m. to 10 p.m., Monday through Saturday, excluding North American Electric Reliability Corporation holidays.
Hub – Combination of the electrical grid and other networks, such as natural gas pipelines, for the production, conversion, storage and consumption of different energy generators.
Independent power producer – A non-utility producer of electricity that operates one or more generation plants under the 1978 Public Utility Regulatory Policies Act, PURPA. Many independent power producers are co-generators who produce power for their own use and sell the extra power to their local utilities.
Integrated Resource Plan – A long-term resource planning process conducted to help ensure a utility meets its expected future obligations at low cost and with minimum practical risk.
Intertie – A system of transmission lines permitting a flow of energy between major power systems. The BPA transmission grid has interties to British Columbia, California and eastern Montana.
Investor-owned utility – A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders; a private utility.
Light load hours – Generally, times of low electricity usage; for BPA, light load hours are hours ending 11 p.m. to 6 a.m., Monday through Saturday, all day Sunday and holidays as designated in the North American Electric Reliability Corporation Standards.
Load – The amount of electric energy delivered or required at any specified point or points on a system.
Market depth limit – Result of a study used to determine how much energy BPA could reliably purchase from the wholesale market.
Market transformation savings – Associated with the Northwest Energy Efficiency Alliance's programs and initiatives that focus on long-term market change and push the region toward more efficient technologies.
Momentum savings – BPA tracks and reports momentum savings for select markets. Momentum savings are defined as all the energy efficiency occurring above the Northwest Power and Conservation Council's plan baseline that are not directly reported by utilities and not part of the Northwest Energy Efficiency Alliance's market transformation savings.
Network transmission – Transmission contract or service described in a transmission provider's Open Access Transmission Tariff, OATT.
North American Electric Reliability Corporation (NERC) – A not-for-profit international regulatory authority appointed by the Federal Energy Regulatory Commission whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
Northwest Energy Efficiency Alliance (NEAA) – A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.
Open Access Transmission Tariff – Tariff for use of high-voltage transmission lines required by FERC under its Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers; terms and conditions by which BPA provides nondiscriminatory transmission service

that is similar to the Federal Energy Regulatory Commission's pro forma tariff mandated for FERC jurisdictional utilities.

Outage – In a power system, an either scheduled or unexpected period during which the transmission of power stops or a particular power-producing facility ceases to provide generation.

P10 – The 10th percentile of a distribution.

P10 heavy load hour – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over heavy load hours by month, given variability in hydropower generation, load obligations and Columbia Generating Station output amounts.

P10 Super-Peak – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations and Columbia Generating Station output.

Peak load – The highest amount of one-hour load on the entire system in a stated period of time. It may be the maximum load at a given instant in the stated period or the maximum average load within a designated interval of the stated period of time.

Peak runoff – The period of time during which the maximum volume of precipitation, snowmelt or irrigation water that runs off the land into streams or other surface water within a watershed or basin. BPA forecasts the amount of water expected to enter the Federal Columbia River Power System based on winter snowpack measurements and historical volumes.

Point-to-point transmission – Reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery, including any ancillary services provided by the transmission provider in conjunction with such service.

Ramp rates – 1) The amount of conservation or demand response that a program can acquire annually; 2) The rate at which the power output of a generator or generating project can be increased or decreased.

Redispatch – Management of generation patterns to overcome cut plane or outage problems.

Resource portfolio/stack – A set of resources, such as nuclear, natural gas, wind, solar and/or hydropower, used to provide power products. Demand side resources such as conservation, storage, rooftop PV, and demand response can also be in a resource portfolio.

Spill – Water that goes over the spillway of a dam rather than through its turbines, meaning it is not used to generate electricity.

Supply-side – Generating resources or activities on the utility's side of the customer's meter used to supply electric power products or services to customers, rather than meeting load through energy-efficiency/conservation measures or on-site generation on the customer's side of the meter.

Western Interconnection – Synchronously operated interconnected electric transmission systems located in the Western United States, Baja California, Mexico, and Alberta and British Columbia, Canada.

Western Electricity Coordinating Council (WECC) – An independent, non-profit organization delegated by NERC and FERC to promote the reliability of the power system in the geographic area known as the Western Interconnection.

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BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621, Portland, Oregon 97208-3621
DOE/BP-5201 • October 2022

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-144:
Power Council 2024 Resource Program Results

Jeffery C. Allen
Chair
Idaho

Ed Schriever
Idaho

Doug Grob
Montana

Mike Milburn
Montana

Northwest **Power** and **Conservation** Council

KC Golden
Vice Chair
Washington

Thomas L (Les) Purce
Washington

Ginny Burdick
Oregon

Louie Pitt, Jr.
Oregon

January 7, 2025

MEMORANDUM

TO: **Council Members**

FROM: **Jennifer Light, Director of Power Planning**

SUBJECT: **Bonneville's 2024 Resource Program Results**

BACKGROUND:

Presenters: Suzanne Cooper, Senior Vice President of Power Services
Ryan Egerdahl, Manager of Long Term Power Planning
Allie Mace, Manager of Market Analysis and Policy
Eric Federovitch, Manager of Long Term Power Sales and Purchase

Summary: Bonneville has finalized its 2024 Resource Program (also known as RP-24). Bonneville's resource program is an analysis of potential system needs and resources available to meet those needs. Bonneville staff will join the Council to share the results from the 2024 Resource Program and early thinking on preparations for its next resource program, which is planned to be completed in September 2026.

Relevance: The Resource Program is informational and not a decision-making process, nor a decision document, but the results do inform Bonneville's resource acquisition strategies. For the past several years, Bonneville has been working with its customers and the region on new contracts for the post-2028 period. These conversations have highlighted that Bonneville may need to acquire additional resources to serve its obligations under these new contracts. Bonneville has stated that the 2024 Resource Program is expected to provide insights to

customers on potential resource types that Bonneville might pursue to serve that obligation.

When acquiring new resources, Bonneville is required to act consistent with the Council's power plan. Therefore, it is critical for the Council to understand the results of the current resource program, and how the results align with the Council's current power plan (the 2021 Power Plan).

It is also worth keeping in mind that Bonneville is starting to work on its 2026 Resource Program (RP-26), which it plans to complete by September 2026. The timing of this next resource program overlaps significantly with the Council's planned development of its Ninth Power Plan.

Background: Bonneville recently completed its 2024 Resource Program and presented the results in a public workshop on December 19th, 2024. Bonneville has stated publicly that this resource program is expected to provide insights to customers around the types of resources it might acquire should it need to acquire new resources to meet its future obligations.

The 2024 Resource Program includes results for a base scenario along with several sensitivities, including sensitivities that look at market prices, market reliance, and load growth. Bonneville also conducted a specific study exploring potential resources for Tier 1 augmentation.[1] Bonneville will walk through the findings of this analysis at the January Council meeting.

The Council's current power plan, the 2021 Power Plan, provides specific recommendations to Bonneville, which include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041
- Work to enable and encourage its customer utilities to pursue low-cost and high value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified.

[1] Under the Bonneville Provide of Choice Policy, which is guiding its post-2028 contract development, Bonneville has agreed to sell 7250 aMW of power at a Tier 1 rate. Based on the existing system capability, Bonneville may need to acquire additional resources to meld into the existing Federal Base System in order to meet that obligation. This study focused specifically on the question of which resources would be least-cost to meet that obligation.

It is worth noting that Bonneville's near-term results across all sensitivities (i.e. pre-2030 builds) and its Tier 1 augmentation study are consistent with the 2021 Power Plan recommendations. Staff recommend the Council focus more on these near-term results, given the Council is working to complete its next power plan by the end of 2026 and Bonneville will have an updated resource program in a similar timeframe.

While the near-term results make sense, and are consistent with the Council's power plan, staff does have some questions regarding the longer-term results. Staff shared these concerns with Bonneville at the December 19th public workshop. They include:

Modeling of Emerging Resources: Bonneville included one emerging resource option, small modular reactors (SMRs), in RP-24. Council staff recommend Bonneville consider more emerging resource options in RP-26. Since different emerging resources have different attributes, analyzing more options will provide better information to Bonneville on the types of resources needed for the long-term. For reference, Council staff are planning three emerging resource options for the next plan. Council staff also recommend Bonneville rethink some of the SMR specific assumptions, particularly around online date and lifetime. Bonneville assumed the SMR was available in the model as soon as 2030. The Council understands the online date for SMRs would be 2035 at the earliest based on statements from Energy Northwest staff. The timing of emerging resource availability may change resource decisions across the planning horizon. The Council plans to explore different online dates for emerging resources in its scenario modeling to understand the implications of this uncertainty. Additionally, Bonneville assumed a 60-year life for the SMR. The assumed lifetime can significantly change the economics of a resource, with a longer lifetime making a resource look cheaper in the modeling. In the 2021 Power Plan, the Council used a 40-year life, and utilities across the region have used a range of assumptions from 30-years to 60-years. Council staff are still working with its advisory committees on the best assumptions for the upcoming plan.

Improved Understanding of Modeling Approach: Bonneville developed a new approach to its resource optimization modeling for RP-24. The newly developed optimizer provided a good step forward for Bonneville over the previous approach. Council staff are interested in better understanding the model, particularly as some of Bonneville's results are counter intuitive. As we have found with our own model development, there is significant value in opening up the models to experts in the region. The rapidly changing power system requires new modeling approaches, which the whole region is struggling to resolve. Having the opportunity to dive deeper will increase understanding and ultimately improve the modeling for all parties.

Council staff intend to work closely with Bonneville on the development of the Ninth Power Plan and Bonneville's next Resource Program.

More Info: Materials related to Bonneville's Resource Program development are available on its website: https://www.bpa.gov/energy-and-services/power/resource-planning.

BPA 2024 Resource Program & Next Steps

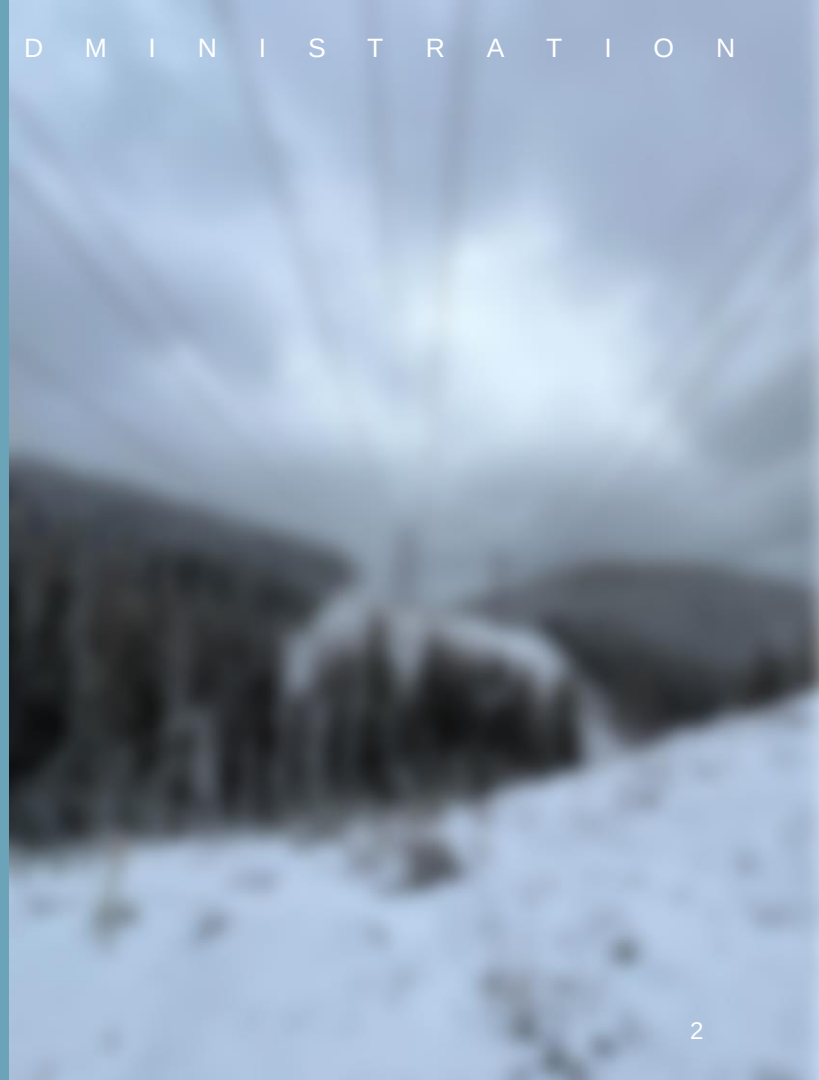
Presented to the Northwest Power and Conservation Council

January 14th, 2025

Introductory Remarks

Suzanne Cooper

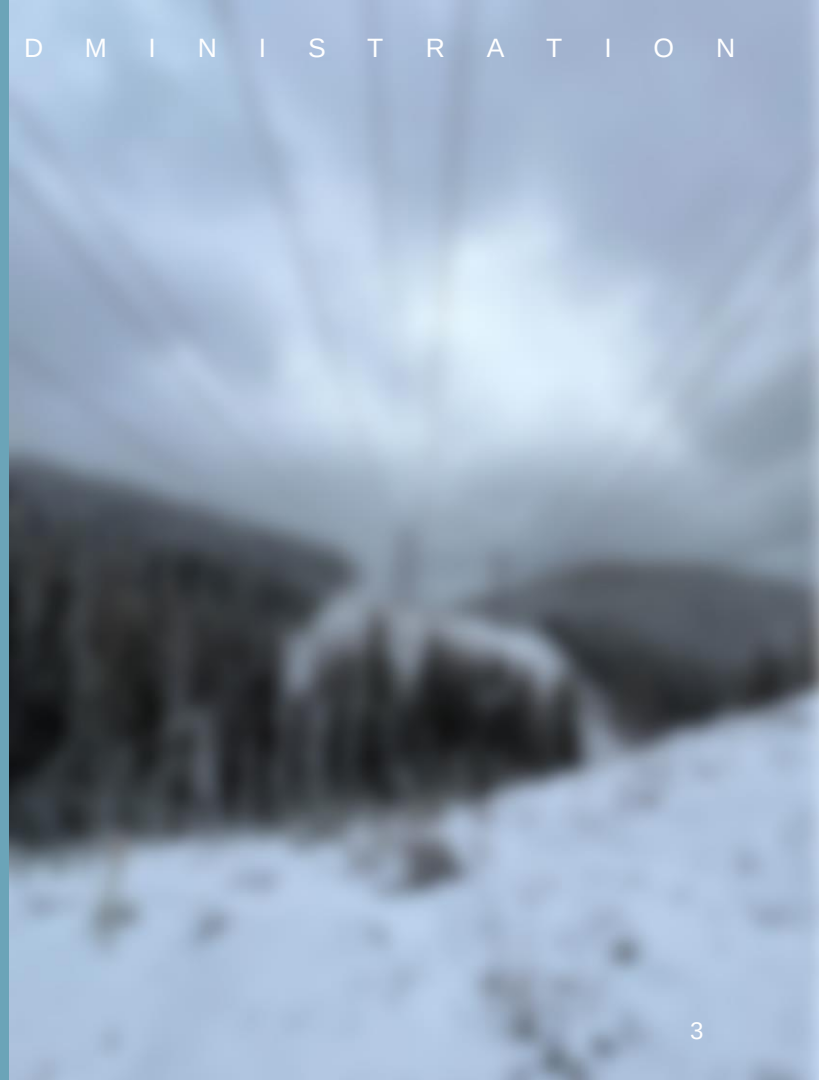
Senior VP, BPA Power Services



Resource Program Process Update and Next Steps

Ryan Egerdahl

Manager, Long Term Power Planning



Agenda

- Resource Program Process Update and Next Steps
- RP24 Resource Solutions
- Power Services Resource Acquisition Process

Reminder: Power Planning at BPA

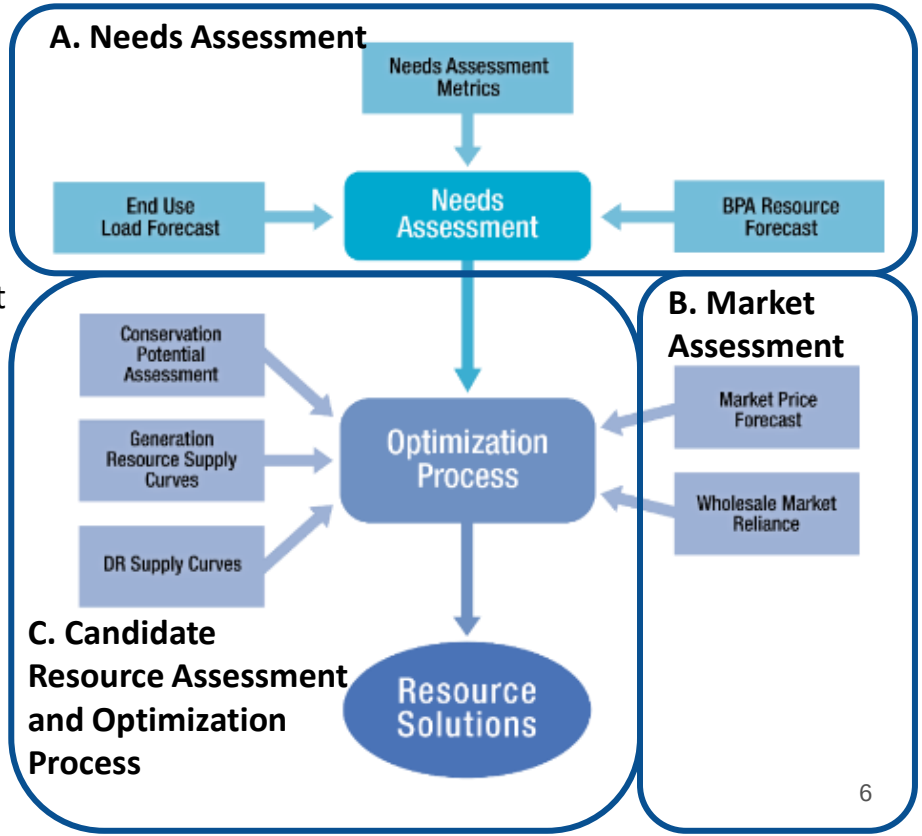
- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and describes expected energy and capacity surplus/deficits under varying water conditions.
- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to develop least-cost portfolios of resources that meet BPA's obligations.
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

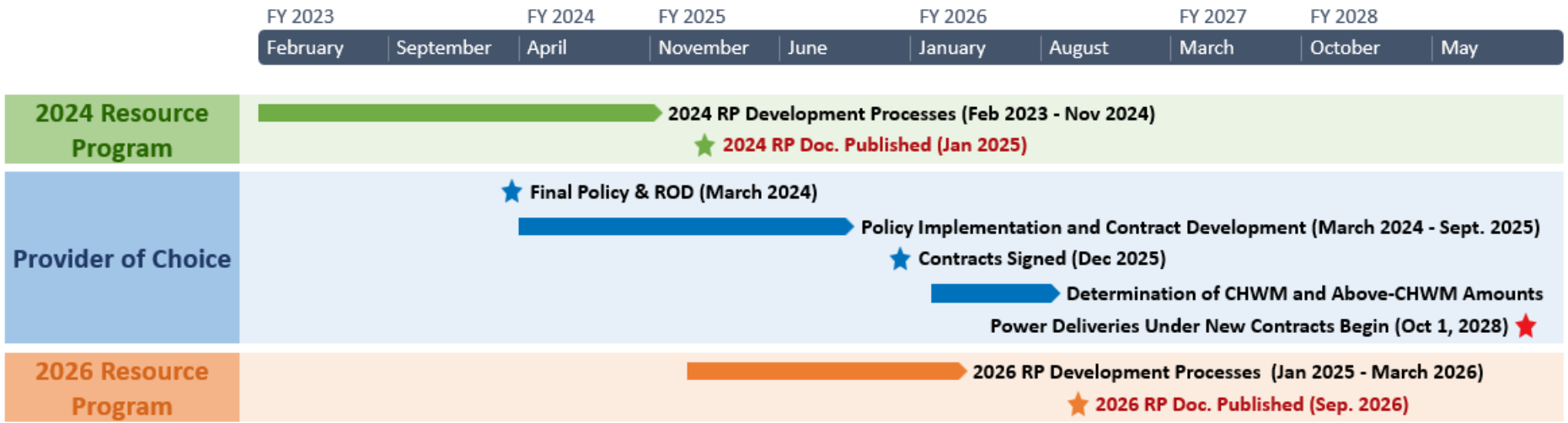
A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations

B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions

C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs



Resource Program and Provider of Choice



Possible Enhancements for RP26

- Based on feedback to RP24, BPA will consider exploring a range of modeling enhancements for RP26, including but not limited to:
  - Assess capacity metric under extreme weather and low water
  - Reintroduce balancing reserves study to Needs Assessment
  - Connect resource solutions to WRAP forward showing position
  - Include additional candidate resource options
  - Refine and refresh characteristics for candidate resources, including performance of renewables
  - Enhance linkages between resource solutions, market assessment, and needs assessment modeling
- We will also solicit additional feedback from stakeholders as RP26 planning gets underway

Next Steps and Additional Information

Next Steps:

- Publication of 2024 Resource Program expected in January 2025
- Release of BPA and Energy Northwest joint CGS EPU business case and RP24 addendum study expected spring 2025
- 2026 Resource Program to kick off in winter 2025; publication expected September 2026

Resource Program Contacts:

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Find Us:

Email: ResourceProgram@bpa.gov
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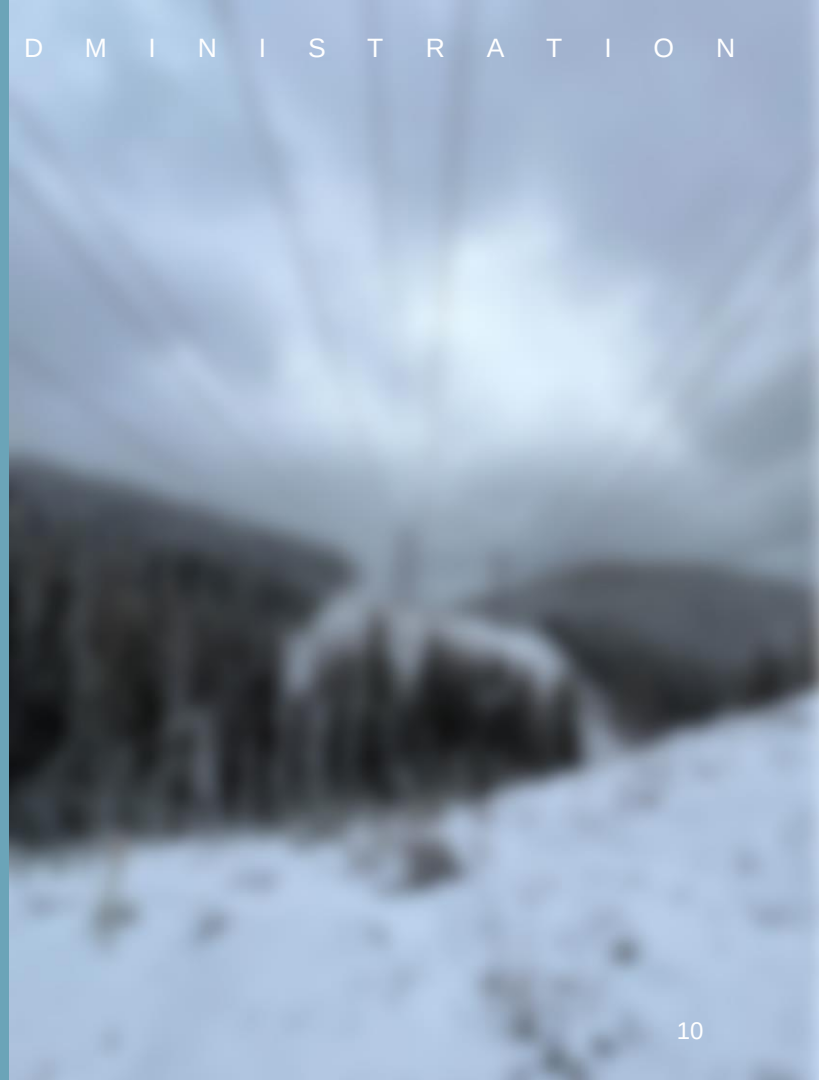
Resource Solutions

Allie Mace

Manager, Market Analysis and Policy



Key Takeaways – Resource Solutions

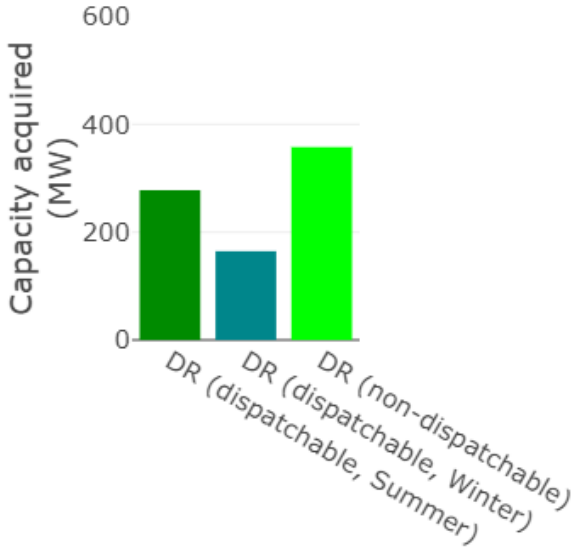
- We continue to rely heavily on **energy efficiency, demand response, and market purchases** to meet BPA needs.
- As loads grow or we add further limits on access to the market, resource acquisitions grow quickly.
- Acquisitions are driven primarily by **Flat** and **HLH energy needs**, rarely by super-peak or 18-hour capacity needs. There is not a single binding metric.
- Supply side acquisitions tend to focus on **solar** and **wind** resources due to their low costs and their contributions to energy needs.
- Supply side acquisitions in SWEDE are needed only if loads are higher than in the base scenario.
- **Resources in the model cannot meet needs in 2 sensitivities**: no market and high load. Shortfalls are in **winter/April 2026-2028**.

Base scenario: Key takeaways

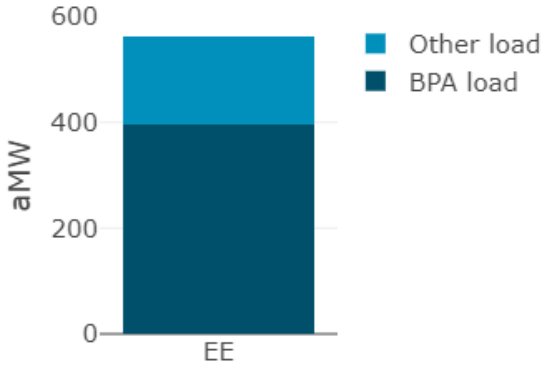
- P10 needs are met primarily by market purchases and energy efficiency (EE)
- Lowest-cost portfolio also includes several demand response (DR) programs and 300 MW solar power

Base scenario resource acquisitions

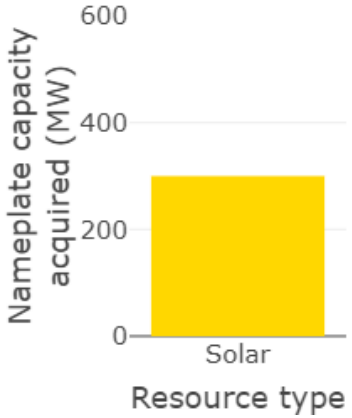
Demand response (DR):



Energy efficiency (EE):



Supply-side:



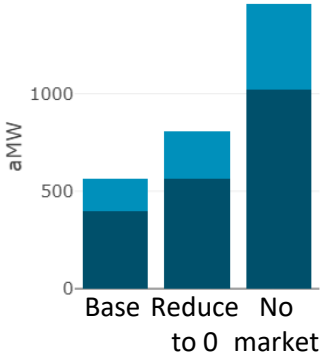
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Market limit sensitivities

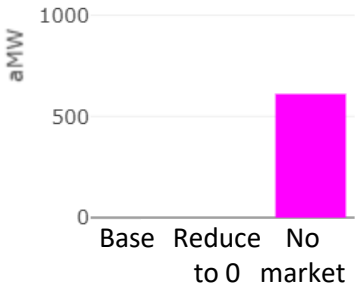
- **Reduce SPK/HLH by 25%:** Limits to SPK and HLH purchases are 75% of forecast market depth
- **Reduce SPK/HLH by 50%**
- **Reduce all market purchases by 50%**
- Reduce to 0: Limits start at 50% of forecast market depth and decline to 0
- **No market**: No market purchases allowed

Market limits: resource acquisitions

Energy efficiency:



Unmet needs:



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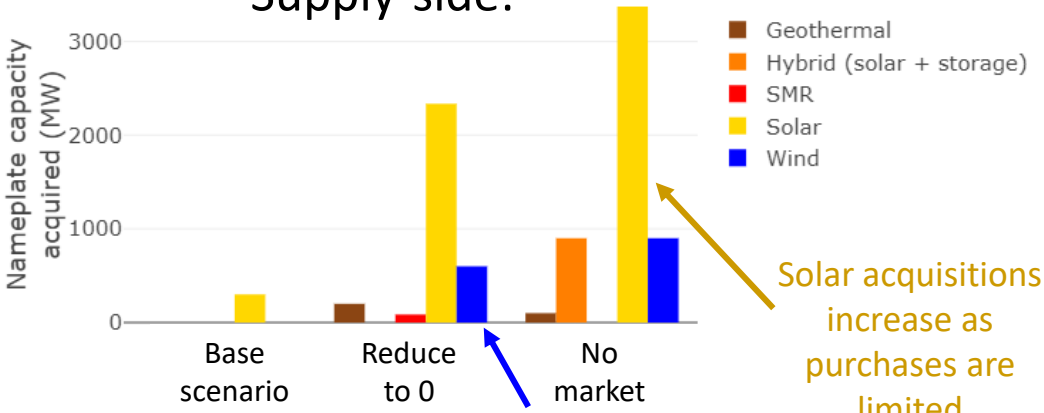
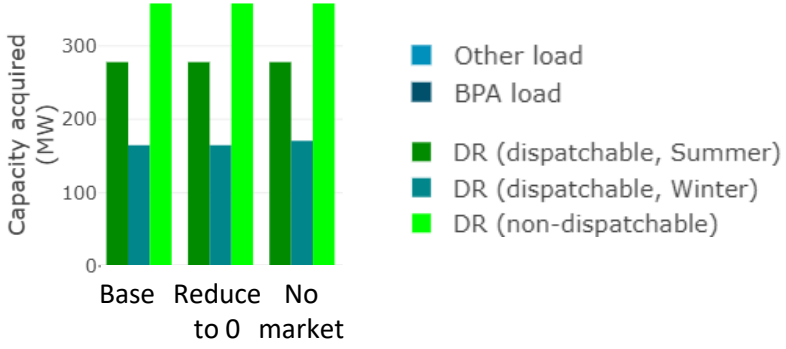


Solar acquisitions increase as purchases are limited

Wind acquisitions are present whenever LLH purchases are limited

Demand response:

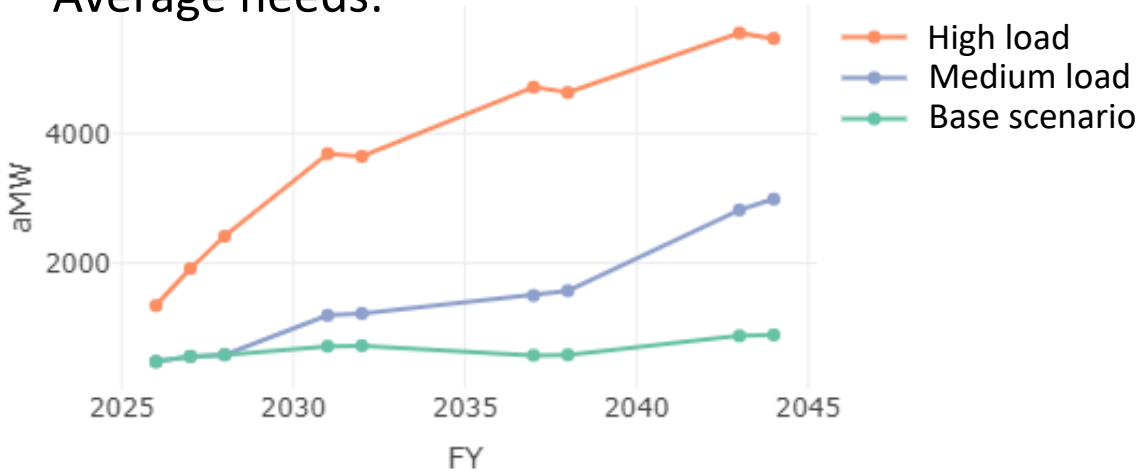


All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Load adder sensitivities

- **High load adder (aka, NR)** is a flat block load added to every hour uniformly across the year.
- **Medium load adder (aka, T2)** is shaped load added to each hour. Shaping is based on current Slice Block load shape.

Average needs:

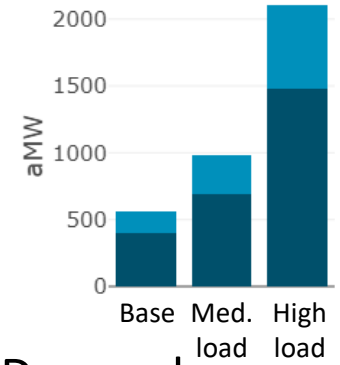


Load adder sensitivities: Key takeaways

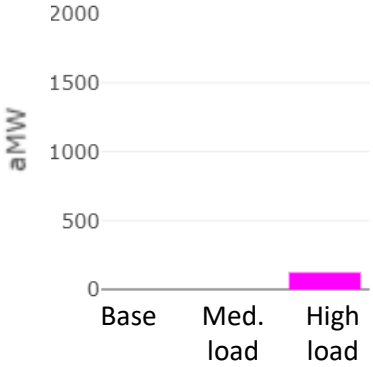
- Acquisitions are primarily driven by HLH energy needs
- Loads in the high load adder sensitivity are difficult to serve:
  - We do not have enough resources in the model to meet needs in 2026-2028 (but the shortfall is relatively small)
  - Portfolio cost is > $35 billion
- Solutions to both sensitivities include large (1,000+ MW) acquisitions of SMR
- Most acquisitions in the medium load adder sensitivity happen late, in 2043

Load adder sensitivities: resource acquisitions

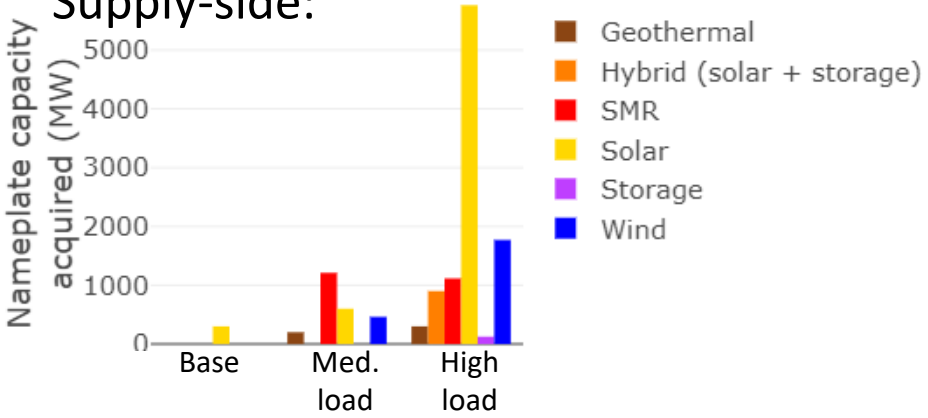
Energy efficiency:



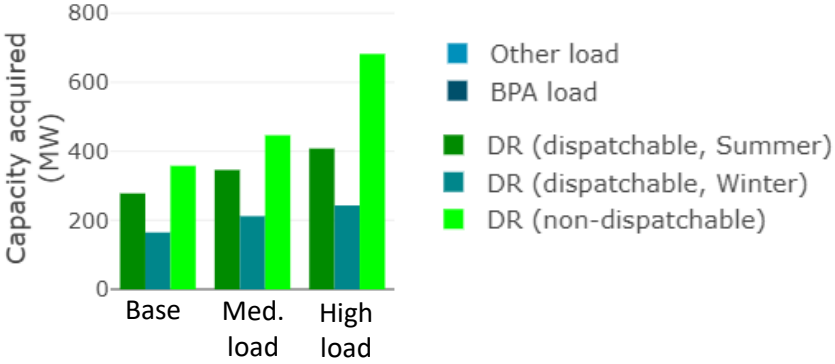
Unmet needs:



Supply-side:



Demand response:



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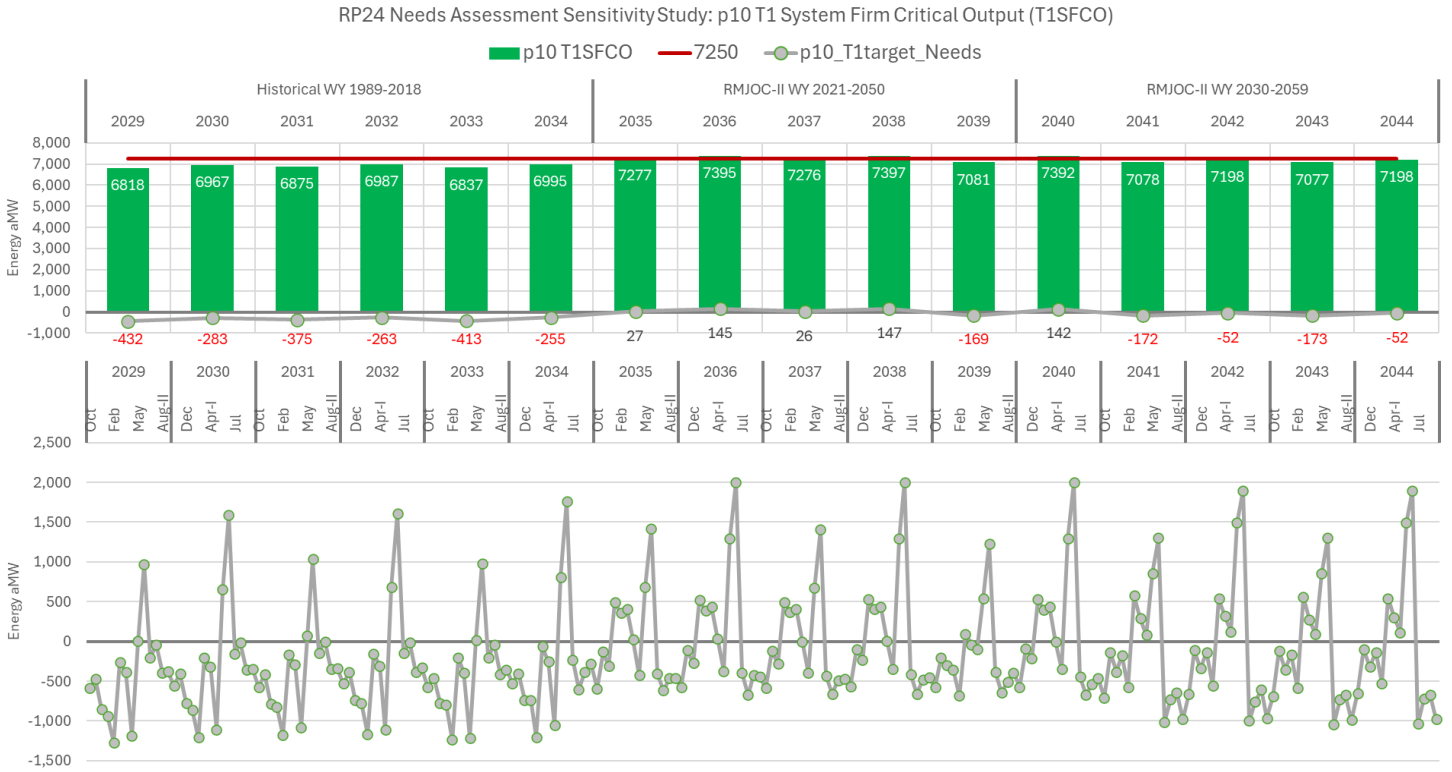
Tier 1 augmentation

- This sensitivity grows the T1 System Firm Critical Output (T1SFCO) to **7250 annual aMW** shaped to reflect **forecasted hourly shape of T1 obligations**, starting in **2029**
- Needs are modeled as average monthly energy needs at the **whole-system level** (no distinction between SWEDE and Mid-C zones)
- **Only supply-side resources** are allowed to contribute to the growth in T1SFCO
- **Current results are preliminary**: **CGS uprate** is not yet in the model. We expect to repeat this analysis when those inputs become available.

T1SFCO vs Target Augmentation

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon



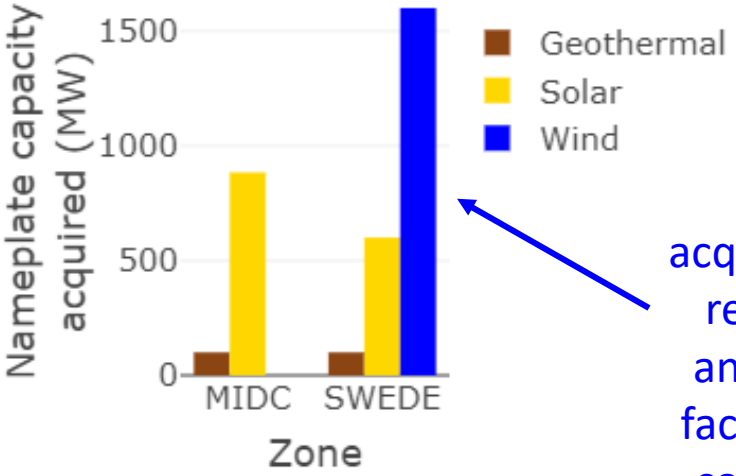
Tier 1 augmentation – Key takeaways

- Meeting T1 load exclusively with supply-side resources requires very substantial acquisitions:
  - P10 needs in the tightest month drive acquisitions
  - Generation greatly exceeds needs most of the time
- Augmentation is achieved with wind, solar, and geothermal power
- In the least-cost portfolio, most energy is generated in the SWEDE region

T1 augmentation: Resource acquisitions

We did not allow EE, DR, or market purchases to contribute to the T1 augmentation

Supply-side:



Large wind acquisitions in SWEDE reflect lower costs and higher capacity factors in that region compared to Mid-C

All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity.

Natural Gas Assessment

- Consistent with the previous resource program, we are not including natural gas (NG) resources as options directly in the solver.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. This would significantly expand the scope of the resource program modeling as multiple approaches would be needed for each scenario and sensitivity.
- Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model.
  - Incorporation of NG price risk modeling, this model has caused significant delays and errors in other applications
  - Uncertainty around costs and availability of firm fuel
  - Uncertainty around costs and key characteristics of transitioning NG resources to clean fuels (H2 / biofuels)
- The exclusion of NG resources from the solver does not preclude BPA from acquiring any resource necessary to meet needs at the lowest cost / in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.

- We will gather feedback on NG modeling for RP26 and determine direction for future modeling.

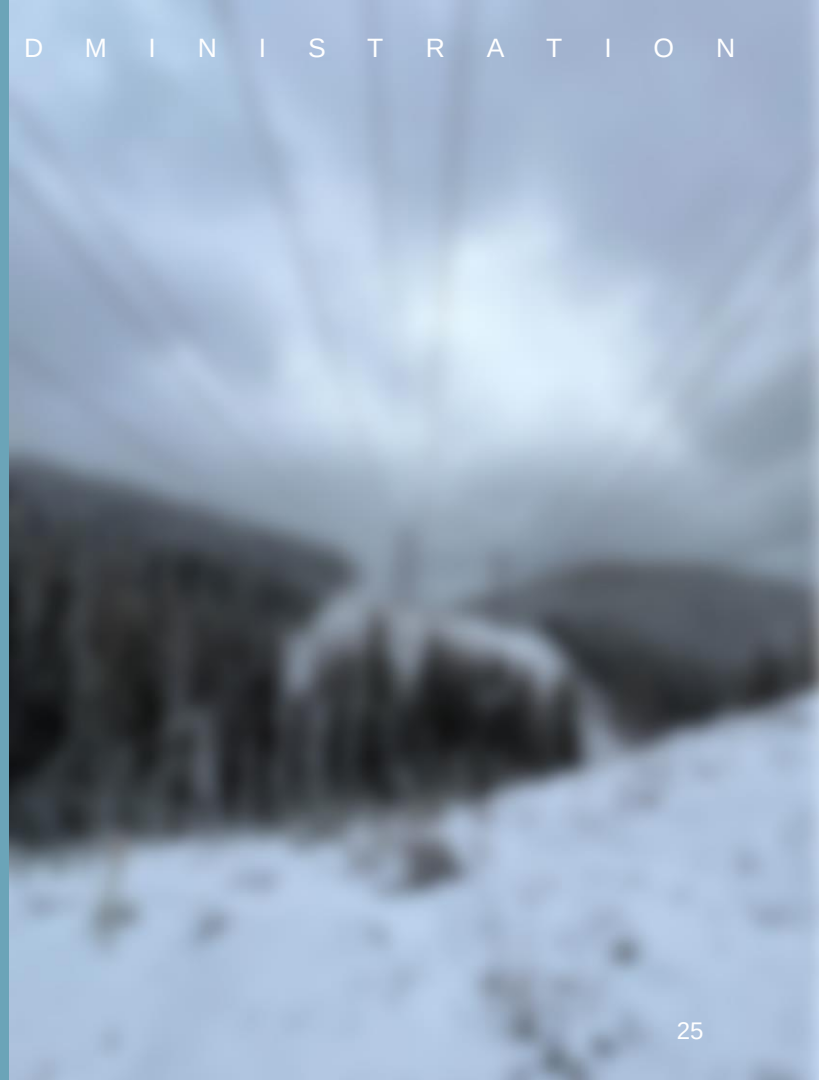
Natural Gas Assessment: Key takeaways

- Including new NG would not change results or lower portfolio costs for the base case or any associated sensitivities. This depends on the following assumptions:
  - A new NG plant built for BPA could not be online before 2035 and would only serve as a bridge resource until 2045
  - Carbon emission costs are considered
  - SMRs beginning operation in 2035 are available and eligible for Inflation Reduction Act tax credits, will not cost substantially more than baseline estimates, and will remain online for 60 years
- Using the above assumptions, the NG assessment for RP24 tests whether the solver would have selected a new NG resource.

Resource Acquisition Process

Eric Federovitch

Manager, Long Term Sales and Purchases



BPA Power Services and Resource Acquisition

- BPA is defining its processes for potential resource acquisitions, and refining existing ones related to assessing and implementing cost-effective uprates of existing FCRPS projects

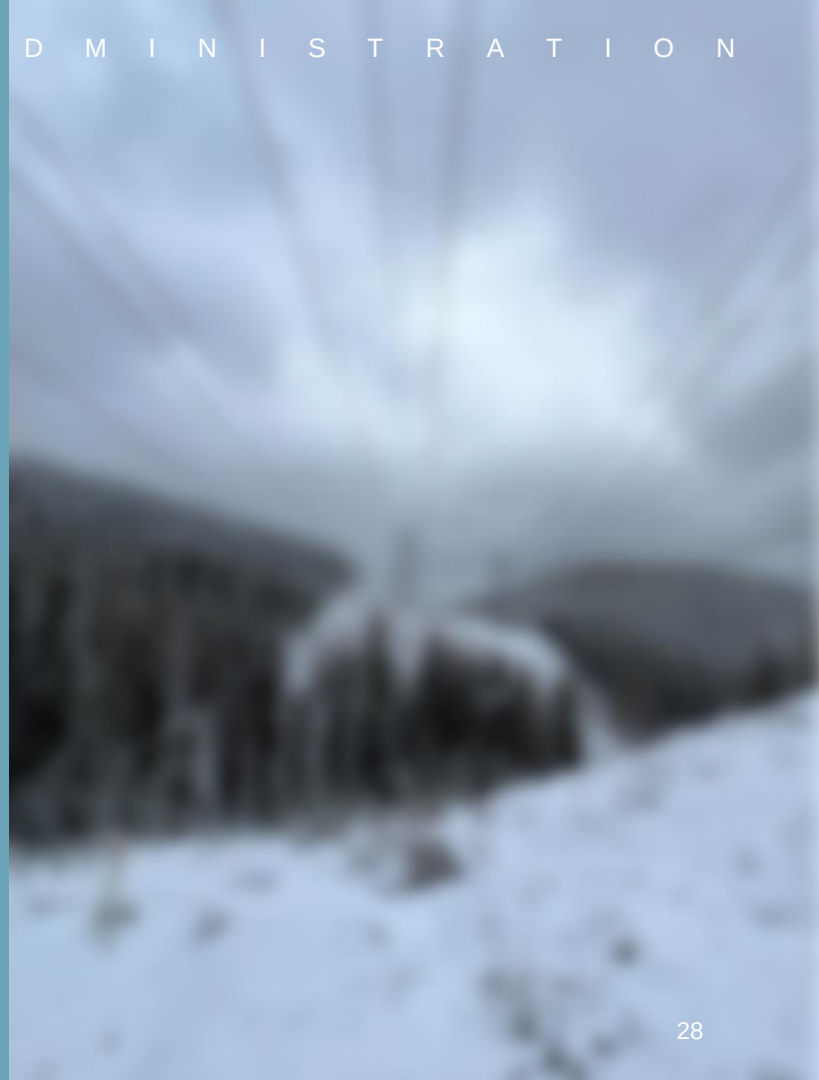
- We continue to explore the possibility of solidifying a resource acquisition commitment before new long-term power sales contracts are signed, as well as opportunities to modernize 6(c) procedures and policy in collaboration with the Northwest Power and Conservation Council

- RP26 will provide information on the type, timing, and quantity of potential resource solutions which may be used to inform a formal resource solicitation process

Acquiring Major Resources – Summary

- Provider of Choice process and Resource Programs inform major resource acquisition decisions, but are not the decision making processes
- BPA is aware of and considering potential approaches to acquire resources on the timeline needed to meet customer obligations post-2028
  - BPA and Council staff are reviewing the current Section 6(c) Policy and considering revisions to update the Policy consistent with the NW Power Act and efficient acquisition practices
  - BPA has benchmarked processes of other utilities to gather best practices and insights to incorporate into process for potential resource acquisitions
- Continuing to explore cost effective opportunities e.g. FCRPS uprates, cost-effective market purchases and minor supply-side acquisitions, experimental 6(d) acquisitions
- Under development project plan to include: Commercial solicitation and contracting, legal/6(c), environmental compliance, transmission considerations, financial

Questions and Discussion



Appendix

Resource Solutions

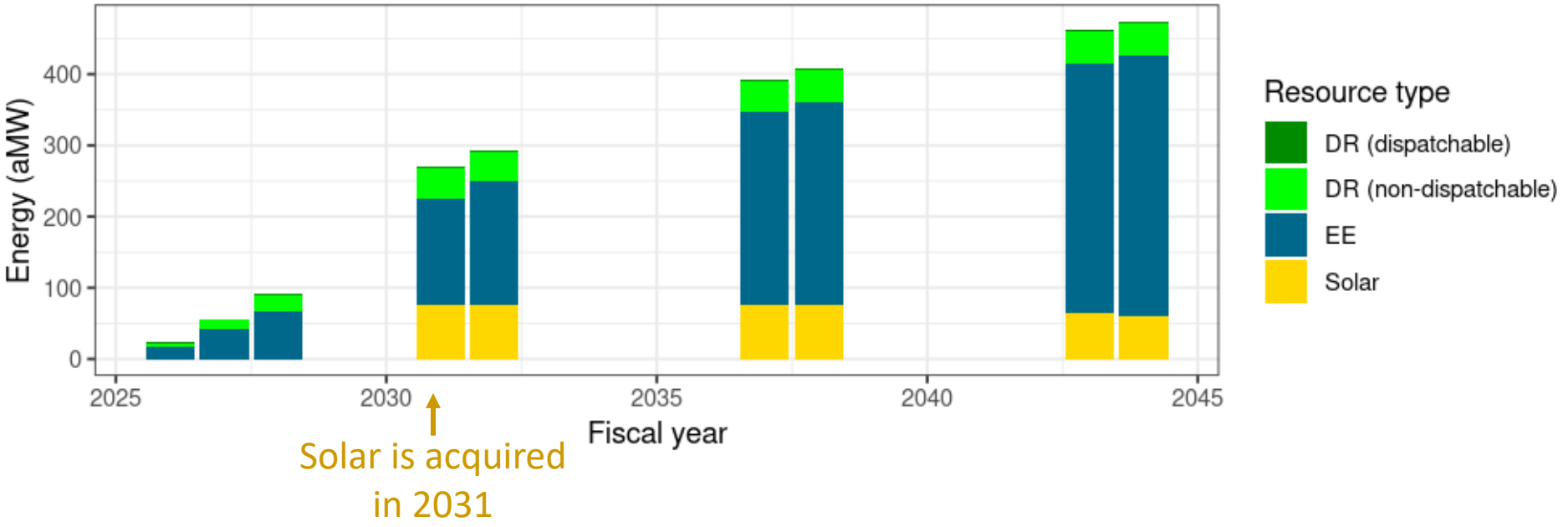
Base scenario: EE and DR

- Non-dispatchable DR programs acquired:
  - Residential Time of Use (TOU) Pricing
  - Utility Demand Voltage Reduction (DVR)
- Dispatchable DR programs acquired:
  - Commercial, industrial, and residential Critical Peak Pricing (CPP)
- EE achieved by 2045:
  - Total: **564 aMW**
  - Serving BPA load: **395 aMW***
- More in-depth EE + DR analysis to come

*About 70% of the total EE achieved by BPA reduces the BPA load obligation. The remainder reduces customer obligations. The percentages vary by EE measure and by customer, but for modeling purposes, we assume 70% for all EE programs.

Base scenario: Mid-C annual aMW

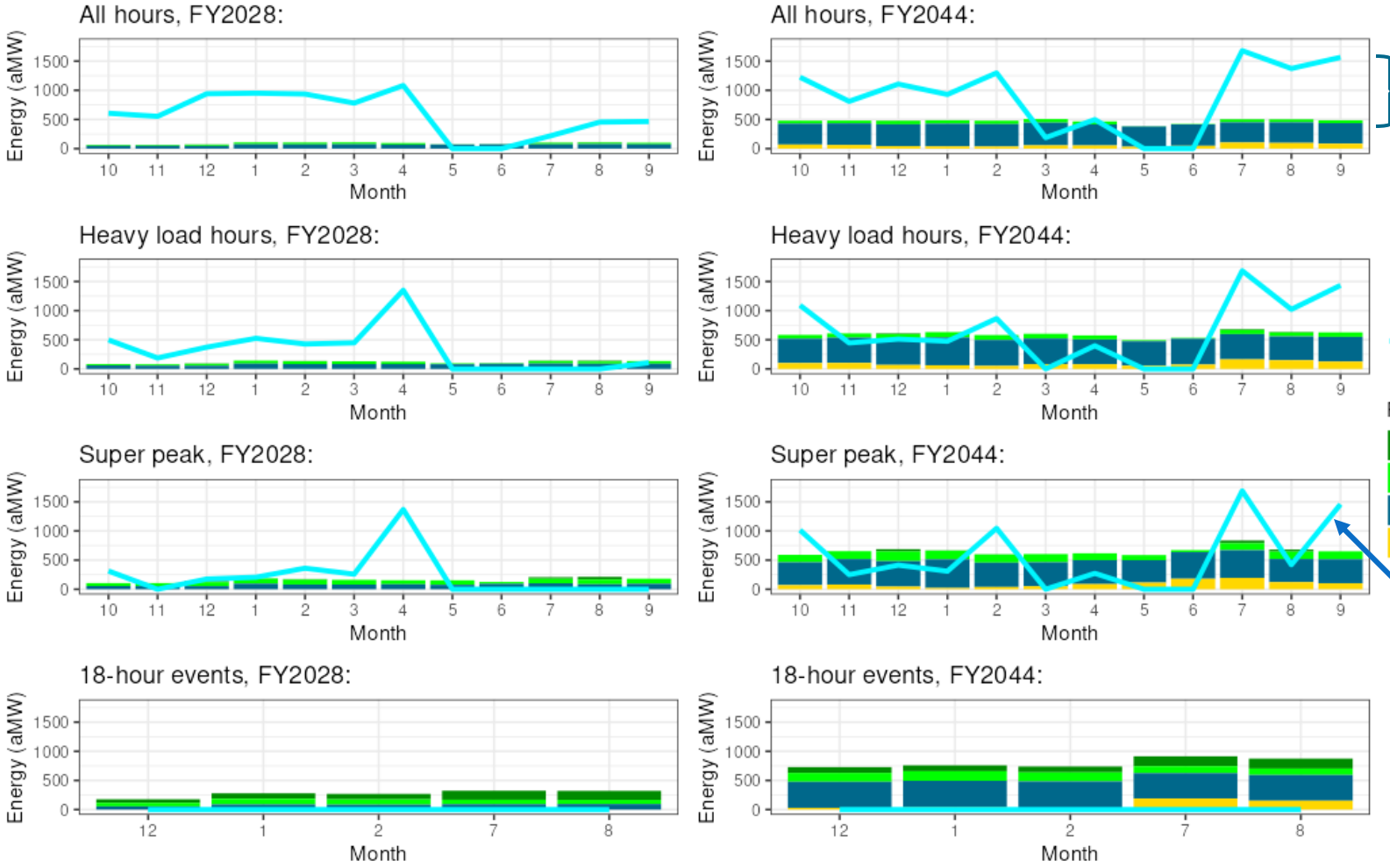
EE and DR programs are started in 2026 and ramp up over time



Solar is acquired in 2031

EE aMW shown is the portion serving BPA load. Total EE acquired in Mid-C is 30% higher.

Base scenario, Mid-C needs and resource contributions:



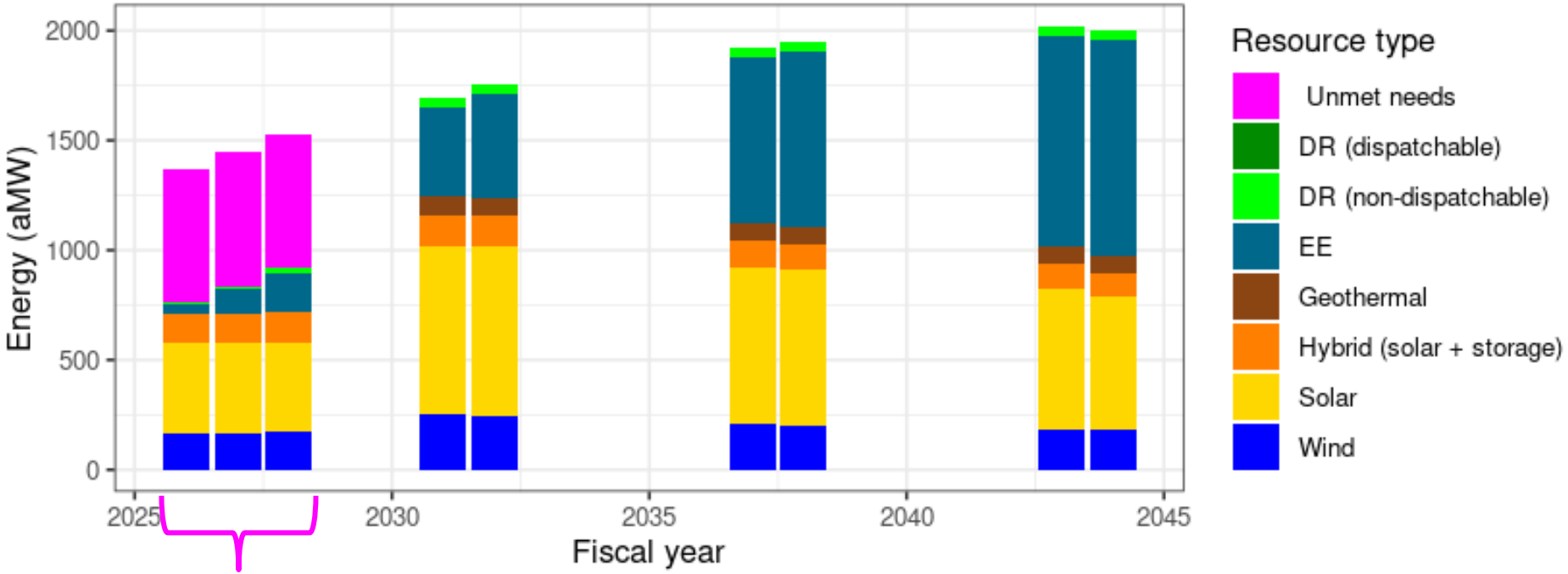
Market purchases fill in remaining needs

Needs are for P10 water conditions (except 18 hr capacity)

Market limits sensitivities: Key takeaways

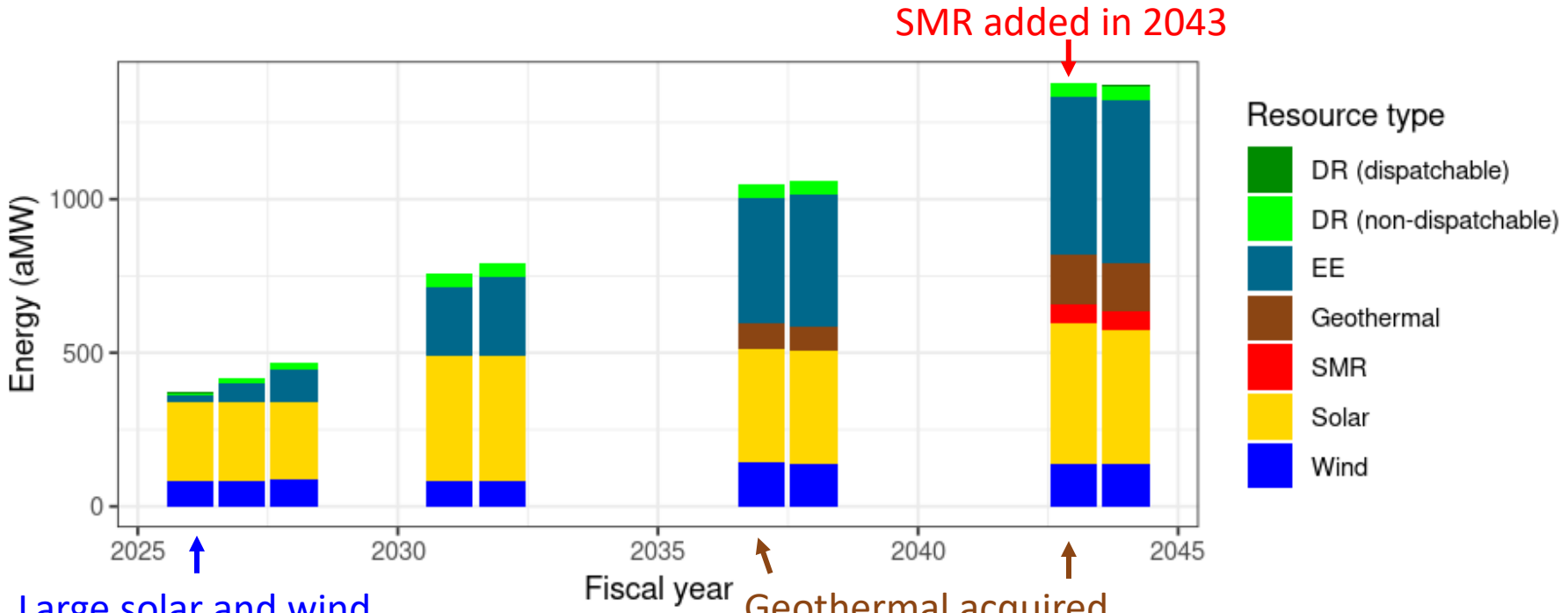
- Needs in 2026-2028 have a strong influence on results
  - Meeting needs in winter and April in this period requires large market purchases (or resources not currently in the model)
- Resource acquisitions are driven primarily by flat energy needs
- Market purchases are replaced primarily with solar and wind

‘No market’ sensitivity: Mid-C annual aMW

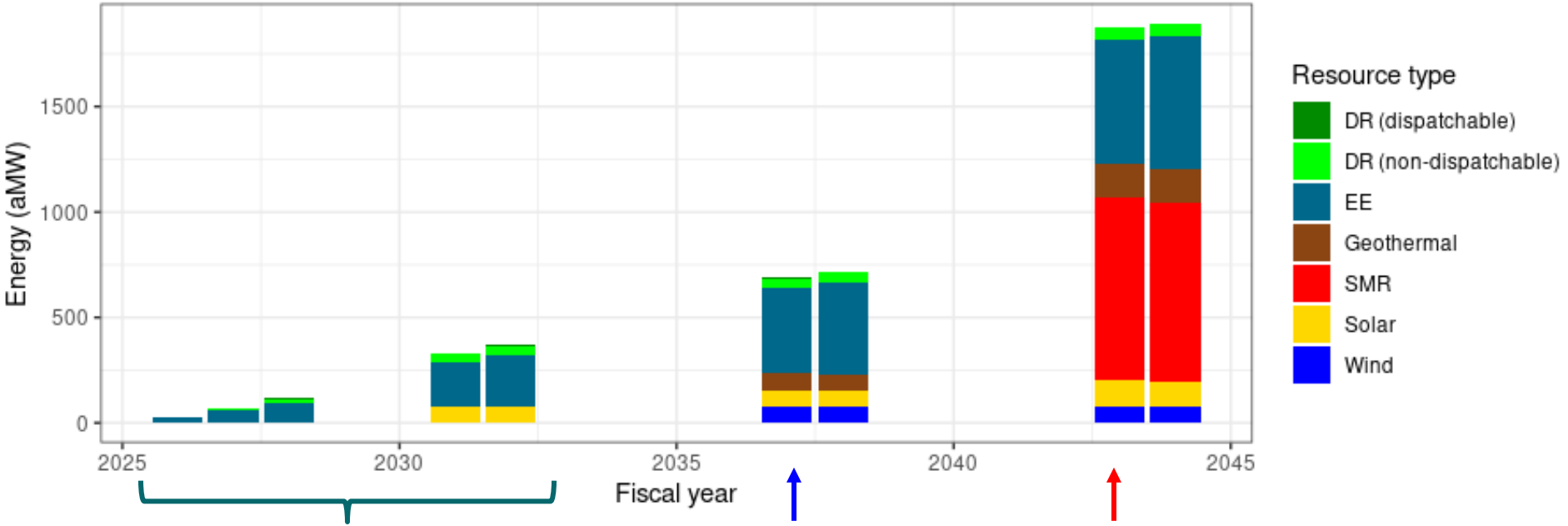


Months without enough resources to meet needs: Nov – Feb and April

‘Reducing market purchases to 0’ sensitivity: Mid-C annual aMW



Medium load adder: Mid-C annual aMW



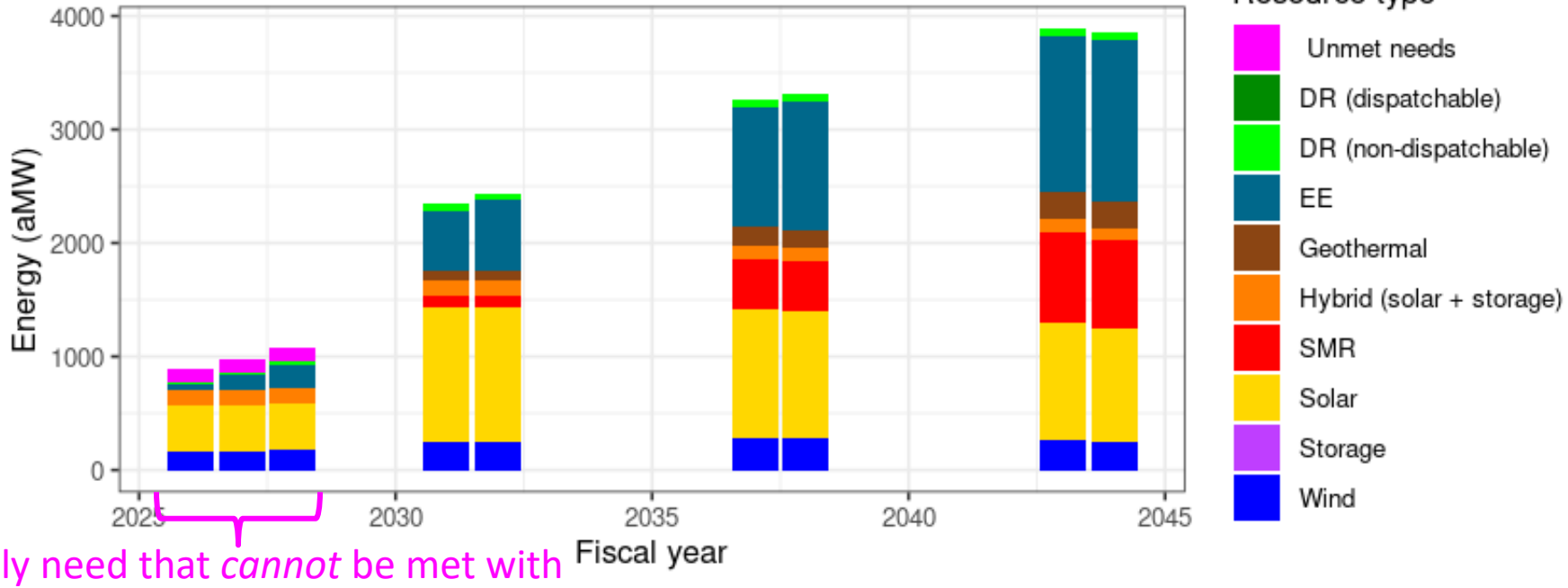
2026-2032 acquisitions same as Base Scenario

Wind and geothermal added in 2037

Most acquisitions happen in 2043

High load adder: Mid-C annual aMW

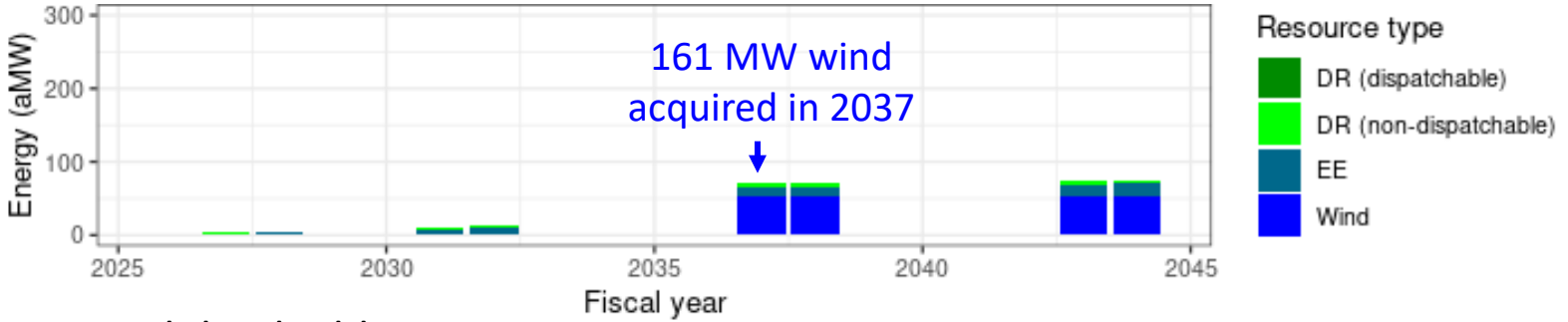
New, large acquisitions made in every available year
(i.e., 2026, 2031, 2037, and 2043)



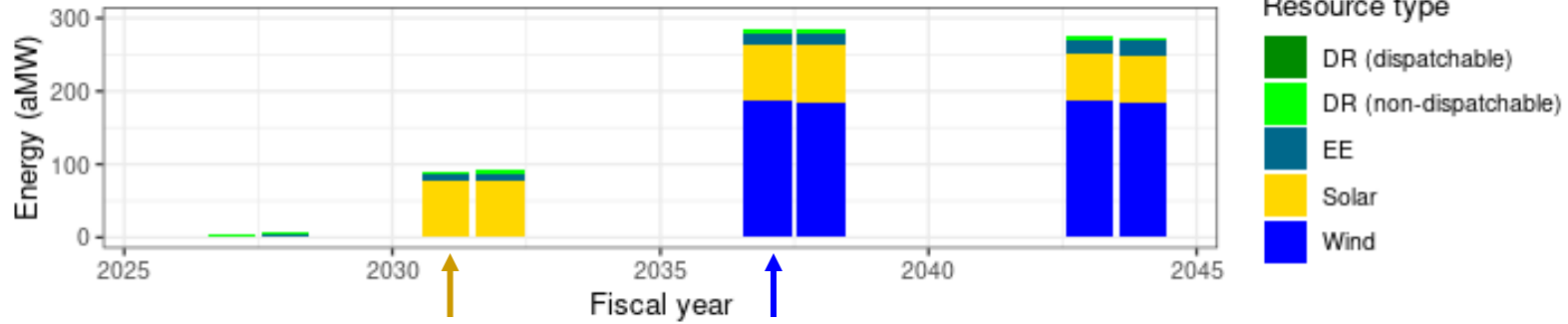
Only need that *cannot* be met with resources in the model: Apr '28 HLH

Load adders: SWEDE annual aMW

Medium load adder:



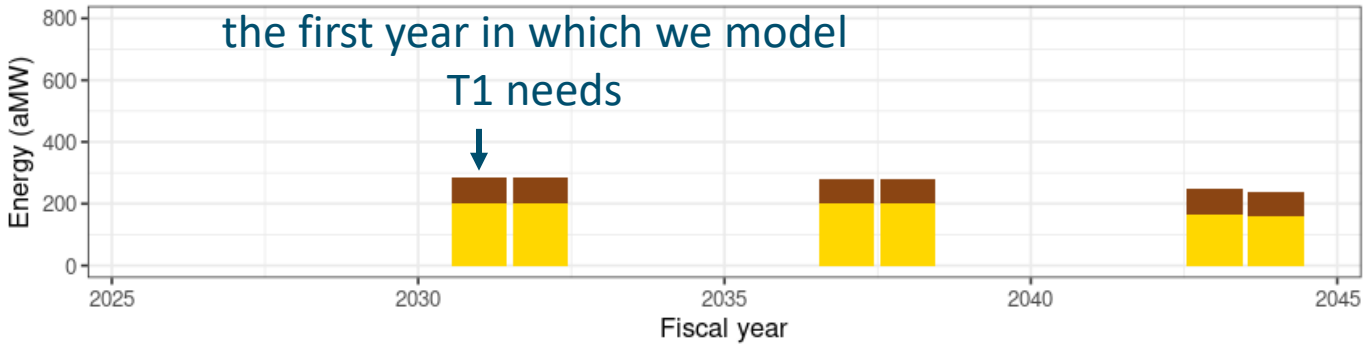
High load adder:



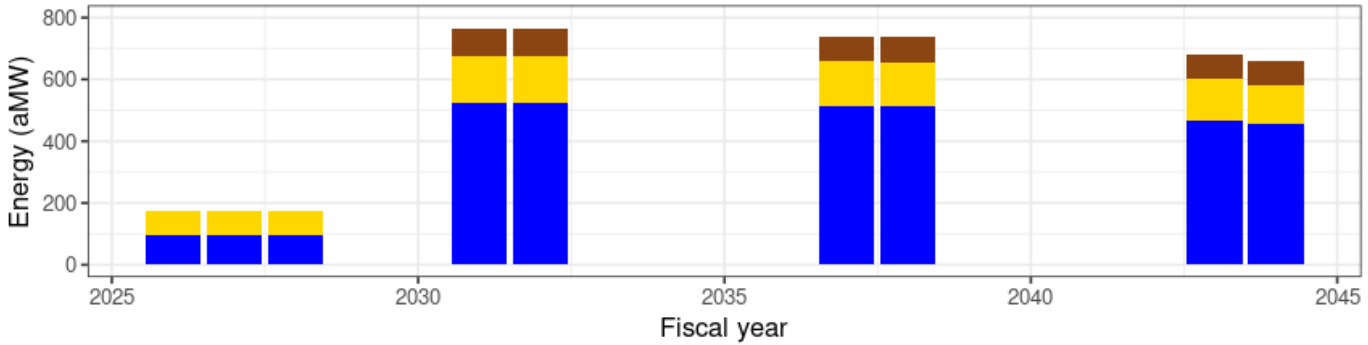
Tier 1 augmentation: annual aMW

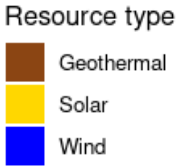
MIDC:

Resources all acquired by 2031, the first year in which we model T1 needs



SWEDE:

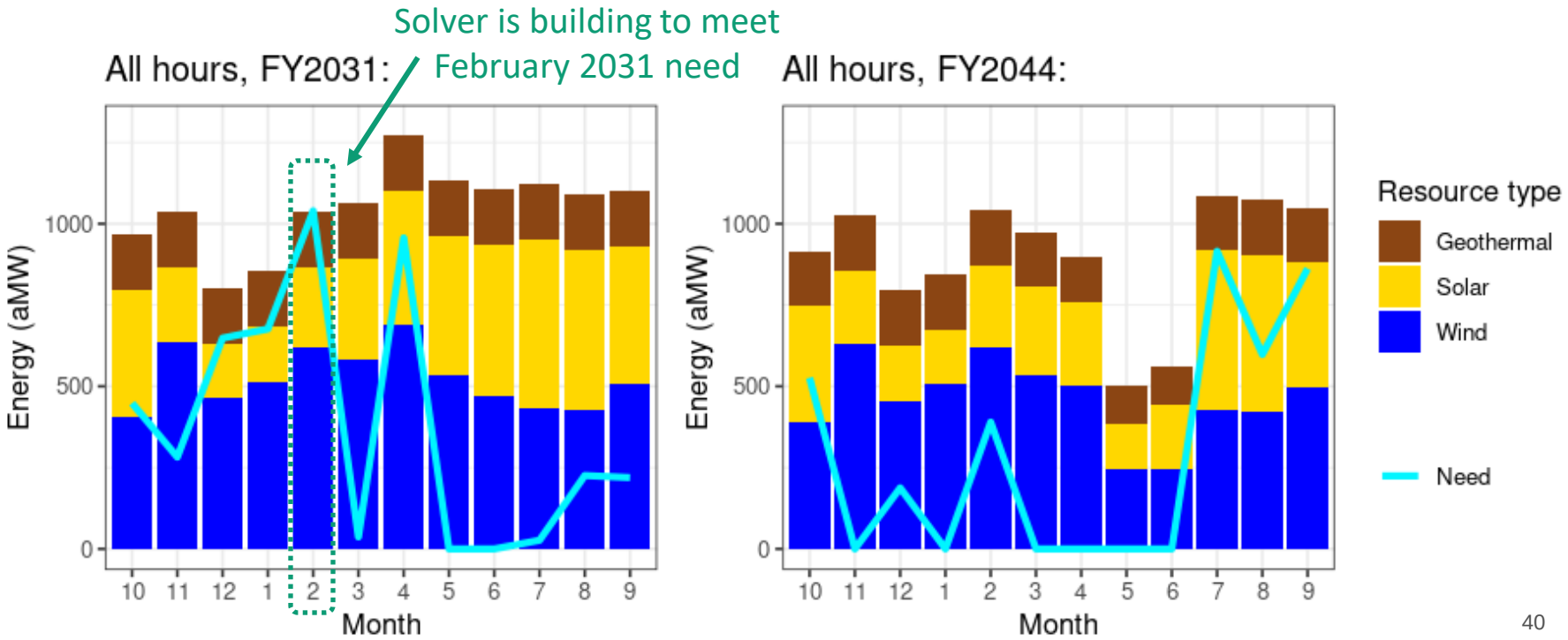




Most of the energy is generated in SWEDE

Tier 1 augmentation: monthly aMW

In most months, generation is much greater than needs, even under P10 conditions



Natural Gas Assessment

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

	Not Selected
	Likely Selected if Available
	Likely Selected

*2035 is the earliest date we've assumed BPA could have a new resource online considering EIS, interconnection, and other necessary processes.

If BPA could get a NG resource online sooner, temporarily acquire output from an existing plant, or invest in NG resources that transition to zero emissions (through clean fuels or carbon sequestration), NG resources may help reduce costs of meeting needs under more sensitivities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-145:
Western Pool Reserve Sharing Program

NWPP RSG
POWERED BY WPP

Northwest Power Pool
Reserve Sharing Program Documentation

NWPP Reserve Sharing Program 1.18.2006
RSG Committee Approved, effective: 10.1.2025

NWPP Reserve Sharing Documentation

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NWPP Reserve Sharing Program

A. INTRODUCTION AND OVERVIEW

Standards established by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) require all Balancing Authorities to carry reserve for defined categories of contingencies. As permitted by NERC and WECC standards, Participating Balancing Authorities within the Northwest Power Pool (NWPP) have instituted the NWPP Reserve Sharing Program for Contingency Reserve.

By sharing Contingency Reserve, Participants are entitled to use not only their own "internal" reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. Except when communication links are down or the Reserve Sharing Computer System is not functioning, the NWPP Reserve Sharing Program is automated, operating through direct communication of data and Contingency Reserve deployment signals between the Reserve Sharing Computer System and the Participating Balancing Authorities. The WPP Staff is responsible for preparing and submitting required NERC and WECC compliance reports, and responding to compliance audits, on behalf of the NWPP Reserve Sharing Group for BAL-002. Participants are relieved of BAL-002 compliance reporting obligations, and do not report to NERC or WECC on BAL-002 compliance individually.

This document describes how the NWPP Reserve Sharing Program works. It covers:

- key terminology for the NWPP Reserve Sharing Program (Section B),
- an overview of the key elements of the NWPP Reserve Sharing Program (Section C),
- how much Contingency Reserve each participant is required to carry (Attachment A),
- what events allow participants to deploy their own Contingency Reserve, and, if necessary, request assistance reserve, how a participant may request assistance reserve from other participants (Attachment B and Section E),
- participants' obligations to supply assistance reserve (Section F),
- eligibility to participate in reserve sharing and how eligible Balancing Authorities become participants (Section G),
- the roles and responsibilities of participants, the WPP Staff, and others (Section H),
- general data requirements and the functions of the reserve sharing computer system (Section I),
- data requirements related to requests for assistance reserve (Section J),
- how participants settle when assistance reserve is supplied under the NWPP Reserve Sharing Program (Section K and Attachment D),

- tracking and reporting procedures related to the NWPP Reserve Sharing Program (Section L),
- identification of "zones" within the NWPP Reserve Sharing Group for delivering reserve energy, and the sequence in which assistance reserve from adjacent zones is deployed if the assistance reserve inside a given zone is insufficient to meet a contingency (Section M and Attachment C);
- backup procedures participants will use if the communication links that enable automated reserve sharing go down (Section N and Attachment E);
- procedures for addressing issues that affect the NWPP Reserve Sharing Program when the process under the *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002* is insufficient (Section O);
- an explanation of why the NWPP Reserve Sharing Group does not activate Contingency Reserve during operation of BPA remedial action schemes that are designed to suspend automatic generation control (Attachment M),

This document includes several attachments, some of which have been noted above. The full set of attachments and their titles are as follows:

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zone and Levels

Attachment D – Process Chart

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Transmission Mapping and Tag Template Change Process

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Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – Typical Planning MSSC in Real Time, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

B. KEY TERMINOLOGY

The terms identified below have the meanings given to them in this document for purposes of the NWPP Reserve Sharing Program. Most terms defined by NERC or the WECC are conformed to the NERC or WECC definitions, but some terms' definitions may not be identical to those established by NERC or the WECC.

ACE: Area Control Error, as defined in the NERC Glossary.

Actual Net Interchange (NI_A): Actual Net Interchange, as defined in the NERC Glossary.

Agency Agreement: The *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002*, as initially effective on July 1, 2008, together with any subsequent amendments or restatements.

Assistance Reserve: Contingency Reserve of one Participant that is delivered to another Participant in response to a Reserve Sharing Request.

BAL-002: For the RSG, BAL-002 means:

- NERC Reliability Standards BAL-002 and BAL-002-WECC
- And with respect to a Participant, those provisions of the foregoing (or any substantially similar standard) applicable to the Participant by law or regulation.

Balancing Authority (BA): Balancing Authority, as defined in the NERC Glossary.

Balancing Authority Area (BAA): Balancing Authority Area, as defined in the NERC Glossary.

Balancing Authority Area MSSC: A NWPP Reserve Sharing Group Participant Balancing Authority and its Balancing Authority Area's real-time MSSC based on actual configurations and provided to the Reserve Sharing Computer System via ICCP in real time.

Balancing Contingency Event: Balancing Contingency Event, as defined in the NERC Glossary.

Contingency Event Recovery Period: Contingency Event Recovery Period, as defined in the NERC Glossary.

Contingency Reserve: Contingency Reserve, as defined in the NERC Glossary.

Contingency Reserve Available (CRA): Contingency Reserve committed by a Participating Balancing Authority, which the Participating Balancing Authority reports to the Reserve Sharing Computer Program, that:

- is fully deployable within ten minutes for use as Internal Reserve (except for amounts reported as already deployed for Qualifying Events);
- is fully deployable within ten minutes of an Assistance Reserve Sharing Request for delivery (except for amounts reported as already deployed for Qualifying Events); and
- is sustainable for 60 minutes from the time of a request for Assistance Reserves.

Subject to the foregoing requirements, a Participating Balancing Authority's Contingency Reserve Available:

- will, for monitoring purposes, be deemed to include a Participant's Contingency Reserve reported as available for deployment; and
- may include Contingency Reserve purchased or otherwise transferred to the Participating Balancing Authority. Reporting ACE transferred from one Participant to another Balancing Authority Area would be considered a transfer; and
    - if arranged from another entity from outside of the Participant's zone (as detailed in Attachment C) and deployed for a valid request, details of deployment shall be reported to the WPP Staff.
- may include load committed to be shed for Contingency Reserve if a Participant is in an EEA; and
- must exclude Contingency Reserve the Participating Balancing Authority has sold to any other party.

A Participating Balancing Authority's Contingency Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

Contingency Reserve Obligation (CRO): As specified in Attachment A to this document, Contingency Reserve Obligation is the minimum amount of Contingency Reserve that must be carried by a particular Participant for its Balancing Authority Area(s) or by the NWPP Reserve Sharing Group as a whole (as the context requires) to respond to Qualifying Events. Although the acronym "CRO," as used in this document, may sometimes designate base calculation of a Participating Balancing Authority's Contingency Reserve Obligation (before adjustments described in Attachment A), the written term "Contingency Reserve Obligation"

as used in this document refers to the total amount of Contingency Reserve that must be carried for a Participant's Balancing Authority Area(s) (or the NWPP Reserve Sharing Group as a whole), taking into account all applicable adjustments specified in Attachment A.

Firm Demand: Firm Demand, as defined in the NERC Glossary.

Internal Reserve: The Contingency Reserve of a Participating Balancing Authority when deployed to respond to a Qualifying Event on the Participating Balancing Authority's own system (as opposed to Contingency Reserve delivered as Assistance Reserve to another Participating Balancing Authority).

Long-Term Zonal MSSC Limit: An identified normal system MSSC documented in Attachment K.1. by each zone's Participant Balancing Authority/Balancing Authority Areas.

Most Severe Single Contingency (MSSC): The Most Severe Single Contingency, as defined in the NERC Glossary.

NERC Glossary: The NERC Glossary of Terms Used in Reliability Standards.

North American Electric Reliability Corporation (NERC): A self-regulatory nonprofit organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada, whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards, assesses reliability annually via 10-year and seasonal forecasts, monitors the bulk power system, and educates, trains, and certifies industry personnel.

Northwest Power Pool (NWPP): The geographic area encompassed by the electric systems of the NWPP Agreement Signatories. There is also a separate corporation named "Northwest Power Pool," which provides staffing and other resources to support implementation of the NWPP Agreement. In general, when this document refers to the Northwest Power Pool or the NWPP, it is referring to the geographic area and the associated electric power systems of the NWPP Agreement Signatories.

NWPP Agreement: A multilateral agreement to promote cooperation among participating organizations to achieve reliable operation, coordinate generation operation and power system planning, and assist in planning of transmission within the NWPP area.

NWPP Agreement Signatory (Signatory): An entity that is a party to the NWPP Agreement.

NWPP Reserve Sharing Group: The group composed of all Participants, collectively.

NWPP Reserve Sharing Group Long-Term MSSC Limit: The identified long-term maximum limit of the NWPP Reserve Sharing Group's MSSC is the largest Long-Term Zonal MSSC Limit as documented in Attachment K.1.

NWPP Reserve Sharing Group Reporting ACE: The algebraic sum of the Reporting ACE of the Participant(s) experiencing the RBCE (or multiple BCEs occurring within 60 seconds) and the Reporting ACE of those Participant(s) delivering Assistance Reserve to the Requesting Participant(s) -see Attachment C "Reserve Sharing Zones and Levels", including any Participant delivering transferred Assistance Reserve.

NWPP Reserve Sharing Program: The procedures, data, computer programs, and related information and requirements described in this document that enable Participants to request and provide Assistance Reserve as needed to respond to Qualifying Events.

Operating Plan: Operating Plan, as defined in the NERC Glossary.

Operating Process: Operating Process, as defined in the NERC Glossary.

Operating Reserve: Operating Reserve, as defined in the NERC Glossary.

Participating Balancing Authority or Participant: An entity that (a) operates one or more Balancing Authority Areas and (b) has become a participant in the NWPP Reserve Sharing Program as described in Section G.1. The terms "Participant" and "Participating Balancing Authority" are used interchangeably in this document. Attachment H contains a list of the Balancing Authority Areas of the current Participating Balancing Authorities.

Qualifying Event: Those events designated in Attachment B of this document as Qualifying Events.

Recovery Reporting ACE Target: The average value of a requesting Participant's Reporting ACE in the 16-second interval immediately prior to the start of the Qualifying Event (or zero, whichever is less) or the average value of a Participant's Reporting ACE that is providing Assistance Reserve in the 16-second interval immediately prior to the request of Assistance Reserves (or zero, whichever is less) based on EMS scan rate data.

Reliability Coordinator (RC): Any one or more organizations performing the NERC-registered function (or its equivalent in Canada) of reliability coordination within the Northwest Power Pool.

Reportable Balancing Contingency Event: Reportable Balancing Contingency Event, as defined in the NERC Glossary.

Reporting ACE: Reporting ACE, as defined in the NERC Glossary.

Reserve Sharing Computer System: The software and hardware used for automated reserve sharing under the NWPP Reserve Sharing Program.

Reserve Sharing Request: A request by Participating Balancing Authority that has satisfied the conditions specified in Section E.2 for delivery of Assistance Reserve.

Reserve Sharing Zone: A designated set of Balancing Authority Area(s) within the Reserve Sharing Group that is separated from other Balancing Authority Area(s) within the Reserve Sharing Group by transmission facilities that have been shown through studies to constrain reserve deliveries, at times, between the designated set and the other Balancing Authority Areas. Attachment C to this document identifies the Reserve Sharing Zones that have been established for the NWPP Reserve Sharing Program, together with the sequence through which Assistance Reserve is deployed for each Reserve Sharing Zone.

RSG Committee: The committee established under the terms of the NWPP Agreement to administer the NWPP Reserve Sharing Program.

Scheduled Net Interchange (NI_S): Scheduled Net Interchange, as defined in the NERC Glossary.

System Operator: System Operator, as defined in the NERC Glossary.

Third-Party Generation: Any generating resource that is within the metered boundaries of the Balancing Authority Area of a Participating Balancing Authority but is neither owned by nor under contract to that Participating Balancing Authority.

WECC Soft Price Cap: The price cap adopted by the Federal Energy Regulatory Commission in *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121 (2000) and *Western Electric Coordinating Council*, 133 FERC ¶ 61,026 (2010), subject to the guidance provided by the Federal Energy Regulatory Commission in *ConocoPhillips Company, et al*., 175 FERC ¶ 61,226 (2021)

WECC Operating Reserve - Supplemental: WECC Operating Reserve - Supplemental is the portion of Operating Reserve consisting of:

- generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Contingency Event Recovery Period following a contingency event; or
- load fully removable from the system within the Contingency Event Recovery Period following the contingency event;

provided, however, that for purposes of the NWPP Reserve Sharing Program (as required by WECC Standard BAL-002-WECC-3), WECC Operating Reserve - Supplemental must also be:

- capable of fully responding within ten minutes.

Western Electricity Coordinating Council (WECC): A nonprofit corporation with the mission to foster and promote reliability and efficient coordination in the Western Interconnection.

WPP Staff: The employees of the Northwest Power Pool Corporation doing business as the Western Power Pool.

C. OVERVIEW OF KEY RESERVE SHARING PROGRAM ELEMENTS

C.1. How Much Contingency Reserve a Participating Balancing Authority Must Carry (Contingency Reserve Obligation)

The processes for calculating how much Contingency Reserve each Participant must carry for its Balancing Authority Area(s), and the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, are set forth in Attachment A to this document along with the process chart as reflected in Attachment D.

C.2. When a Participating Balancing Authority May Deploy Contingency Reserve and Request Assistance Reserve (Qualifying Events)

A Participating Balancing Authority must experience a "Qualifying Event" before it is entitled to deploy any portion of its Contingency Reserve Obligation (as Internal Reserve) or request Assistance Reserve. The definition of Qualifying Event is set forth in Attachment B to this document.

C.3. What a Participating Balancing Authority Must Do Before Requesting Assistance Reserve

A Participating Balancing Authority must fully commit an amount of its Balancing Authority Area's Internal Reserve that equals or exceeds the requesting Participant's CRO requirement to the NWPP before requesting Assistance Reserve to respond to a Qualifying Event. This requirement is more fully explained in Section E.2 of this document. There are also requirements concerning the timing and duration of Assistance Reserve Sharing Requests, which are set forth in Section E.3.

C.4. Where to Find Additional Information on Participant Eligibility and Obligations

Eligibility

Provisions governing eligibility to participate in the NWPP Reserve Sharing Program are in Section G of this document.

Additional Operating Reserve for R3 and R4 of WECC BAL-002-WECC-3

Section D.4 describes Participating Balancing Authorities' obligations to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

Data Obligations

Section I contains information on the data requirements for the general operation of the NWPP Reserve Sharing Program, as well the functions of the Reserve Sharing Computer System. Section J describes data requirements for making and responding to Reserve Sharing Requests.

Providing Assistance Reserve

Participants' obligations to provide Assistance Reserve are explained in Section F.

Restoring Contingency Reserve Following Deployment

Section E.6 describes Participants' obligations to restore their Contingency Reserve following deployment (either as Internal Reserve or Assistance Reserve).

D. RESERVE REQUIREMENTS

D.1. How NWPP Reserve Sharing Program Rules Relate to BAL-002

The NWPP Reserve Sharing Program is intended to enable the NWPP Reserve Sharing Group to comply with BAL-002, as well as certain additional rules the NWPP Reserve Sharing Group has elected to adopt for itself.

Participants are required at all times to meet the requirements of BAL-002, as revised, supplemented, or superseded from time to time in accordance with applicable NERC, WECC, or regulatory procedures. BAL-002 constitutes the foundation on which the NWPP Reserve Sharing Group rules are built. Compliance with the NWPP Reserve Sharing Group rules for Contingency Reserve is intended to ensure compliance with the BAL-002, but cannot serve to excuse any compliance failure related to the NERC or WECC standards.

NERC Standard BAL-002-3 requires Balancing Authorities (or reserve sharing groups) to recover, within the Contingency Event Recovery Period, from Reportable Balancing Contingency Events (subject to certain exceptions).

WECC Standard BAL-002-WECC-3 governs Contingency Reserve, but also includes requirements (set forth in Sections R3 and R4 of BAL-002-WECC-3) for additional Operating Reserve that must be carried by Participants engaging in certain types of transactions involving purchases from units supplying Contingency Reserve or sales of Operating Reserve. This document addresses, at Section D.4, requirements for Participating Balancing Authorities to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

D.2. Contingency Reserve Obligations and Associated Requirements Related to WECC Operating Reserve - Supplemental

Section 1 of Attachment A to this document provides a detailed explanation of how to calculate the Contingency Reserve Obligation for each Participating Balancing Authority. Section 1 also explains the manner in which the Participating Balancing Authorities' Contingency Reserve Obligations are combined to yield an aggregate obligation for the NWPP Reserve Sharing Group. Section 2 of Attachment A specifies what portion of Participating Balancing Authorities' Contingency Reserve Obligations must be carried as permitted sources of WECC Operating Reserve - Supplemental. Every Participating Balancing Authority must include in its operating procedures provisions that require it to:

a. maintain and have available an amount of Contingency Reserve Available that is equal to or greater than its Contingency Reserve Obligation,

b. perform such calculations as may be necessary (including consideration of transmission constraints) to ensure that it can deploy Contingency Reserve reported as available, and

c. deploy its Contingency Reserve Available for Qualifying Events as provided in this document.

Section 3 explains the Participating Balancing Authorities calculation of Contingency Reserve Obligation(s) when communications with the Reserve Sharing Computer System are disrupted.

D.3. Additional Policies Governing Contingency Reserve

a. <u>No Double Counting</u>

As expressed in the policies of the RSG Committee, multiple Participants may not count the same portion of resource capacity (*e.g.,* reserves from jointly owned generation) toward any portion of their Contingency Reserve Obligations, and the NWPP Reserve Sharing Group rules do not permit this.

b. <u>Contingency Reserve Available</u>

All Participants must continuously calculate and update their Contingency Reserve Available. A Participating Balancing Authority's Contingency

Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

c. Purchased Power

To provide flexibility in recovering from a Qualifying Event, any Participant may use power purchased from another Participant (or another supplier) to meet its Contingency Reserve Obligation. Any Participant that uses purchased power for recovery must report the source Balancing Authority(s) of the purchased power, the time the power was purchased, the start time and ramp rate for the mutually agreed-upon purchased power (or transaction). The WPP Staff will be responsible for determining whether a Participant providing purchased power fulfilled its obligations to deploy Contingency Reserve to enable the NWPP Reserve Sharing Group to comply with BAL-002. The requesting Participant must also arrange for transmission for delivery of the power. If the Balancing Authority from which the power was purchased is not a Participant in the NWPP Reserve Sharing Program, then any failure of the selling Balancing Authority to deliver the purchased power will be deemed, for purposes of the NWPP Reserve Sharing Program, as a failure to deliver of the Participant relying on the purchased power.

d. Aggregate Contingency Reserve Available

The aggregate Contingency Reserve Available for the NWPP Reserve Sharing Group (together with any Contingency Reserve deployed for Qualifying Events) must at all times equal or exceed both the NWPP Reserve Sharing Group's Most Severe Single Contingency and its combined Contingency Reserve Obligation.

e. RSG Committee Responsibilities; Monitoring and Follow-Up

The RSG Committee is responsible for developing guidelines and arranging for periodic reporting of the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and the Contingency Reserve Available within the NWPP Reserve Sharing Group. WPP Staff monitors Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems with deficient or poorly performing Participants, for developing remedies and proposed solutions, and for identifying and implementing any follow-up actions.

f. Determination of NWPP Reserve Sharing Group's Most Severe Single

Contingency

Each Participant is responsible for (i) determining, based on appropriate system modeling and applicable NERC definitions and guidelines, the Most Severe Single Contingency for its Balancing Authority Area(s), (ii) reporting its Most Severe Single Contingency determinations to the WPP Staff and making sure they are correctly reflected in Attachment K, and (iii) notifying WPP Staff whenever previously submitted Most Severe Single Contingency determinations need to be updated. The Most Severe Single Contingency for the NWPP Reserve Sharing Group at any given time is set by whichever of the Participants' Most Severe Single Contingencies is greatest at that time. The RSG Committee will review, at each of its meetings (and in any event no less than once a year), the NWPP Reserve Sharing Group's Operating Processes and its Most Severe Single Contingency to ensure the BAA MSSC's in Attachment K and other applicable tables are up to date and comply with applicable NERC and WECC requirements.

g. Participants' Monitoring of Real-Time Most Severe Single Contingencies

Every Participant is responsible for determining and telemetering to the Reserve Sharing Computer System, as provided in Section I.1.g, its Most Severe Single Contingency (and any adjustments upward or downward) based on real-time operating conditions. When determining Most Severe Single Contingencies in real time, each Participant must take into account its real-time generation output and its real-time generation and transmission outages. Real-time adjustments to a Participant's Most Severe Single Contingency should be captured and updated every data scan cycle.

h. All Participants' Contingency Reserve Available Constitutes NWPP Reserve Sharing Program Contingency Reserve Available

The amount of Contingency Reserve carried by the Participants to meet the requirements of NERC, WECC, and the NWPP Reserve Sharing Program is calculated so as to meet the needs of the NWPP Reserve Sharing Group as a whole and the Contingency Reserve Available reported by each Participant is deemed to be Contingency Reserve Available to the NWPP Reserve Sharing Program. Accordingly, if any Participant activates a portion of its Contingency Reserve to respond to a Qualifying Event, this will constitute activation of a portion of NWPP Reserve Sharing Program Contingency Reserve, including for purposes of calculating whether the Qualifying Event constitutes a Reportable Balancing Contingency Event, even if the activation of Contingency Reserve is not for a Reportable Balancing Contingency Event and even if the affected Participant does not

make a Reserve Sharing Request. Any Qualifying Event affecting any Participant constitutes a Qualifying Event for the NWPP Reserve Sharing Group, and therefore, unless at the time of the Qualifying Event the affected Participant is in "non-participating" status, recovery from the Qualifying Event will be determined with respect to the NWPP Reserve Sharing Group as a whole, and not the individual Participant.

i. Participant Obligation to Respond to Reportable Balancing Contingency Events

A Participant that has experienced a Qualifying Event (within its Balancing Authority Area):

- shall recover its ACE within the 15-minute Contingency Event Recovery Period for any loss greater than 50 MW, and
- must, if the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events, take all commercially reasonable actions that are necessary, in its good-faith judgment, to enable the NWPP Reserve Sharing Group to recover its Reporting ACE according to the requirements of BAL-002. To fulfill this obligation, the Participant is expected, among other things, to (i) deploy its Contingency Reserve, and (ii) if the Participant meets the conditions specified in Section E.2 and cannot fully recover from the Qualifying Event with reserve capability on its own system (and any purchased reserve rights), make a Reserve Sharing Request.

For Qualifying Events that result from the loss of a jointly owned facility, affected Participants must use the total MW of facility output lost to determine whether the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events (rather than whatever portion of the lost output a given Participant may have scheduled or been entitled to).

j. NWPP Reserve Sharing Program Automation and Exceptions.

Every Participant is always in active status with respect to the Reserve Sharing Program. All Participants must continuously and automatically telemeter to the Reserve Sharing Computer System the data specified in Section I.1, (unless unable to do so due to failure of communications capabilities between the Participant and the Reserve Sharing Computer System). Every Participant must also indicate (unless unable to do so) whether its participation is through automatic or manual capabilities. Valid reasons for Participants to indicate manual participation mode include, but are not limited to: failure of inter-control center

communications protocol (ICCP) links, suspension of automatic generation control (AGC), and system testing.

D.4. Additional Operating Reserve: Obligations Under R3 and R4 of WECC BAL-002-WECC-3 and Compliance Documentation

a. Participants Must Carry Required Additional Operating Reserve

Each Participating Balancing Authority must carry, in addition to its Contingency Reserve Obligation calculated in accordance with Attachment A, sufficient Operating Reserve to fulfill the requirements of R3 and R4 of BAL-002-WECC-3.

b. Participants Must Maintain and Provide Documentation to Demonstrate Compliance

Each Participating Balancing Authority must maintain appropriate documentation for any periods during which it has implemented

- any Interchange Transactions (as that term is defined by NERC) (i) with counterparties that are not Participants, (ii) for which it was the sink Balancing Authority, and (iii) that were designated as part of the source Balancing Authority's WECC Operating Reserve - Supplemental; or
- any Operating Reserve transactions (x) with counterparties that are not Participants, and (y) for which it was the source Balancing Authority.

The Participating Balancing Authority's documentation must be sufficient to demonstrate that, during all relevant periods, it maintained additional Operating Reserve as required by R3 and R4 of BAL-002-WECC-3.

Each Participating Balancing Authority must, on at least a quarterly basis, submit summaries to the WPP Staff of transactions subject to R3 and R4 of BAL-002-WECC-3, in the form specified by the WPP Staff (in consultation with the Participating Balancing Authorities). Participating Balancing Authorities that prefer to submit this information to the WPP Staff on a more frequent basis (including through the Reserve Sharing Computer System in real-time) may do so in coordination with the WPP Staff.

In addition, all Participating Balancing Authorities must supply copies of supporting documentation to the NWPP Reserve Sharing Group (or the WPP Staff) promptly upon request.

c. Deployment of Additional Operating Reserve Not Restricted to Qualifying Events

Because the additional Operating Reserve necessary to comply with R3 and R4 of BAL-002-WECC-3 is incremental to Participants' Contingency Reserve Obligations, Participants are not limited in their use of this additional Operating Reserve to Qualifying Events. Participants are entitled to deploy this additional Operating Reserve to respond to interruption of Interchange Transactions (as described in BAL-002-WECC-3 R3) or fulfillment of Operating Reserve transactions (as described in BAL-002-WECC-3 R4) even if these do not constitute Qualifying Events.

E. REQUESTING ASSISTANCE RESERVE

E.1. Qualifying Events

The Qualifying Events that permit Participants to deploy Internal Reserve, and, if the conditions specified in Section E.2 are satisfied, request Assistance Reserve, are specified in Attachment B to this document.

E.2. Action Required Before Requesting Assistance Reserve

If a Participant experiences a Qualifying Event (Attachment B parts A, B, or C), the requesting Participant is entitled to request and schedule Assistance Reserve (up to the amount lost minus their Contingency Reserve Obligation to fully recover from the Qualifying Event) through the NWPP Reserve Sharing Program **only** after the requesting Participant has made commitments to use an amount of Internal Reserve that equals or exceeds the requesting Participant's Contingency Reserve Obligation. A Participant experiencing a Qualifying Event from Attachment B part D is entitled to request Assistance Reserve to meet Firm Demand as necessary after committing to use ALL Internal Reserve. At the time of the Participant's request for Assistance Reserve, the fulfillment of the Participant's obligation to fully commit its Contingency Reserve Obligation will be evaluated taking into account any Internal Reserve lost because of the Qualifying Event (such as the loss of a generator on which reserve was being carried, whether due to conditions affecting the generator itself or due to loss of generator interconnection or transmission facilities necessary for delivery of output from the generator). The amount of Contingency Reserve carried by any unit that is lost due to the Qualifying Event will be considered deployed and added to the used Contingency Reserve reported.

If the requesting Participant improperly reflects their UsedCR less than their $TotCRO_{CA}$, the program will reduce the amount of Assistance Reserves provided (not including any rounding that occurs programmatically) by the amount that UsedCR is less than $TotCRO_{CA}$.

a. Response to an Energy Emergency Alert 3

A Participant may utilize Contingency Reserve to respond to an Energy Emergency Alert 3 (EEA 3), as described in Attachment B, Section D.

If time allows, the Participant will notify the Western Power Pool staff on the 24/7 support line 503.673.6744 of the situation, which will enable the staff to provide any clarification that may be needed.

E.3. Timing of Requests for Assistance Reserve

After experiencing a Qualifying Event as described in Attachment B parts A, B, or C and fulfilling the conditions specified in Section E.2, a Participant that requires Assistance Reserve may submit a Reserve Sharing Request, however, must do so within 60 minutes following the start of the Qualifying Event. Reserve Sharing Requests must be made in whole MWs.

Even though an eligible Participant may make a Reserve Sharing Request at any time within 60 minutes following that start of a Qualifying Event, the NWPP Reserve Sharing Group may, with respect to administering the terms of the Agency Agreement, differentiate between Reserve Sharing Requests submitted promptly—that is, within four minutes following the start of the Qualifying Event—and Reserve Sharing Requests that are delayed beyond four minutes. The "four-minute rule" does not affect Participants' obligations to deliver Assistance Reserve to other Participants that have made Reserve Sharing Requests, which, as stated in Section F, applies to all Reserve Sharing Requests made within 60 minutes following the start of the Qualifying Event.

If (a) a Reserve Sharing Request is made more than four minutes following the start of the Qualifying Event, and (b) the NWPP Reserve Sharing Group's Reporting ACE does not recover from the Qualifying Event within the applicable Contingency Event Recovery Period, then for purposes of any potential compliance consequences associated with the Qualifying Event, the matter will be addressed in accordance with Sections 7.2, 7.3, 8, and 9 of the Agency Agreement.

A Participant that has made a Reserve Sharing Request may rely on Assistance Reserve for a maximum period of 60 minutes from the time of the Qualifying Event.

The Qualifying Event outlined in Attachment B part D, allows for a request to be made at any time during the declared EEA 3 instead of immediately upon declaration of the EEA 3. An Assistance Reserve Request made for an EEA 3 allows the Participant to receive Assistance Reserve for up to 60 minutes from the time of the initial request. Subsequent hours of an EEA 3 are not additional Qualifying Events. If a participant is out of a declared EEA 3 for more than one hour before another EEA 3 is declared that next EEA 3 declaration will be considered a new Qualifying Event.

If another Qualifying Event occurs, it is a separate event, and the Participant may make an additional request for Assistance Reserve.

E.4. Performance Metric

Deployment of Contingency Reserve by a Participant requesting Assistance Reserve will be measured through evaluation of the Participant's Pre-Reporting Contingency Event ACE through the following criteria:

- In the first fifteen-minute period after the disturbance occurs, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within nineteen minutes after the disturbance occurs and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.
- If the request is not made within the required 4-minute period after the start of the Qualifying Event, the entity will be deemed to have not performed to the requirements of the program.

E.5. Accounting for Energy; Transmission for Delivery

Any Participant that requests Assistance Reserve must complete a NWPP RSG Verification Form and must account for scheduled receipt and delivery of Assistance Reserve energy as "Contingency Reserve." Tagging of Energy with respect to deliveries of Assistance Reserve energy is implemented as described in Section K.1.c. of this document.

The delivery of Assistance Reserve is exempt from any costs or charges associated with transmission wheeling or losses. The Reserve Sharing Computer System builds in sufficient transmission capacity for delivering Assistance Reserve (see Section M). There may be incremental transmission usage between some Reserve Sharing Zones, but this usage is effectively limited in real-time up to the current System Operating Limit (SOL) of the transmission facilities making up the cut planes between Reserve Sharing Zones (subject to certain further limitations with respect to particular cut planes as described the *NWPP RSG Cut Planes and Derivation Limits* document). Participants in the NWPP Reserve Sharing Program recognize the regional benefits associated with the NWPP Reserve Sharing Program and have agreed to waive any rights to financial settlement for any transmission needed to deliver Assistance Reserve to other Participants.

E.6. Restoring Reserves

If a Participant uses any portion of its Contingency Reserve Obligation in response to a Qualifying Event (whether use is limited to Internal Reserve or requires additional Assistance Reserve), the Participant should take appropriate action to restore Contingency Reserve Available on its system (to at least the level of its Contingency Reserve Obligation) as promptly as practicable. A Participant may not take longer than 60 minutes (measured from the start of the Qualifying Event) to restore Contingency Reserve Available on its system to at least the level of its

Contingency Reserve Obligation.

F. OBLIGATION TO PROVIDE ASSISTANCE RESERVE

Each Participant is obligated to deliver Assistance Reserve up to the full amount of its Balancing Authority Area's Contingency Reserve Obligation (after deducting for any capacity that has been deployed to respond to any Qualifying Events) in response to any Reserve Sharing Request that has met the requirements in Section E.2 and is made within 60 minutes following the start of the Qualifying Event.

Deployment of Contingency Reserve by a Participant providing Assistance Reserves will be measured through evaluation of the Participant's Reporting ACE through the following criteria:

- In the first ten-minute period after the request for Assistance Reserve, or any increase thereof, is received, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within fifteen minutes of the request for Assistance Reserves and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.

If a Participant has deployed all or a portion of its Balancing Authority Area's Contingency Reserve Obligation to respond to a Reserve Sharing Request by another Participant and then, while the deployment is still in effect, experiences its own Qualifying Event, the responding Participant may deploy whatever portion of its Contingency Reserve Obligation is required to recover from its own Qualifying Event. If the conditions necessary to receive Assistance Reserve are satisfied, the Participant may also make a Reserve Sharing Request even if one or more other Participants' Reserve Sharing Requests remain in effect. If the NWPP Reserve Sharing Group experiences sequential Qualifying Events that require one or more responding Participants to deploy Assistance Reserve that was being provided to other Participants, the Reserve Sharing Computer System will recalculate the distribution of Assistance Reserve and allocate to remaining Participants any amount necessary to replace the deployed Assistance Reserve.

G. ELIGIBILITY FOR AND PARTICIPATION IN RESERVE SHARING PROGRAM

G.1. Eligibility to Participate in the NWPP Reserve Sharing Program

All Balancing Authorities that operate Balancing Authority Areas located within the Northwest Power Pool and that elect to become NWPP Agreement Signatories must participate in the NWPP Reserve Sharing Program and must become parties to the Agency Agreement.

G.2. Treatment of Third-Party Generation

Each Participating Balancing Authority must, in calculating its Contingency Reserve Obligation, include all generation that is within its metered boundaries and for which the Participating Balancing Authority has an obligation or has agreed to provide Contingency Reserve. The term "Qualifying Event" with respect to a Participating Balancing Authority applies to any generation (including Third-Party Generation) that has been included in that Participating Balancing Authority's calculation of its Contingency Reserve Obligation.

H. ROLES AND RESPONSIBILITIES

H.1. Participant Responsibilities

Participants are responsible for abiding by the NWPP Reserve Sharing Group rules specified in this document, together with any corresponding policies adopted by the RSG Committee. These include requirements to meet Contingency Reserve Obligations, to provide Assistance Reserve when requested by another Participant, and to settle for deliveries of Assistance Reserve energy as provided in Section K.
Participants must also provide and receive data for the NWPP Reserve Sharing Program in accordance with Section I for general operation of the NWPP Reserve Sharing Program and Section J for making and responding to requests for Assistance Reserve.

a. Notifications

Participants must notify the WPP Staff and the NWPP Reserve Sharing Group Committee whenever a substantive change to the Participant's Balancing Authority Area is planned to occur. This would include, at a minimum, a change in Balancing Authority Area footprint or boundary, transfer of load or generation with another Balancing Authority Area, or any change that could have an impact to the deliverability of contingency reserves or the MSSC within the Participant's zone. This notification should occur prior to any changes being made to allow adequate time for appropriate impact studies to be completed and Program Document or computer program modifications, as needed.

The Participating Balancing Authorities are responsible to provide planned system failover notifications that may have an impact to data being telemetered to the Reserve Sharing Computer System to WPP Staff via an email to nwpprsg@westernpowerpool.org.

b. Program Monitoring

In addition, the Participating Balancing Authorities are responsible to monitor the NWPP Reserve Sharing Group "heartbeat" (as explained in Section I.1.n). If any Participating Balancing Authority discovers the NWPP Reserve Sharing Group heartbeat is inactive for a period of 10 minutes they should contact an adjacent Participating Balancing Authority to confirm this is a system-wide problem and not just a problem with their system or communication link. If the problem is believed to be system-wide that Participating Balancing Authority will contact the WPP Staff.

If a Participating Balancing Authority's heartbeat appears to be inactive at the time it needs to make a Reserve Sharing Request, it should initiate the Reserve Sharing Request as described in Attachment E – *Backup Procedures for NWPP Reserve Sharing Program*.

It is all Participating Balancing Authorities' responsibility to inform all other Participating Balancing Authorities and the WPP Staff if they have discovered a problem. In addition, Participating Balancing Authority System Operators and RSG Committee Representatives can e-mail or call with any questions or issues. WPP Staff will respond as soon as possible.

NWPP Reserve Sharing Group Program Support Contact Information:

- For immediate response the on-call support number at 503.673.6744.
- In addition, for non-urgent issues, you may email "nwpprsg@westernpowerpool.org". WPP Staff will respond to after-hours emails the next business day during normal work hours.

H.2. WPP Staff Monitoring and Reporting Responsibilities

The WPP Staff is responsible for monitoring Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems related to Participant deficiencies or poor performance, for developing remedies and presenting proposed solutions, and for identifying and implementing any follow-up actions.

The WPP Staff is responsible for receiving NWPP RSG Verification Forms from Participants that have made Reserve Sharing Requests under the NWPP Reserve Sharing Program. The WPP Staff will perform analysis on each Reportable Balancing Contingency Event that the NWPP Reserve Sharing Group experiences with relationship to Participant's adherence to the Program Rules.

Subject to appropriate confidentiality and use restrictions (as determined by the WPP Staff), the WPP Staff may make available, to a Participant hosting implementation of an ACE Diversity Interchange arrangement, data related to the NWPP Reserve Sharing Program for the purpose of enabling the hosting Participant to harmonize the operation of the NWPP Reserve Sharing Program and the implementation of the ACE Diversity Interchange arrangement.

WPP Staff is responsible for monitoring and assisting in the implementation of the NWPP Reserve Sharing Program. While not staffed 24x7, WPP Staff will provide on-call 24x7 support as may be required. Although Participants are responsible for telemetering data to the Reserve Sharing Computer System as described in Sections I.1, and I.2, if WPP Staff notices missing information, WPP Staff will follow up with the affected Participant(s).

WPP Staff can review the status of each of the individual Participating Balancing Authority's data including heartbeats. If a WPP Staff member discovers a Participating Balancing Authority's heartbeat is inactive, he or she will follow up with the affected Participating Balancing Authority and document any findings by e-mail to all Participating Balancing Authorities.

H.3. RSG Committee Reporting Responsibilities

The RSG Committee is responsible for developing guidelines and arranging for periodic reports on the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and Contingency Reserve Available within the NWPP Reserve Sharing Group as a whole.

I. GENERAL DATA REQUIREMENTS

This section describes data responsibilities for Participants in the NWPP Reserve Sharing Program. Although in general all required data are relayed automatically to the Reserve Sharing Computer System, all Participants must also have the capability to enter data manually if communications between Participating Balancing Authorities and the Reserve Sharing Computer System are interrupted.

I.1. Data Telemetered from Participating Balancing Authorities to the Reserve Sharing Computer System

Each Participant must telemeter the following data to the Reserve Sharing Computer System for each of its Balancing Authority Areas within the Northwest Power Pool:

a. the portion of its Contingency Reserve Available that is WECC Operating Reserve - Spinning ($TotCSR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

b. total Contingency Reserve Available ($TotAvailCR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

c. its total Balancing Authority Area Load (LOAD), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

d. its total Balancing Authority Area Generation (GEN), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

e. any portion of its reported Contingency Reserve Available already in use ($UsedCR_{CA}$),

f. its Reporting ACE (ACE_{raw}), as calculated according to the NERC glossary of terms,

g. its Most Severe Single Contingency ($MSSC_{CA}$),

h. Scheduled Net Interchange values (NET_SCHED_INT), as used to calculate an equivalent ACE,

i. Actual Net Interchange values (NET_ACTUAL_INT), as used to calculate an equivalent ACE,

j. its Reserve Sharing Request dynamic schedule ($RSReq_{CA}$),

k. request for Reserve Sharing Status Indication ($RSReq_Confirmd_{CA}$)

No Request = Status Open

Assistance Requested = Status Closed,

l. reserve sharing response (RSResp),

m. indication (manually entered) of availability to provide Assistance Reserve (Participating Balancing Authorities not available to provide Assistance Reserve can still receive Assistance Reserve) (BA_Participate)

Cannot Provide Assistance Reserve = Status Open

Can Provide Assistance Reserve = Status Closed,

n. status of the communications links that enable it to participate in the NWPP Reserve Sharing Program on an automated basis, also known as its “heartbeat” (signaled by continuing changes to indicator data not to exceed 999,999, which the Reserve Sharing Computer System monitors at 10-second intervals; if there is no change to the data for a period of 60 seconds, the Participating Balancing Authority is presumed to be able to participate in the NWPP Reserve Sharing Program only through manual action; when the indicator data begin to change again, the Participating Balancing Authority is presumed to have regained the ability to participate in the NWPP Reserve Sharing Program through automated action) (BA_heart_beat), and

o. its frequency bias setting. (BA_FBS)

p. its meter error term (BA_Ime)

q. its ATEC term (BA_ATEC)

r. its ADI term if not included in Scheduled Net Interchange or Actual Net Interchange values above (BA_ADI)

I.2. Cut Planes

Explanatory note: As used in this Section I.2, the term "cut plane" is intended generally to describe an imaginary line separating two areas within a transmission system (or two different transmission systems) to enable the evaluation of flow of electrical energy on multiple lines connecting these two areas (or systems). The cut planes referred to below are sets of multiple lines connecting Reserve Sharing Zones.

Participants that are operators of the major transfer facilities must telemeter to the Reserve Sharing Computer System actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow for the cut planes, as identified in Attachment L, between Reserve Sharing Zones as described in the next Section I.3.e.

The RSG Committee maintains a separate document, *NWPP RSG Cut Planes and Derivation Limits*, that more fully details the major transfer facilities and any associated Participant derivation information, including applicable calculations for which the Participant that monitors that cut plane, address the evaluation of flow of electrical energy on multiple lines.

I.3 Functions of the Reserve Sharing Computer System

Except when communications links or the necessary computer capabilities are down, the Reserve Sharing Computer System performs the tasks listed below. WPP Staff is able to monitor the Reserve Sharing Computer System and receive all Participants' data described in Sections I.1 and I.2. If WPP Staff notices that there is missing information, WPP Staff will consult directly with any Participating Balancing Authorities for which information is missing to make any necessary corrections.

a. Determine the Most Severe Single Contingency for the NWPP as a whole ($MSSC_{NWPP}$).

b. Determine the aggregate Contingency Reserve Obligation for the NWPP as a whole ($TotCRO_{NWPP}$) to ensure that the Contingency Reserve Available within the NWPP Reserve Sharing Group is sufficient to cover the Contingency Reserve Obligation for the NWPP as a whole.

c. Determine the Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s), calculated in accordance with Attachment A.

d. Compute a pro rata allocation of any applicable adjustments to Contingency Reserve Obligations ($AdjCRO_MSSC_{CA}$ and $AdjCRO_ZONE_MSSC_{CA}$, which together are summed into $AdjCRO_{CA}$) for each Participant's Balancing Authority Area(s) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

e. In calculating any potential need to carry additional Contingency Reserve within a Reserve Sharing Zone, take into account transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on

the transmission facilities connecting that Reserve Sharing Zone to its adjacent Reserve Sharing Zone(s). With respect to the facilities linking the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone, this also reflects limits on ownership rights.

f. Maintain a pro rata allocation of the Reserve Sharing delivery dynamic schedule based upon each $TotCRO_{CA}$ for each Participant's Balancing Authority Area(s) relative to the $TotCRO_{NWPP}$.

g. Upon receipt of a Reserve Sharing Request dynamic schedule from a Participating Balancing Authority that is requesting Assistance Reserve, validate and activate the pro rata sharing signal to all other Participating Balancing Authorities.

h. Whenever Assistance Reserve is being delivered across facilities connecting two different Reserve Sharing Zones, continue to monitor actual flows ($ACTUAL_{Pathnn}$) in comparison to transfer limits ($LIMIT_{Pathnn}$) between the Reserve Sharing Zones, and, to the extent actual flows fall below transfer limits, allow deliveries to increase if needed to fully respond to the Reserve Sharing Request.

i. Maintain hourly integrated Reserve Sharing Request dynamic schedules from each Participating Balancing Authority.

j. Calculate a NWPP Reserve Sharing Group ACE (TOTACE_POOL) for entire NWPP Reserve Sharing Group.

k. Calculate a NWPP Reserve Sharing Group Reporting ACE for each Requesting Zone and Level 1 (or Level 2 for NCAL) Participants (ZONEACE_XXX – See Attachment C).

Each Participating Balancing Authority should consistently review the Contingency Reserve Obligation (CRO_{CA}) value transmitted to it by the Reserve Sharing Computer System to confirm the accuracy of the calculation and should promptly contact WPP Staff if it suspects there may be an error in the Reserve Sharing Computer System's calculation.

I.4. Data Telemetered from the Reserve Sharing Computer System to Participating Balancing Authorities

The Reserve Sharing Computer System makes available to each Participant the following telemetered data:

a. The Reserve Sharing Computer System's calculation of total Contingency Reserve Obligation ($TotCRO_{CA}$) for the Participant's Balancing Authority Area(s), as described in Attachment A. This includes, as applicable,

- calculation of base Contingency Reserve Obligation based on three percent of load and three percent of generation (CRO_{CA}),

- any adjustment to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group ($AdjCRO_MSSC_{CA}$),
- any adjustment to address shortages within a particular Reserve Sharing Zone ($AdjCRO_ZONE_MSSC_{CA}$), and
- combined adjustments to Contingency Reserve Obligation ($AdjCRO_{CA}$) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.
- total Contingency Reserve Obligation ($TotCRO_{CA}$) as adjusted to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

b. If the total Contingency Reserve Available within the NWPP Reserve Sharing Group ($TotAvailCR_{NWPP}$) is less than to total Contingency Reserve Obligation for the NWPP Reserve Sharing Group ($TotCRO_{NWPP}$), the NWPP Reserve Sharing Computer System calculates and telemeters necessary adjustments to total Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s) to reflect the shortfall in total Contingency Reserve Available within the NWPP Reserve Sharing Group ($AdjCRO_SHORT_{CA}$). Each Participant must carry this adjustment amount in addition to its $TotCRO_{CA}$.

c. If a Participant is in the penalty level 4 status, a flag (TBD) will be set by WPP Staff to communicate to the program and to the Participant that they are required to carry additional Contingency Reserves.

d. Reserve Sharing Delivery dynamic schedule (RSDel) for Participating Balancing Authority that is delivering Assistance Reserve:[1]

$RSDel_{CA(Level\ 1)} = RSReq_{CA} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 1)})$, limited to the portion of its Contingency Reserve Obligation ($TotCRO_{CA}$), if any, the Participating Balancing Authority is able to deliver at that time (after accounting for any portion of its $TotCRO_{CA}$ previously deployed)

Where,

$RSReq_{CA}$ £ MW_{LOSS} - $TotCRO_{CA}$

- If $S\ RSDel_{CA(Level\ 1)} < RSReq_{CA}$, then

[1] (All "$_{CA}$" designations in these formulas refer to the particular Participating Balancing Authority to which a given value applies. References to "Levels" are to the Levels related to the Reserve Sharing Zones, as identified in Attachment C.)

$RSReq_{Short} = RSReq_{CA} - S\ RSDel_{CA(Level\ 1)}$

and,

$RSDel_{CA(Level\ 2)} = RSReq_{Short} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 2)})$.

- If the amount of Assistance Reserve that can be delivered from the Participating Balancing Authorities at Level 2 is insufficient to meet whatever portion of the Reserve Sharing Request remains after deliveries from Participating Balancing Authorities at Level 1, the process is repeated as described above for Level 3, and, if applicable, Level 4 and Level 5.
- If there are multiple requests for Assistance Reserve, the $RSDel_{CA}$ would be calculated to reflect the sum of all amounts to be delivered as Assistance Reserve to requesting Participants, but the Reserve Sharing Computer System separately tracks the amounts to be delivered to each of the requesting Balancing Authorities (so that payment and return energy obligations can be properly determined).
- Requests for Assistance Reserve are not allowed to exceed the Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole.
- Transmission constraints are included the Reserve Sharing Computer System's calculation of how much Assistance Reserve can be delivered from each Level for each Reserve Sharing Zone, and so do not need to be separately computed and applied.

e. Delivery of Reserve Sharing Confirmation Flag ($RSDel_Confirmd_{CA}$),

No Request = Status Open

Assistance Requested = Status Closed

f. Reserve Sharing time remaining for the requesting Balancing Authority from the most recent request for Assistance Reserve (TimeLeft)

g. Number of active Reserve Sharing Requests (RSAct)

h. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$)

i. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$)

j. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$)

k. NWPP Reserve Sharing Group Reporting ACE (ACE_{NWPP})

l. Reportable Balancing Contingency Event (RpDist)

Where,

RpDist = the lesser of (a) 0.8 * $MSSC_{NWPP}$ or 500 MW

m. Total number of minutes remaining since the most recent request for the NWPP (RSTimRem)

n. The indication that the Reserve Sharing Computer System and associated communication links are operational is also known as the NWPP Reserve Sharing Group "heartbeat."

o. When activity on the Reserve Sharing Computer System is due to testing rather than power system conditions, this is indicated by a testing flag. WPP Staff will arrange for this flag to be set while testing is underway, which may include helping a Participating Balancing Authority test its system(s). (The NWPP Reserve Sharing Program is fully operational while testing is in progress and Reserve Sharing Requests may be made normally. If there is a Reserve Sharing Request during testing, the test will be terminated.)

p. The Reserve Sharing Computer System's calculation for each Reserve Sharing Zone as reflected in Attachment C,

- The MSSC ($MSSC_{zone}$)
- The total Contingency Reserve within the zone ($TOTCR_{zone}$),
- Calculation of the zonal Contingency Reserve Obligation based on the zonal Participant(s) three percent of load and three percent of generation ($TOTCRO_{zone}$),
- The total Contingency Reserve Available to the zone ($TOTCRA_{zone}$),

q. The Reserve Sharing Computer System's information or calculation for each cut plane between Reserve Sharing Zones as reflected in in Section I.2.

- The actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow
- The actual room ($ROOM_{PATHnn}$) and reserve ($RESERVE_{PATHnn}$) for each direction of flow

I.5. Informational Data Telemetered from the Reserve Sharing Computer System to the Reliability Coordinators

The Reserve Sharing Computer System telemeters to the Reliability Coordinators the following informational data:

a. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$),

b. The Reserve Sharing Group Reporting ACE (ACE_{NWPP}),

c. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$), and

d. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$).

e. Data for each of the Reserve Sharing Zones as follows:
   - The MSSC for the Reserve Sharing Zone,
   - The Contingency Reserve Obligation for the Reserve Sharing Zone, and
   - The Contingency Reserve Available for the Reserve Sharing Zone.

Attachment N is a correlation table of Participants, Reliability Coordinators, and Reserve Sharing Zones.

J. DATA REQUIREMENTS RELATED TO RESERVE SHARING REQUESTS

The general data requirements for Participants in the NWPP Reserve Sharing Program are described in Section I. The provisions below explain the steps for making and responding to Reserve Sharing Requests.

J.1. Requesting Participant

a. A Participant that has met the conditions to make a Reserve Sharing Request (as described in Section E.2) must calculate the amount of Assistance Reserve for which it is eligible, enter the deficient amount needed into a Reserve Sharing Request dynamic schedule, and send the request, at a zero-ramp span time, to the Reserve Sharing Computer System.

   Where,

   $RSReq_{CA}$ £ MW_{LOSS} – $TotCRO_{CA}$

   RqstRSSI = 1.

   At this point in time, the Participant's anticipated CR_{CA} should be zero if their CR_{CA} was equal to $TotCRO_{CA}$. If CR_{CA} was higher than $TotCRO_{CA}$, CR_{CA} should decrease by the amount shown as $UsedCR_{CA}$.

   $TotCRO_{CA} – UsedCR_{CA} \leq 0$

c. Requesting Participants are expected to restore the Contingency Reserve Available on their systems, to at least the level of their Contingency Reserve Obligations, as promptly as practicable, but in no event longer than 60 minutes from the start of the Qualifying Event.

d. As a safeguard, the Reserve Sharing Computer System will remove the Reserve Sharing Request dynamic schedule within 65 minutes following the Reserve Sharing Request.

   $RSReq_{CA}$ = 0, ten-minute ramp to zero beginning at 55 minutes after the request first started.

   RqstRSSI = 0

e. If during the request the Requesting Participant detects a Reserve Sharing Computer System failure, it should assume that the Responding Participants will continue to deliver reserves for the full 65 minutes as called for in J.1.d.

f. If a Participant makes a Reserve Sharing Request for an initial Qualifying Event and, before the end of the 60 minutes during which the Participant is allowed to rely on Assistance Reserve (as provided in Section E.3 of this document), experiences one or more additional Qualifying Events for which it wishes to request Assistance Reserve, the Participant may initiate additional Reserve Sharing Requests by (1) activating the additional Reserve Sharing Request toggle on the Reserve Sharing Computer System (which indicates that the requesting Participant has two or more active Reserve Sharing Requests), then (2) revising the deficient amount needed, as calculated in accordance with Section J.1.a above, to include the additional amount of Assistance Reserve required for the additional Qualifying Event(s). The activation of any additional Reserve Sharing Request will re-set the overall event timer to 65 minutes (the permitted 60-minute reliance period plus an additional five minutes to complete ramping). While the Reserve Sharing Computer System continues to run separate event timers for each Qualifying Event, Participants are able to see only the time remaining for a Participant's last-initiated Reserve Sharing Request, and not for any of its previously initiated Reserve Sharing Requests.

J.2. Responding Participants

a. Responding Participants should initiate a response to a Reserve Sharing Delivery dynamic schedule from the Reserve Sharing Computer System by including $RSDel_{CA}$ in their ACE equation shown below. A security check on the Reserve Sharing Request dynamic schedule includes a crosscheck such that Reserve Sharing Status Indication = 1. The sign of the $RSDel_{CA}$ is negative for Participating Balancing Authorities requesting Assistance Reserve. The sign of the $RSDel_{CA}$ is positive for Participating Balancing Authorities providing Assistance Reserve.

   Where,

   $ACE_{CA} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$

   NI_S = S(adjacent Balancing Authority schedules) + S(dynamic schedules) + $RSDel_{CA}$

Each responding Participant will maintain an internal timer equal to $TotTmRem_{NWPP}$ and continue to count down this timer to zero if the value from the Reserve Sharing Computer System fails to decrement (indicating probable loss of data link). Whenever a responding Participant is operating in an assumed disconnected mode, $RSDel_{CA}$ is internally frozen. When the internal count-down timer reaches zero, the responding Participant should set $RSDel_{CA}$ to zero.

K. SETTLEMENT

A Participant that receives Assistance Reserve energy must compensate all Participants that deliver Assistance Reserve energy financially.

Participants may mutually agree to an alternate procedure, provided the affected Participants can account for the transaction appropriately.

This section explains how the data used for settlement is developed and the process through which Participants complete financial settlement. Attachment D includes a settlement process chart as reference of this process.

K.1. Settlement Data

Each hour, whether or not there has been a Reserve Sharing Request, the Reserve Sharing Computer System will transmit the hour-ending integrated dynamic schedule quantities (MWh) to all Participating Balancing Authorities. These data will be referred to as "Settlement Data" and will include source/sink energy information without consideration of transmission "wheeling" through intervening systems. Settlement Data are rounded and used to develop adjacent Balancing Authority interchange schedules. Settlement Data will be used to construct the official reserve sharing energy matrix (the "Matrix").

a. Rounding

Settlement Data are rounded to whole integers to accommodate scheduling and accounting systems:

- All Settlement Data quantities less than 1 MWh will be rounded to 0 MWh (e.g., 0.7 yields 0 MWh). This practice will reduce nuisance scheduling of small quantities.

- For quantities equal to or greater than 1 MWh, conventional rounding practices will apply. Fractional quantities less than 0.5 will be rounded down (*e.g.*, 27.2 yields 27 MWh) and fractional quantities of 0.5 or greater will be rounded up (*e.g.*, 27.9 yields 28 MWh). After rounding, Settlement Data are compiled into the matrix.

b. Mapping of Energy Schedules

Energy schedules must be mapped to adjacent Balancing Authorities to allow proper energy accounting consistent with existing reliability standards and regional business practices. The Participants have agreed to a pre-defined set of tag templates to account for the transmission mapping for the deliveries of Assistance Reserve Energy. This mapping includes wheeling parties between nonadjacent Balancing Authorities, and as further explained in Section K.1.c below, serves as the basis to create after-the-fact tags.

c. Automatic Tagging and Tag Templates

The Participants' tag templates reflect the transmission mapping for the delivery of Assistance Reserve energy between Participating Balancing Authorities. The Northwest Power Pool Corporation has a contract with Open Access Technology International, Inc. (OATI) to produce after-the-fact energy schedule tags for all deliveries of Assistance Reserve energy. These tags are provided to the Participants and the WECC Western Interchange Tool (WIT).

The WPP Staff is responsible for assisting with the maintenance of these tag templates used by OATI, and keeping them up-to-date in accordance with requests made by Participating Balancing Authorities. Attachment F describes the NWPP Reserve Sharing Group's procedures for revising the transmission mapping as reflected in the tag templates.

The Participants' tag templates are not publicly available and are only accessible to the RSG Representatives, their designated RSG Alternate Representatives and tagging personnel. The designated representatives may access and download the most current version of *NWPP RSG Tagging Templates.xls* on the Western Power Pool website (www.westernpowerpool.org) in the Reserve Sharing Group's Documents.

K.2. Financial Settlement

The NWPP Reserve Sharing Group utilizes the Intercontinental Exchange (ICE) day-ahead peak and off-peak index prices at the Mid-Columbia (Mid-C) and Palo Verde (PV) trading hubs, for the calculation of the settlement price as noted in subsection (a.) below.

A Participant will be financially reimbursed for providing Assistance Reserve energy.

For purposes of the NWPP Reserve Sharing Program, the "Settlement Price" for peak hours will be the average of the ICE day-ahead peak index prices for the Mid-C and PV trading hubs. The "Settlement Price" for off-peak hours will be the average of the ICE day-ahead off-peak index prices for the Mid-C and PV trading hubs, *provided, however*, that (a) if ICE does not publish a Day-Ahead Price for a relevant operating day or Request Hour, then the Settlement Price shall be the average of the other Day-Head Price for the Request Hour and (b) in no event will the Settlement

Price ($/MWh) be less than zero or greater than the WECC Soft Price Cap in accordance with regulations and orders of the Federal Energy Regulatory Commission (FERC).

Examples of settlement for 10 MWh of dispatched energy:

Example 1:
Index prices: Mid-C $50, PV $75
Calculation: ($50+$75)/2 = $62.50 settlement price x 10MWh = $625

Example 2:
Index prices: Mid-C $50, PV-No Trade.
Calculation: $50+ (excluded) = $50 settlement price x 10MWh = $500

Example 3:
Index prices: Mid-C $-20 (below price cap), PV $5,
Calculation: ($0 + $5)/2 = $2.50 Settlement Price x 10MWh = $25

Example 4:
Index prices: Mid-C $1035 (above WECC Soft Energy Price Cap), PV $750,
Calculation: ($1,000 + $750)/2 = $875*10MWh = $8,750

With respect to FERC-jurisdictional entities, the Settlement Price will be set forth in the Participant's individual tariff on file with and approved by FERC. In the event that the Settlement Price set forth in a. above is amended, such amended Settlement Price will not be effective until all FERC-jurisdictional entities have approved amended tariffs.

During the RSG Committee's third quarter meeting the RSG Committee (or a work group or task force appointed by the RSG Committee) will review the definition of "Settlement Price," to ensure the selected trading hubs and applicable day-ahead peak and off-peak index price continue to represent a fair value of energy within the NWPP Reserve Sharing Group footprint. The RSG Committee may elect to either maintain the current definition of "Settlement Price" or propose a modified definition to be considered for approval at the next meeting of the RSG Committee. The effective date of any modification to the definition of "Settlement Price" will be coordinated to allow Participants with applicable tariffs filed with FERC to make any necessary filings with FERC.

Unless the affected Participants have agreed otherwise, financial settlements will occur under the responding Participant's normal monthly billing cycle.

WPP Staff will be responsible for determining and posting Settlement Prices, calculated as described in subsection (a) above of this Section K.3, in accordance with the following procedures:

a. WPP Staff will use the day-ahead peak and off-peak prices posted by ICE at the end of each trading day to programmatically calculate and post the Settlement Price for all hours of the days for which prices were published (operating days).

b. In the first three (U.S.) business days following the first (U.S.) business day of each month (referred to in these procedures as the "lock down date"), WPP Staff may confer with designated Participants for assistance in validating the applicable prices posted by ICE for the preceding month and the computation of the Settlement Prices as necessary.

c. By the end of the third (U.S.) business day following the lock-down date, WPP Staff will post finalized Settlement Prices for all hours of the preceding month, computed as described in this subsection (e).

d. If, as of the lock-down date, information needed to compute one or more Settlement Prices has not yet been posted by ICE, WPP Staff will compute and post Settlement Prices for those applicable dates and hours within three (U.S.) business days following the date on which the necessary information is first posted by ICE.

e. Settlement Prices that have been posted by WPP Staff in accordance with the procedures set forth above will not be subject to further adjustment, except by agreement of all affected Participants.

L. INTERNAL NWPP RESERVE SHARING GROUP REPORTING

L.1 Obligation to Submit a NWPP RSG Verification Form

A Participant must, within two (U.S.) business days following the triggering event, prepare and submit to the WPP Staff a completed NWPP RSG Verification Form whenever any one of four conditions described below occurs:

a. The Participant makes a Reserve Sharing Request under the NWPP Reserve Sharing Program (including use of backup procedures specified in Section N if the automated process fails).

b. The Participant or the NWPP Reserve Sharing Group has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (i) 500 MW, or (ii) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

c. The WPP Staff contacts the Participant requesting a NWPP RSG Verification Form because the Participant has ownership or contractual rights in a jointly owned facility and the WPP Staff is following up with the Participant as described in Section L.2.

d. The Participant has experienced a Reliability Coordinator declared Energy Emergency Alert (as described in NERC Standard EOP-011 or successor standard).

NWPP RSG Verification Forms are available on the WPP Website. The Participants will transmit completed forms via e-mail to nwpprsg@westernpowerpool.org. The Western Power Pool Corporation, in its capacity as agent for the NWPP Reserve Sharing Group, may request additional data and information as may be required and is responsible for submitting periodic reports to the WECC and NERC in accordance with their requirements.

L.2 Reporting Balancing Authority Obligation to Notify WPP Staff

A Participant that is the Reporting/Operating Balancing Authority (as specified in Attachment K) for a jointly owned facility must, as soon as feasible, but in any case within two (U.S.) business days following the triggering event, provide written notice to the WPP Staff (which may be by electronic mail) whenever the jointly owned facility for which it is the Reporting/Operating Balancing Authority has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (a) 500 MW, or (b) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

The WPP Staff will promptly follow up with all other Participants that have ownership or contractual rights in the jointly owned facility to request that those Participants submit completed NWPP RSG Verification Forms.

M. RESERVE SHARING ZONES

The NWPP Reserve Sharing Program takes into account the effect constrained transmission facilities can have on the ability of Participants to deliver Assistance Reserve energy to one another. When a Participating Balancing Authority (or a group of Participating Balancing Authorities) is separated from remaining Participants by constrained transmission facilities, the effect of the constraint is reflected in the establishment of Reserve Sharing Zones. Attachment C to this document identifies the Reserve Sharing Zones for the NWPP Reserve Sharing Program, together with the sequence (levels) through which Assistance Reserve is deployed for each Reserve Sharing Zone.

The Long-Term Zonal MSSC Limits account for limitations, as determined by the Participant Balancing Authority(ies) of each zone as identified in Attachment K.1.

Proposed system changes that will result in an increase to a Long-Term Zonal MSSC as identified in Attachment K, must be approved by the Balancing Authorities of the impacted zone within 120 days of system change being identified.

In addition, any proposed change to the NWPP Reserve Sharing Group Long-Term MSSC Limit as identified in Attachment K, must be approved by the NWPP Reserve Sharing Group Committee.

N. BACKUP PROCEDURES

Reserve Sharing Requests and delivery of Assistance Reserve energy are normally implemented through the Reserve Sharing Computer System. When a Participant cannot access the Reserve Sharing Computer System (or the system is inoperable), the Participant should use the manual backup procedures as reflected in Attachment D's respective process chart and described in Attachment E and to make any Reserve Sharing Requests. In these circumstances, a responding Participant is obligated to provide Assistance Reserve only up to the amount of its available transmission capacity or its Contingency Reserve Obligation, whichever is smaller. The settlement process for delivery of Assistance Reserve energy using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

O. PROCEDURES FOR ADDRESSING ISSUES AFFECTING RESERVE SHARING PROGRAM WHEN AGENCY AGREEMENT PROCESS IS INSUFFICIENT

To facilitate reporting and compliance activities related to NERC or WECC reliability standards that may affect the NWPP Reserve Sharing Program, the Participating Balancing Authorities have entered into the Agency Agreement. All Participating Balancing Authorities, as well as the Northwest Power Pool Corporation, are parties to the Agency Agreement. The Agency Agreement contains provisions that enable Participating Balancing Authorities to call meetings on specified prior notice and make decisions about matters concerning the Agency Agreement or the NWPP Reserve Sharing Program. Any meeting or vote under the Agency Agreement requires at least 10 days' prior notice.

If an urgent matter related to NWPP Reserve Sharing Program arises, and the WPP Staff determines in good faith that either (1) there is insufficient time to address the matter through the procedures in the Agency Agreement or (2) the matter is outside the scope of the Agency Agreement, the WPP Staff will:

- make commercially reasonable efforts to promptly deliver electronic notice of the matter to each designated contact for notice under the Agency Agreement;
- convene a meeting by telephone conference (with the option of in-person attendance at the offices of the Northwest Power Pool Corporation if feasible) of all available Participating Balancing Authorities, giving as much advance notice and facilitating attendance of as many Participating Balancing Authorities as feasible in view of any need for prompt action;

- seek input from the Participating Balancing Authorities as to what action should be taken, and, if appropriate in the judgment of the WPP Staff or requested by any Participating Balancing Authority, take a vote of the Participating Balancing Authorities (on the basis that a vote of not less than two-thirds of the Participating Balancing Authorities present at the time the vote is taken will be necessary to approve an action or decision); and
- make commercially reasonable efforts to take follow-up action consistent with the input received or results of any vote taken in accordance with this Section O.

No vote of the Participating Balancing Authorities conducted in accordance with this Section O may have the effect of (a) amending this NWPP Reserve Sharing Program documentation, (b) amending the Agency Agreement, (c) authorizing settlement of any NERC or WECC compliance-related matter that will or could cause any party to incur violation(s), monetary penalties or other legal liability (unless the party or parties incurring violation(s), monetary penalties or legal liability have given their prior written consent); or (d) restricting the ability of any party to independently exercise whatever legal or procedural rights it may have to challenge action taken by or petition an Enforcement Authority (as that term is defined in the Agency Agreement) in connection with any NERC or WECC compliance-related matter.

P. PENALTIES FOR NON-PERFORMANCE (Effective July 1, 2024)

P.1 Grading

Events will be assessed shortly after they occur to provide feedback to the involved BAAs. Official grading for events will occur once that entity reaches the evaluation threshold. An entity may fail per the defined performance metrics and receive a score greater than 0%.

The evaluation threshold is any calendar quarter that the BAA participated in ten or more events. If an entity participates in fewer than ten events in any calendar quarter, that quarter will be considered a null quarter, and the events roll over to the next calendar quarter. Once ten events are accumulated, those events and any others during that quarter, will be evaluated and scored.

Each Assistance Reserve request and response will be evaluated and scored as follows:

For a Participant requesting Assistance Reserve:

- 50% for initial ACE Recovery in the first fifteen-minute period after the disturbance, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of their individual BAA's L10 value (as published by NERC) in the first nineteen clock-minutes after the disturbance with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

If the request is not made within the required 4-minute period after the start of the Qualifying Event, the score will then be reduced by 10% for each minute (or portion thereof) beyond the 4-minute period the request is delayed. The minimum score a BAA may have is 0%.

For a Participant providing Assistance Reserve:

- 50% for initial ACE recovery in the first ten-minute period after the request for Assistance Reserve, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of the individual BAA's L_{10} value (as published by NERC) in the first fifteen clock-minutes after the request for Assistance Reserve with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

All events for the quarter will be individually scored and averaged together and rounded to the nearest 0.1%, to provide a total score for the quarter. If a BAA receives a score of less than 95%, they will be determined to have failed the quarter. These scores will be reported to the RSG Committee at each meeting. If the BAA does not have any events for a quarter, that quarter will be considered a null quarter and not count as a "Pass" or a "Fail".

P.2 Edge Case Events Review and Final Determination

All RSG events will be reviewed by WPP Staff. Events that are found to have characteristics making them more difficult to respond to (ex. requests where the value is changing during the analysis period or coming in and out) will be flagged for further review. Any of these events where it is later determined that there is no impact to any member's quarterly grade (Pass/Fail) will be removed from the overall calculation. Any events with an impact will be brought to the Reserve Sharing Group Committee for final determination.

If a BAA believes that an event should be removed from consideration, they may present their case to the RSG Committee during a committee meeting. The committee will then make a determination and the quarterly score will be recalculated as necessary.

P.3 Penalties

Penalties will be assessed based on how many quarters a BAA has failed. All BAA's begin at Level 0 and increase one level from their current level with a failed quarter (ex. Q1). Penalties will be analyzed in the following quarter (ex. Q2) and any level changes implemented at 0600 pacific prevailing time the first NERC scheduling day of the quarter after that (ex. Q3). For example: Q1 will be analyzed in Q2 and any level changes implemented in Q3. Decreasing levels and null quarters are addressed in section P.4.

The penalty levels are:

Level 1:

- An official letter to the Participant RSG Representative(s) notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- The Participant RSG Representative(s) will designate a Company Executive to be notified if Level 2 is reached

Level 2:

- An official letter to the designated Company Executive notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 3:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA will be required to carry additional Contingency Reserves with an additional failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 4:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA is now required to carry additional Contingency Reserves
- The BAA will be required to carry additional reserves and be limited on the events that qualify for requesting Assistance Reserves the for one Quarter.
    - The BAA will be obligated to carry the lesser of their MSSC or 150% of their regularly calculated CRO
    - The BAA will be allowed to call on Assistance Reserve only if they experience a loss greater than their increased obligation
    - During this quarter, the BAA must still respond to requests for Assistance Reserves
    - The BAA must update their EMS or other impacted IT/OT applications to reflect these changes
    - Meet all financial obligations associated with RSG membership

- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- While in this level, an additional failed quarter will result in that BAA(s) triggering a vote to be removed from NWPP Reserve Sharing Group by the membership.

Level 0:

- An official letter to the Participant RSG Representative(s) notifying them of the return to Level 0 Operations
- Normal Operations – no restrictions

P.4 Reset

Each quarter a BAA passes will reduce the penalty level under which they are operating. A "null quarter" will keep the BAA at the level they were at for the previous quarter unless the BAA was at Level 4 in which case the BAA would go to Level 3 until they have passed two consecutive quarters excluding null quarters.

ATTACHMENTS

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zones and Levels

Attachment D – NWPP Process Charts

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Reserve Tagging Change Process

Attachment G – Backup Process for After-the-Fact Reserve Sharing Tags

Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

Attachment A

Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

1. Calculation of Participating Balancing Authority Contingency Reserve Obligation

The NWPP Reserve Sharing Group has determined that the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be calculated as set forth below. The measure of the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be based on real-time measurements of load and generation, which, for compliance purposes, will be used to calculate integrated hourly averages. These integrated hourly averages will be compared to hourly averages of Contingency Reserve Available (also based on real-time measurements) to determine whether the NWPP Reserve Sharing Group's Contingency Reserve Available was sufficient to meet the requirements of BAL-002. The amount of Contingency Reserve Available within the NWPP Reserve Sharing Group for each clock hour must be equal to or greater than the NWPP Reserve Sharing Group's Contingency Reserve Obligation during that same clock hour.

As described in detail in Section 1 of this Attachment A and reflected in Attachment D's process chart for Calculation of CRO, the Reserve Sharing Computer System uses a four-step process to determine the Contingency Reserve Obligation a Participating Balancing Authority is required to meet for its Balancing Authority Area(s) under normal circumstances, using real-time measurements as described above. The Reserve Sharing Computer System completes the calculations necessary for this process (with updated real-time measurements) every data scan cycle (that is, no less frequently than every six seconds).

These calculation processes can be summarized as follows:

First, the Reserve Sharing Computer System calculates three percent of load plus three percent of generation. Next, the Reserve Sharing Computer System sums of all Participants' Contingency Reserve calculations to see whether this calculated sum is at least equal to the Most Severe Single Contingency for the NWPP Reserve Sharing Group. If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to cover the NWPP Reserve Sharing Group's Most Severe Single Contingency and determines the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s) as adjusted for the NWPP Reserve Sharing Group's Most Severe Single Contingency.

The third step calculates the amount of any additional Contingency Reserve that may be needed in a Reserve Sharing Zone to cover the Most Severe Single Contingency within that Reserve

Sharing Zone and determines each the Total Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), reflecting both applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and any adjustments necessary to address the Most Severe Single Contingency within a Reserve Sharing Zone.

The fourth step checks to make sure the aggregate amount of Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to Contingency Reserve Obligation of the NWPP Reserve Sharing Group according to the requirements of BAL-002 (both the WECC and the NERC versions). If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to fully comply with the Contingency Reserve requirements of BAL-002. Each Participating Balancing Authority must add this adjustment amount to its total Contingency Reserve Obligations and stand ready to deploy this adjusted Contingency Reserve Obligation (excluding amounts already deployed to respond to Qualifying Events) at all times for use as Internal Reserve and Assistance Reserve.

Section 4 of this Attachment sets out the process a Participating Balancing Authority should follow to determine its Contingency Reserve Obligation(s) when communication links between the Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable.

Set forth below are explanations and formulas for each step in the process to determine the total amount of Contingency Reserve a Participating Balancing Authority is required to carry.[2] For any Participant that has more than one Balancing Authority Area within the Northwest Power Pool, the calculations below are done separately for each of its Balancing Authority Areas.

a. <u>Step One – Calculation of Participating Balancing Authority Base Contingency Reserve Obligation</u>:

   The base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), or "CRO_{CA}" (before the adjustments described in the remainder of Section 1 of this Attachment A), is the sum of (i) three percent of the Load (as defined below) for the Participant's Balancing Authority Area(s), plus (ii) three percent of the Generation (as defined below) for the Participant's Balancing Authority Area(s).

   $$\mathbf{CRO}_{CA} = (0.03 \times \text{Generation}) + (0.03 \times \text{Load}),$$

[2] For consistency with formulas used in the Reserve Sharing Computer System, individual Participating Balancing Authority obligations are designated by the subscript "$_{CA}$." This is because the formulas in the Reserve Sharing Computer System were established when the function roughly corresponding to a Balancing Authority was referred to as a control area.

Where,

- **CRO_{CA}** = base Contingency Reserve Obligation
- **Generation** = BAA Net Generation - Designated Dynamically Scheduled Exports + Designated Dynamically Scheduled Imports [*see* Note 1]
- **Load** = BAA Net Generation - Actual Net Interchange [*see* Notes 2 and 3]
- **BAA Net Generation** = the sum of Net Generation for all generating units (whether measured by individual units or at the plant level or both) inside the Balancing Authority Area
- **Net Generation** (whether for an individual generating unit or a generating plant) = the greater of (a) the gross metered generation minus station service load, or (b) zero
- **Actual Net Interchange (NI_A)** has the meaning given to this term in the NERC Glossary
- **Scheduled Net Interchange (NI_S)** has the meaning given to this term in the NERC Glossary
- **Designated Dynamically Scheduled Exports =** all Dynamically Scheduled exports for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Designated Dynamically Scheduled Imports** for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Dynamically Scheduled** corresponds to the term "Dynamic Schedule," as defined in the NERC Glossary

Note 1: All generation within the Balancing Authority Area's or the NWPP Reserve Sharing Group's metered boundaries should be included in this calculation, with the only exception being generation expressly permitted to be excluded by the terms of BAL-002-WECC-3 (or comparable standards in jurisdictions outside the United States). Generation within a Balancing Authority Area by Pseudo-Tie (as defined in the NERC Glossary) is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its generation calculation.

Note 2: Generation within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation.

Note 3: Load within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation. Load within a Balancing Authority Area by Pseudo-Tie is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its load calculation by virtue of its inclusion in the Actual Net Interchange equation.

Note 4: This term captures net generation responsibility transferred, reflecting that Dynamically Scheduled generation exports can be subtracted from the exporting Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise), and Dynamically Scheduled generation imports should be added to the importing Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise).

b. Step Two – Check for Deficiency Related to Most Severe Single Contingency for the NWPP:

Once the Participating Balancing Authorities' base Contingency Reserve Obligations have been calculated, the second step in the process is to check for any potential deficiency, should the Most Severe Single Contingency for the NWPP exceed the sum of the Participating Balancing Authorities' Contingency Reserve Obligations as calculated in step one.

The NWPP's Most Severe Single Contingency is compared to the sum of all Participating Balancing Authorities' base Contingency Reserve Obligations. If the Most Severe Single Contingency is greater, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's base Contingency Reserve Obligation, as calculated in step one. This results in an upward adjustment to the base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this step are as follows:

If $S\ CRO_{CA} < MSSC_{NWPP}$, then

$$CRO_SHORT_{NWPP} = MSSC_{NWPP} - S\ CRO_{CA}$$

and

$$AdjCRO_MSSC_{CA} = CRO_SHORT_{NWPP} * CRO_{CA} / S\ CRO_{CA}$$

Where,

$S\ CRO_{CA}$ = sum of all Participating Balancing Authorities' base Contingency Reserve Obligations, as calculated through step one;

$MSSC_{NWPP}$ = the Most Severe Single Contingency for the NWPP Reserve Sharing Group, determined in accordance with the Typical Planning MSSC in real time table set forth in Attachment K;

CRO_SHORT_{NWPP} = the amount by which the Most Severe Single Contingency for the NWPP exceeds the sum of the Participating Balancing Authorities' base Contingency Reserve Obligations;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in step one;

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

$MSSC_{NWPP}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{NWPP}$ increases or decreases by one MW or more.

c. <u>Step Three – Check for Deficiency Related to Most Severe Single Contingency for a Reserve Sharing Zone and Sum of Adjustments</u>:

The third step in the process is to check for any potential deficiency within a Reserve Sharing Zone if the Zone's Most Severe Single Contingency exceeds the sum of (i) the Contingency Reserve Obligation for the Zone's Participating Balancing Authorities and (ii) the amount of Contingency Reserve that can be imported from adjacent Reserve Sharing Zones. This Zone adjustment is then summed with the adjustment from step two and added to the Participant's base Contingency Reserve Obligation to give Total Contingency Reserve Obligation.

The Reserve Sharing Computer System continuously monitors transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on transmission facilities connecting Reserve Sharing Zones.

If, after accounting for Contingency Reserve Obligation that can be delivered from adjacent Reserve Sharing Zones, the combined Contingency Reserve Obligations within the Zone is less than the Zone's Most Severe Single Contingency, this shortfall is allocated among the Zone's Participating Balancing Authorities in proportion to their relative shares of the aggregate Contingency Reserve Obligations (as calculated through steps one and two) for the Reserve Sharing Zone.

The formulas for adjusting Contingency Reserve Obligations, if necessary, for the Most Severe Single Contingency for a Reserve Sharing Zone are as follows:

If $S\ (CRO_{CA} + AdjCRO_MSSC_{CA}) + ASDEL_{ZONE} < MSSC_{ZONE}$, then

$$CRO_SHORT_{ZONE} = MSSC_{ZONE} - (S\ (CRO_{CA} + AdjCRO_MSSC_{CA}) + ASDEL_{ZONE})$$

and

$$AdjCRO_ZONE_MSSC_{CA} = CRO_SHORT_{ZONE} * (CRO_{CA} + AdjCRO_MSSC_{CA}) / S\ (CRO_{CA} + AdjCRO_MSSC_{CA})$$

and

$$AdjCRO_{CA} = AdjCRO_MSSC_{CA} + AdjCRO_ZONE_MSSC_{CA}$$

and

$$TotCRO_{CA} = CRO_{CA} + AdjCRO_{CA}$$

Where,

$S\ CRO_MSSC_{CA}$ = the sum of Contingency Reserve Obligations for all Participating Balancing Authorities in the Reserve Sharing Zone (as calculated through steps one and two);

CRO_MSSC_{CA} = the Contingency Reserve Obligation for a Participating Balancing Authority in the Reserve Sharing Zone, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$ASDEL_{ZONE}$ = the amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones, after accounting for relevant transfer limits, actual flows, and if applicable, scheduled flows on transmission facilities connecting Reserve Sharing Zones;

$MSSC_{ZONE}$ = the Most Severe Single Contingency for the Reserve Sharing Zone;

CRO_SHORT_{ZONE} = the amount by which the Most Severe Single Contingency for the Reserve Sharing Zone exceeds the sum of (i) the aggregate Contingency Reserve Available of the Participating Balancing Authorities in the Reserve Sharing Zone (S CRO_MSSC_{ZONE}), plus (ii) amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones ($ASDEL_{Lim}$);

CRO_{CA} = the Participating Balancing Authority's Contingency Reserve Obligation;

$AdjCRO_ZONE_MSSC_{CA}$ = the additional amount of Contingency Reserve a Participating Balancing Authority needs to carry to reflect the Most Severe Single Contingency for the Reserve Sharing Zone;

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$AdjCRO_{CA}$ = the total adjustment amounts to be added to a Participant's base Contingency Reserve Obligation to reflect any applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and the Most Severe Single Contingency for a Reserve Sharing Zone; and

$TotCRO_{CA}$ = the Participating Balancing Authority's Contingency Reserve Obligation as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for its Reserve Sharing Zone.

$MSSC_{ZONE}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{ZONE}$ increases or decreases by one MW or more.

d. Step Four – Calculation of Aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and Check for NWPP Reserve Sharing Group Shortfall:

The fourth step in the process calculates the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and makes sure the total Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group.

The aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group is calculated by summing the total Contingency Reserve Obligations (as calculated in steps one through three) for all Participants' Balancing Authority Areas.

The formula for this step is as follows:

$$TotCRO_{NWPP} = S\ TotCRO_{CA}$$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group; and

$S\ TotCRO_{CA}$ = the sum of the total Contingency Reserve Obligations of all Participating Balancing Authorities, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for applicable Reserve Sharing Zones.

If the Contingency Reserve Available within the NWPP Reserve Sharing Group is less than the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's Contingency Reserve Obligation (without factoring in adjustments for shortfalls within a Reserve

Sharing Zone). This results in an upward adjustment to the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this final check are as follows:

If $TotAvailCR_{NWPP} < TotCRO_{NWPP}$, then

$TotCRO_SHORT_{NWPP} = TotCRO_{NWPP} - TotAvailCR_{NWPP}$

and

$AdjCRO_SHORT_{CA} = (TotCRO_SHORT_{NWPP} * (CRO_{CA} + AdjCRO_MSSC_{CA}) / S (CRO_{CA} + AdjCRO_MSSC_{CA}))$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group;

$TotAvailCR_{NWPP}$ = the total amount of Contingency Reserve Available in the NWPP Reserve Sharing Group;

$TotCRO_SHORT_{NWPP}$ = the amount by which the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group exceeds the total Contingency Reserve Available;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in steps one;

$AdjCRO_SHORT_{CA}$ = the adjustment to the Participating Balancing Authority's Contingency Reserve Obligation to reflect the shortfall in total Contingency Reserve Available; and

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

Each Participant must add the adjustment amount ($AdjCRO_SHORT_{CA}$) to the total Contingency Reserve Obligation for its Balancing Authority Area(s) as calculated in step three ($TotCRO_{CA}$) and stand ready to deploy the combined amount of Contingency Reserve Available (excluding amounts already deployed to respond to a Qualifying Event) at all times for use as Internal Reserve and Assistance Reserve.

The NWPP Reserve Sharing Group will experience a shortfall only if one or more Participants have not fully met their Contingency Reserve Obligations.

2. Permitted Amounts and Types of WECC Operating Reserve - Supplemental

A Participating Balancing Authority's Contingency Reserve Obligation(s) may be met with WECC Operating Reserve - Supplemental, provided that any WECC Operating Reserve - Supplemental applied to a Participating Balancing Authority's Contingency Reserve Obligation can be made fully effective within 10 minutes.

Permitted Sources of WECC Operating Reserve - Supplemental

A Participating Balancing Authority is permitted to use WECC Operating Reserve - Supplemental to meet a portion of its Contingency Reserve Obligation(s) calculated in accordance with Section 1 of this Attachment A, the following may be used as sources of WECC Operating Reserve - Supplemental:

1. WECC Operating Reserve - Spinning,
2. WECC Operating Reserve - Supplemental,
3. Interchange Transactions designated by the Source Balancing Authority as WECC Operating Reserve - Supplemental,
4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service,
5. A resource, other than generation or load, that can provide energy or reduce energy consumption,
6. Load, including demand response resources, demand-side management resources, direct control load management, interruptible load or interruptible demand, or any other load made available for curtailment by the Participating Balancing Authority or the NWPP Reserve Sharing Group via contract or agreement, and

7. All other load, not identified in the foregoing items, once a Reliability Coordinator for the Northwest Power Pool has declared an energy emergency alert signifying that interruption of Firm Demand is imminent or in progress.

3. Participating Balancing Authority Calculation of Contingency Reserve Obligation(s) When Communications with Reserve Sharing Computer System Are Disrupted

During periods when communication links between a Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable, responsibility for calculating Contingency Reserve Obligations shifts to the Participating Balancing Authority. Any Participating Balancing Authority that is unable to access the Reserve Sharing Computer System's calculation of its Contingency Reserve Obligations should use good-faith estimates of the inputs needed to determine its Contingency Reserve Obligation, based on the last available input data known to be valid, and apply as many of the steps described in Section 1 of this Attachment A as it can, consistent with good utility practice. The Participating Balancing Authority should continue this process, adjusting as appropriate for relevant changes to system conditions, until availability of and communications with the Reserve Sharing Computer System are restored.

Attachment B

Qualifying Events

A "Qualifying Event" is any single event described in subsections (A), (B), (C), or (D) below, or any series of such otherwise single events, with each separated from the next by one minute or less. Any capitalized term used below that is not defined within this document has the meaning given to it in the NERC Glossary. This Attachment B may be modified from time to time by action of the RSG Committee.

(A) Sudden Loss of Generation

a. due to
    i. unit tripping (*see note 1 below), or*
    ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
    iii. sudden unplanned outage of transmission Facility;
b. and, that causes an unexpected change to the responsible entity's ACE (*see note 2 below*)

(B) Sudden Loss of an Import

a. due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. (*See note 3 below*).

(C) Sudden Restoration of Demand

a. that was used as a resource that causes an unexpected change to the responsible entity's ACE

(D) Energy Emergency Alert

a. where a Participating Balancing Authority's inability to meet Firm Demand such that the Participating Balancing Authority has requested its Reliability Coordinator to declare, and the Reliability Coordinator has declared an Energy Emergency Alert 3 (as described in NERC Standard EOP-011 or a successor standard) the Participant:
    i. May utilize its CRO to serve Firm Demand while the Participant is in an EEA 3;

ii. Must keep the RSG Computer System current with any portion of its Contingency Reserve Available already in use (UsedCR_{CA});

iii. Should reach out to neighboring BA's to verify no energy is available;

iv. Should reach out to cut-plane monitors for limit verification of any cut-planes with constraints impacting the BA's ability to receive Assistance Reserves;

v. May request Assistance Reserve through the NWPP Reserve Sharing Program for up to 60 minutes to prevent shedding Firm Demand, not to restore their Contingency Reserves.

1. Once the timeframe above has been depleted, then the Participant may continue to utilize its CRO to server Firm Demand. The Participant may need to shed Firm Demand to maintain Reporting ACE until the Participant is no longer in an EEA 3.

Note 1:

For purposes of this Attachment B, the term "unit tripping" means:

(1) the automatic operation of a device or capability designed to protect a power-producing resource from damage, or

(2) the unexpected failure of a power-producing resource to maintain, increase, or remain available due to equipment failure, or

(3) the unexpected failure of a power-producing resource to start (a) due to equipment failure, and (b) not associated with the failure to procure fuel,

which, in all cases, results in loss of MW output serving (or needed to serve) one or more Participants' Demand obligations.

Note 2:

The events described in Note 1 are Qualifying Events even when they do not result in an immediate change to the responsible entity's ACE.

Note 3:

Given typical operating practices followed in the Western Interconnection, the loss of an import would generally be expected to result in a corresponding adjustment to generation.

Attachment C

Reserve Sharing Zones and Assistance Reserve Responder Levels

Each Reserve Sharing Zone, as identified in the table below, has one or more Balancing Authority Participants.

Zones	Balancing Authority Participants
Alberta (AB)	AESO
Arizona -Nevada (AZNV)	AZPS, BNBA, DEAA, GRID, SRP, TEPC, WALC & NEVP
British Columbia (BC)	BCHA
Eastern Colorado (ECO)	PSCO
Mountain West (MTWEST)	IPCO & PACE
Northern California (NCAL)	BANC & TID
Pacific Northwest – Montana (PNWMT)	AVA, AVRN, BPA, CHPD, DOPD, GCPD, GRID, GWA, NWMT, PACW, PGE, PSEI, SCL, TPWR, & WAUW
Southern California (SCAL)	IID
Texas – New Mexico (TXNM)	EPE & PNM
Western Colorado (WCO)	WACM

Assistance Reserve Responder Levels

Each Reserve Sharing Zone has multiple levels for providing Assistance Reserve. Level 1 is the list of initial providers. If there is insufficient Assistance Reserve at Level 1 or there are transmission constraints between Reserve Sharing Zones, additional zones will be included by moving out one level at a time until there is sufficient Assistance Reserve or all Participating Balancing Authorities are included.

		Responding Zone									
		AB	AZNV	BC	ECO	MTWEST	NCAL	PNWMT	SCAL	TXNM	WCO
Requesting Zone	AB	-	4	1	6	3	3	2	5	5	5
	AZNV	5	1	4	3	2	4	3	1	1	2
	BC	1	3	-	5	2	2	1	4	4	4
	ECO	6	2	5	-	3	5	4	3	3	1
	MTWEST	3	2	2	4	1	2	1	3	3	3
	NCAL	4	4	3	6	2	1	2	5	5	5
	PNWMT	3	3	2	5	2	2	1	4	4	4
	SCAL	5	1	4	3	2	4	3	-	1	2
	TXNM	5	1	4	3	2	4	3	1	1	2
	WCO	6	2	5	1	3	5	4	3	3	-

Alberta Zone (AB)

Level 1: BC
Level 2: BC + PNWMT
Level 3: BC + PNWMT + MTWEST + NCAL
Level 4: BC + PNWMT + MTWEST + NCAL + AZNV
Level 5: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO
Level 6: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO + ECO

Arizona Nevada Zone (AZNV)

Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

British Columbia Zone (BC)

Level 1: AB + PNWMT
Level 2: AB + PNWMT + MTWEST + NCAL
Level 3: AB + PNWMT + MTWEST + NCAL + AZNV

Level 4: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO
Level 5: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO + ECO

Eastern Colorado Zone (ECO)
Level 1: WCO
Level 2: WCO + AZNV
Level 3: WCO + AZNV + MTWEST + SCAL + TXNM
Level 4: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC
Level 6: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + AB

Mountain West Zone (MTWEST)
Level 1: MTWEST + PNWMT
Level 2: MTWEST + PNWMT + AZNV + BC + NCAL
Level 3: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO
Level 4: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO + ECO

Northern California Zone (NCAL)

Level 1: NCAL
Level 2: NCAL + MTWEST + PNWMT
Level 3: NCAL + MTWEST + PNWMT + BC
Level 4: NCAL + MTWEST + PNWMT + BC + AB + AZNV
Level 5: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO
Level 6: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO + ECO

Pacific Northwest-Montana Zone (PNWMT)

Level 1: PNWMT
Level 2: PNWMT + BC + MTWEST+ NCAL
Level 3: PNWMT + BC + MTWEST+ NCAL + AB + AZNV
Level 4: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO
Level 5: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO + ECO

Southern California Zone (SAL)

Level 1: AZNV + TXNM
Level 2: AZNV + TXNM+ MTWEST + WCO
Level 3: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Texas New Mexico Zone (TXNM)

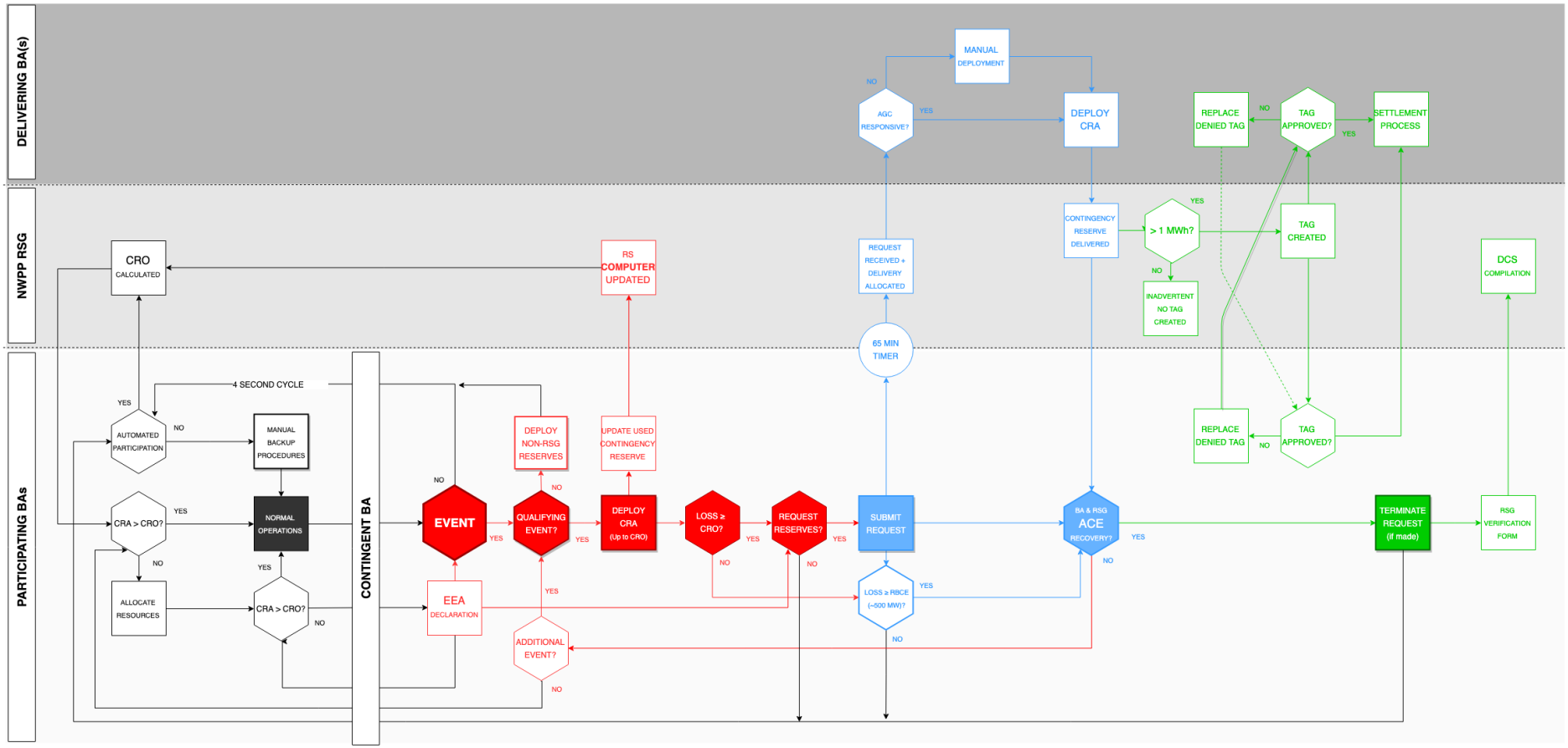
Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Western Colorado Zone (WCO)

Level 1: ECO
Level 2: ECO + AZNV
Level 3: ECO + AZNV + MTWEST + SCAL + TXNM
Level 4: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL
Level 6: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL + AB

Attachment D

NWPP Process Charts



NORMAL OPERATIONS → DISTURBANCE → REQUEST → RESOLUTION

CONTINGENCY RESERVE OBLIGATION (CRO)

- Zonal MSSC
- 3% GENERATION + 3% LOAD

QUALIFYING EVENTS

- Sudden Loss of Generation
- Sudden Loss of an Import
- Sudden Restoration of a Demand
- Energy Emergency Alert

Four Minute Requirement

- 4 min allows adequate response time for ACE
- < 4 mins - RSG responsible
- > 4 mins - BA responsible if compliance failure occurs

RESERVE REQUESTS

- Request is optional
- **RBCE = Reportable Balancing Contingency Event**

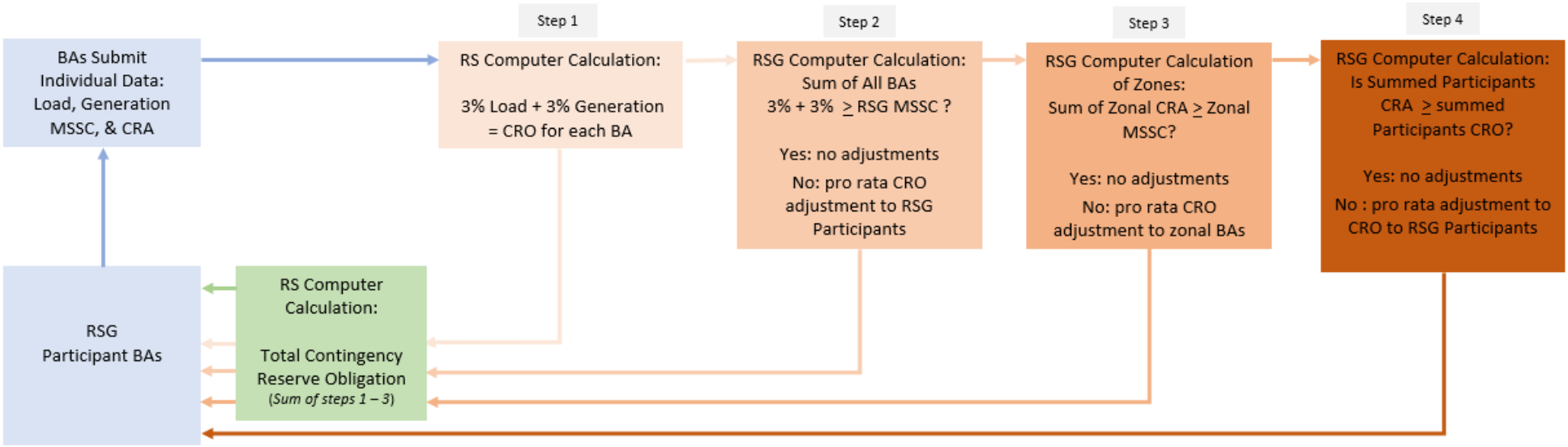
SETTLEMENT

- Powerdex Mid-Columbia Hourly Index

Northwest Power Pool
RESERVE SHARING PROGRAM
PROCESS CHART v19

NORTHWEST PowerPool

Attachment A – Calculation of CRO

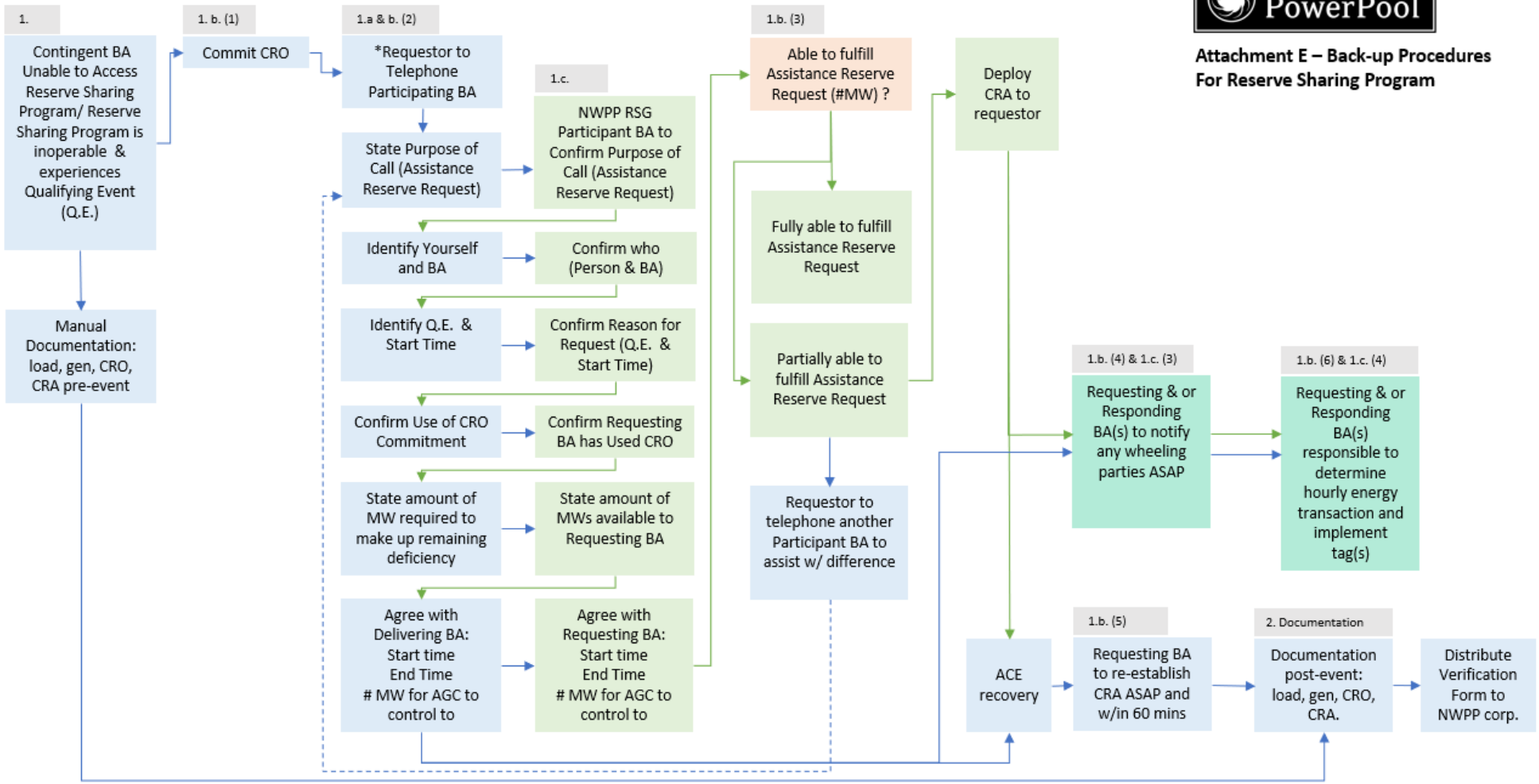


ICCP outputs for each step:
Step 1: BA-CRO
Step 2: BA-ADJ_MSSC_POOL
Step 3: BA-ADJ_MSSC_ZONE
Step 4: BA-ADJCRO_POOL

Total Contingency Reserve Obligation ICCP output: BA-TOTCRO

NORTHWEST PowerPool

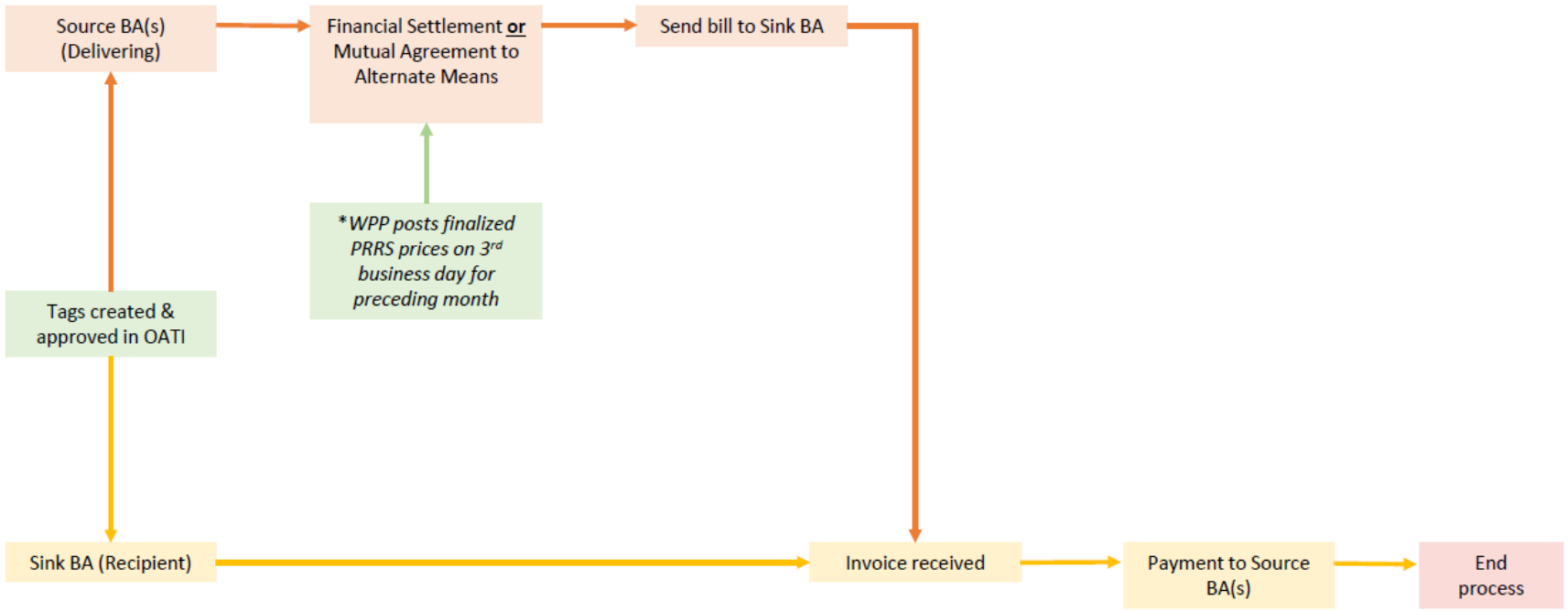
Attachment E – Back-up Procedures For Reserve Sharing Program



* To minimize potential transmission problems call adjacent BA first. If adjacent BA is unable to fulfill Assistance Reserve Request, contingent BA should move and call next adjacent BA. The process would be the same if the adjacent BA is able to partially fill request or unable to fill request.

NORTHWEST PowerPool

Section K – Settlement Process



Attachment E

BACKUP PROCEDURES FOR RESERVE SHARING PROGRAM

1. Participant Cannot Access Reserve Sharing Computer System or Reserve Sharing Computer System Is Inoperable

Reserve Sharing Requests and delivery of Assistance Reserve are normally implemented through the Reserve Sharing Computer System. When the Reserve Sharing Computer System is inoperable or inaccessible, a Participant that needs to make a Reserve Sharing Request should contact other Participants by telephone to request Assistance Reserve. Attachment D reflects the respective process described in this attachment. The provisions below (Sections 1.a, 1.b, and 1.c) will apply for the manual backup procedure. The settlement process for delivery of Assistance Reserve using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

a. Transmission Limitations; Adjacent Utilities

To minimize potential transmission problems, whenever possible a Participant that needs to request Assistance Reserve by telephone should contact an adjacent Participant first.

b. Backup Reserve Sharing Procedure – Telephone Requests

Because NERC BAL-002-3 requires recovery of Reporting ACE within 15 minutes, the number of telephoned assistance requests that a Participant's dispatcher can make is limited. To enhance Participants' ability to meet this standard, Participants may use the following procedure (and Participants may use any economic arrangements under existing contracts by mutual agreement at any point in the following sequence):

(1) As provided in Section E.2, a Participant must commit its Internal Reserve up to the full amount of its Contingency Reserve Obligation before requesting Assistance Reserve.

(2) If a Participant that has deployed its Contingency Reserve Obligation and needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance. The responding Participant will make available its unused Contingency Reserve Available up to its Contingency Reserve Obligation.

The caller must:

(a) state that the purpose of the call is to make a Reserve Sharing Request,

(b) identify who is making the request,

(c) identify the Qualifying Event it has experienced and the start time of the event,

(d) confirm that it committed to use Contingency Reserve up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve that is required to make up the remaining deficiency, and

(f) agree with the responding Participant on the amount, start-time, and end-time of the Contingency Reserve delivery to be entered into the AGC controller total. The end-time may be shortened thereafter, if the requesting Participant determines that it does not need Assistance Reserve through the original end-time.

(3) If the Assistance Reserve made available and delivered from the responding Participant is insufficient to cover the Qualifying Event, the requesting Participant will cover the remaining deficit by requesting Assistance Reserve from another Participant.

(4) As soon as possible, the requesting Participant must notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(5) The Participant requesting assistance must re-establish its Contingency Reserve Available that is ready for deployment (to at least the level of its Contingency Reserve Obligation) as soon as possible by adding generation, adjusting interchange schedules, or dropping load. As provided in Section F.3, a Participant that requests Assistance Reserve must relinquish the Assistance Reserve within 60 minutes following the start of the Qualifying Event.

(6) Any Participant that requests Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to request Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the responding Participant to determine an agreed-upon hourly energy transaction and to agree on transaction wheeling amounts in accordance with the paths identified in the Participants pre-defined tag templates.

c. Backup Reserve Sharing Procedure – Telephone Responses

The following responses may be appropriate for a Participant that receives a Reserve Sharing Request by telephone:

(1) If a Participant that has deployed its Contingency Reserve needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance.

The responding Participant will make available its unused Contingency Reserve up to its Contingency Reserve Obligation.

(2) The Participant that is being asked to provide Assistance Reserve may make the following responses:

(a) confirm that the purpose of the call is to make a Reserve Sharing Request,

(b) confirm who is making the request,

(c) confirm the reason for the request (*e.g.*, identify the Qualifying Event and the start time of the event),

(d) confirm that the requesting Participant has committed to use Contingency Reserve Available up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve available to the requesting Participant,

(f) agree with the requesting Participant on the amount, start-time, and end-time of the Assistance Reserve to be entered into the AGC controller total.

(3) As soon as possible, the responding Participant should notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve energy and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(4) Any Participant that provides Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to provide Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the requesting Participant to determine an agreed-upon hourly energy transaction.

2. Documentation

Any Participant that requests Assistance Reserve using the backup procedures in this Attachment E must document its load, generation, Contingency Reserve Obligation, and Contingency Reserve Available immediately before the Qualifying Event. It must document the amount of its capacity lost or other characteristics of the Qualifying Event, the amount and components of Contingency Reserve deployed, and the amount of Assistance Reserve requested and received. The requesting Participant must also comply with Attachment G, Backup Process for After-the Fact Reserve Sharing Tags.

NWPP RSG Verification Forms are available on the WPP Website. The requesting Participant must send this documentation to all responding Participants, and to the WPP Staff, on the next working day.

Attachment F

TRANSMISSION MAPPING AND TAG TEMPLATE CHANGE PROCESS

A. Process for Changing Tagging Templates Delivery Paths Between NWPP Reserve Sharing Participants

1. Any Participant that wishes to request a change to the transmission mapping set forth in Participants' pre-defined tag templates must first obtain the agreement of all other Participants that would be affected by the requested change.
2. All affected Participants must be given adequate time to make any software changes to downstream or legacy scheduling systems.
3. Participant(s) requesting the change must complete any necessary registrations (or updates to registrations) related to the NAESB Electric Industry Registry (EIR) and Western Interchange Tool (WIT) Registry, or any successor industry registration systems.
4. Participants must submit requests for changes to the tag templates to the WPP Staff.
5. OATI will coordinate testing of the new or revised tag templates and confirm that the templates will pass WIT Registry validations.
6. WPP Staff and the affected Participants will coordinate with OATI to determine an implementation date and time for the new templates.
7. WPP Staff will advise all Participants of the implementation date for the revised templates.
8. OATI will make appropriate tag template changes effective as of the implementation date and time.

B. Process for Changing Tag Templates with No Change to Delivery Paths

(No Impact to Other Balancing Authorities)

1. The Participant with changes will notify the WPP Staff and provide WPP Staff with required changes to its tag templates.
2. The Participant with changes will complete any necessary EIR and WIT registrations or updates.
3. WPP Staff will communicate the requested changes to OATI.
4. OATI will coordinate testing of new or revised tag templates and confirm that the templates will pass WIT validations.

5. WPP Staff and the requesting Participant will determine an implementation date and time for the new tag templates.
6. OATI will make appropriate tag template changes effective as of the implementation date and time.
7. OATI will provide the WPP with the most current workbook of NWPP tag templates.

C. Process for Adding a New Participant to NWPP Reserve Sharing Program

1. WPP Staff will provide a newly admitted Participant(s) with the tag templates for further development to reflect the inclusion of the new Participant(s). If a new Reserve Sharing Zone is required, Attachment C will be revised to reflect the addition of a new Reserve Sharing Zone.
2. The New Participant(s) will provide WPP Staff with a workbook containing only their newly developed tag matrix (to and from each Participant BA) of completed tag templates.
3. WPP Staff will assist with distribution of these new tag templates to all Participants for review as required.
4. Participant(s) must review the new templates and implement any necessary changes to their own accounting and billing systems.
5. WPP Staff will communicate approved new tag templates to OATI.
6. OATI will coordinate testing of the new tag templates and confirm that the templates will pass WIT validations.
7. WPP Staff and all Participants will determine an implementation date and time for the new templates.
8. WPP Staff will advise all Participants of the implementation date and time for the new templates.
9. OATI will make the new tag templates effective as of the implementation date and time.

Attachment G

Backup Process for After-The-Fact Reserve Sharing Tags

A. Failure of Participant Internal Program or Reserve Sharing Computer System

If a Participant that has requested Assistance Reserve (or is providing Assistance Reserve) experiences a failure of any internal program related to reserve sharing, or if a Reserve Sharing Request is made or in effect during a time when the Reserve Sharing Computer System is not functioning, then the Participants receiving and providing Assistance Reserve energy will be responsible for all necessary after-the-fact tagging.

B. Failure of Automated After-the-Fact Tagging Process

If the automated tag creation process fails,

1. WPP Staff will
    a. contact OATI and coordinate the next possible time OATI can rerun automated tag creation for the event;
    b. make reasonable efforts (and request that OATI make reasonable efforts) to give Participants at least 24 hours' advance notice before the reissuing of the tags, and if this is not possible, attempt to give notice as far in advance as feasible; and
    c. notify Participants by e-mail distribution of the re-issuance of the tags.
2. If the affected Participants anticipate that the automated tag creation process will not be able to reissue the tags before the after-the-fact tagging deadline, the sink Participant will coordinate with the source Participants to facilitate the sink Participant's efforts to manually issue after-the-fact tags according to the most recent reserve sharing tag templates.
3. Participants shall contact WPP Staff to resolve failure of the automated tag creation process during normal business hours.

C. Replacing Denied Reserve Sharing Tags

1. If one Participant denies an after-the-fact the tag (properly or not), the denying Participant will coordinate with all other Participants to facilitate the denying Participant's efforts to manually reissue the after-the-fact tag(s).

a. If the problem with the original tag was due to an error in the tag template, the denying Participant will immediately notify all other Participants listed in the template of the necessary correction.

b. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

2. If more than one Participant denies a tag, the sink Participant will coordinate with all other affected Participants to facilitate the sink Participant's efforts to manually reissue the after-the-fact tag.

c. If the problem with the original tag was due to an error in the tag template, the denying Participants will immediately notify all other Participants listed in the template of the necessary correction.

d. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

Attachment H

Balancing Authority Areas of the
Participating Balancing Authorities

Alberta Electric System Operator (AESO)

Arizona Public Service Company (AZPS)

Arlington Valley, LLC (DEAA)

Avangrid Renewables, LLC (AVRN)

Avista Corporation (AVA)

Balancing Authority of Northern California (BANC)

British Columbia Hydro and Power Authority (BCHA)

Bonneville Power Administration (BPAT)

Chelan County Public Utility District (CHPD)

Douglas County Public Utility District (DOPD)

El Paso Electric Company (EPE)

First LightEnergy, LLC (BNBA)

Grant County Public Utility District (GCPD)

Gridforce Energy Management, LLC (GRID)

Idaho Power Company (IPCO)

Imperial Irrigation District (IID)

BHEM Power Watch, LLC (GWA)

Nevada Power (NEVP)

NorthWestern (NWMT)

PacifiCorp East (PACE)

PacifiCorp West (PACW)

Portland General Electric (PGE)

Public Service Company of Colorado (PSCo)

Public Service Company of New Mexico (PNM)

Puget Sound Energy (PSE)

Salt River Project Agriculture Improvement and Power District (SRP)

Seattle City Light (SCL)

Tacoma Power (TPWR)

Tucson Electric Power Company (TEPC)

Turlock Irrigation District (TID)

Western Area Power Administration – Desert Southwest Region (WALC)

Western Area Power Administration – Rocky Mountain Region (WACM)

Western Area Power Administration Upper Great Plains West (WAUW)

Attachment I

Reserved for Future Use

Attachment J

Reserved for Future Use

Attachment K

NWPP Reserve Sharing Group
MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

1. Balancing Authority Area MSSC, NWPP Reserve Sharing Group Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit.

The Participant Balancing Authorities have documented their BAA MSSCs in the table below which are used to derive the Long-Term Zonal MSSC Limit and the NWPP Reserve Sharing Group Long Term MSSC limit under normal system conditions.

Zone	Resource(s)	Reporting/ Operating BAA	Maximum Allowable Zonal MSSC MW	BAA System Normal MSSC MW	Plant Capability	Modeled Outage
Alberta	Genesse #3	AESO	466	466	1286	Loss of generation
Arizona - Nevada	Arlington Generation	AZPS	1122	565	600	Loss of transmission Line
	Arlington Valley	DEAA		580	600	Loss of transmission Line
	BrightNight PV Solar Project	BNBA		300	300	Loss of tie line
	Harquahala – Hassayampa Tie Line	SRP		975	1068	Loss of Transmission Line
	Gila River Blocks 2 &/ 3	TEPC		605	1100	Loss of generation
	Southpoint Energy Center	WALC		250	520	Loss of generation
	Silverhawk	NEVP		620	1055	Loss of transmission Line
British Columbia	Revelstoke – 3 Units	BCHA	1505	1505	2505	Revelstoke 500 kV main bus, three units (5MB2)
Eastern Colorado	Rush Creek Gen Tie	PSCO	1600	1600	1600	RAS Action
Southern California	El Centro Unit 3 / 230kV S-Line	IID	270	117/270	134	Loss of generation or line if scheduled greater than unit
Mountain West	Langley Gulch	IPC	1500	329	329	Unit trip of Langley Gulch – various issues
	Jim Bridger – 2 Units on RAS	PACE		1212	2120	RAS Action
Northern California	Consumnes	BANC	306	306	612	1X1 Generator outage, Gen Tie to plant
	Walnut Energy Center	TID		129	258	Loss of generation
Pacific Northwest - Montana	Noxon Plant RAS Trip	AVA	1500	540	550	Nox 239 East bus with RAS armed

	Schoolhouse	AVRN		598	598	Loss of John Day 239/500 kV transformer
	Columbia Generation Stn	BPAT		1180	1180	Loss of generation
	Rocky Reach – River Crossing 7-8-9	CHPD		410	1272	River crossing 7-8-9
	Wells	DOPD		168	840	Loss of generator step-up transformer (T1-T5) at Wells
	Wanapum – 4 Units	GCPD		440	1000	Trip of Wanapum Powerhouse #1 line or #2 line
	Centralia #2	GRID		710	710	Loss of generation
	BHE Power Watch	GWA		189	189	Loss of Hay Lakke-Rim Rock East & West 230 kV Generation Tie Line
	Clearwater	NWMT		750	1490	Loss of generation or generator lead line
	Chehalis	PACW		540	540	Loss of Napavine-Chehalis 500 kV line
	Carty	PGE		490	490	Loss of generation or generator lead line
	Penstemon Solar, Wild Horse Wind, Vantage Wind	PSE		382	382	230 kV Wind Ridge – Wanapum line
	Boundary Unit #55 or #56	SCL		234	1106	Loss of generation
	Mossyrock	TPWR		203	378	Generator – Transmission outage
	Fort Peck	WAUW		44	90	Loss of generation
Texas – New Mexico	Newman 5 in 2x1 configuration	EPE	900	228	268	Loss of generation
	Afton	PNM		235	235	Loss of generation
Western Colorado	Laramie River Station #2 or #3	WACM	570	570	570	Loss of generation

NWPP RSG Long-Term MSSC Limit	**Eastern Colorado Zone**		**1600**			

2. Jointly Owned Dynamic Generation Resources

This table below is a listing of jointly owned dynamic generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Four Corners 4	APS	770	1540	AZPS 70%	*
Four Corners 5		770		PNM 13%	*
				SRP 10%	*
				TEPC 7%	*
Pale Verde 1	APS	969	2907	APS	*
Pale Verde 2		969		EPE	*
Pale Verde 3		969		PNM	*
				SRP	*
Rock Island	CHPD	216	606	AVA 10%	*
				CHPD 50%	*
				PSE 40%	*
Rocky Reach – River Crossing 7-8-9	CHPD	410	1272	AVA 10%	*
				CHPD 44.46%	*
				DOPD 5.54%	*
				PSE 40%	*
Wells	DOPD	168	840	AVA	*
				CHPD	*
				DOPD	*
				PSE	`*

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Priest Rapids – 4 Units	GCPD	365	930	AVA	*
				GCPD	*
				PACW	*
				PGE	*
				PSE	*
				SCL	*
				TPWR	*
Wanapum - 4 units	GCPD	440	1000	AVA	*
				NWMT	*
				PACW	*
				PGE	*
				PSE	*
Colstrip 3 & 4	NWMT	740	1480	AVA	222
				NWMT	444
				PACW	148
				PGE	296
				PSE	370
					1480
Luna	PNM	570	570	PNM 66.33%	380
				TEPC 33.33 %	190
					570
Hermiston / Perennial	PACW	474	474	GRID	237
					237
					474

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Jim Bridger – RAS 2 Unit + Remote Wind	PACE	1212	2120	IPC	707
				PACE	1413
					2120
Gila River - *Blocks 1 & 4	SRP	550	2200	SRP 100%	1100
Gila River - *Blocks 2 & 3	TEPC	585		SRP 100%	1100
					2200
TEP and SRP have their own share based on blocks. *Under normal conditions this is not a JOU however SRP may report entire 2200MW based on N-4 conditions.*					
Springerville 1 & 2	**TEPC	450		TEP	*
Springerville 3	*PNM	458		PNM	*
				SRP	*
PNM does not own the generation, but PNM ACE is affected by the loss of generation and must request MW during disturbances to recover. **Under normal conditions this is not a JOU however TEP may report the entire amount based on potential N-4 conditions*					
Springerville 4	SRP	410		SRP	*

3. Jointly Owned Static Generation Resources

This table is a listing of jointly owned static generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Valmy	NEVP	268	395	IPC	134
				NEVP	261
					395

4. Multi Use Transformer(s)

This is a listing of transformers that are jointly utilized that could be a BCE under studied outage configurations.

Transformer(s)	Operating BA	Facility Rating	BA(s) with associated transformers	Generators	Generating Capacity in MW
John Day	BPA	1300 MVA	AVRN	Klondike I, II, III A, III GE, III Siemens, Starpoint, Hay Canyon, Golden Hills	809
			PGE	Biglow 1, Biglow 2, Biglow 3	450
					1259
Slatt	BPA	1300 MVA	AVRN	Montague Wind, Montague Solar	363
			BPA	Shepherds North (North Hurlburt)	265
			BPA	Shepherds South (South Hurlburt)	290
			BPA	Horseshoe Bend (Shepherds Central)	290
					1208
Rock Creek	BPA	1300 MVA	AVRN	Juniper Canyon, Lund Hil	299
			BPA	Windy Flats/Dooley	262
			BPA	White Creek Wind	205
			BPA	Harvest Wind	99
			PAC	Goodnoe Hills	150
					1015

Attachment L

Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

The following is a listing of the NWPP Reserve Sharing Group Participants that are monitors of the major transfer facilities and cut planes between Reserve Sharing Zones:

1) The Alberta Electric System Operator Balancing Authority (AESO) monitors the cut plane connecting the Alberta Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

2) The Bonneville Power Administration (BPA) Balancing Authority monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

3) The Idaho Power (IPC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Pacific Northwest-Montana Reserve Sharing Zone,

4) The Balancing Authority of Northern California Balancing Authority (BANC) monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone,

5) The PacifiCorp (PAC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Arizona Nevada Reserve Sharing Zone,

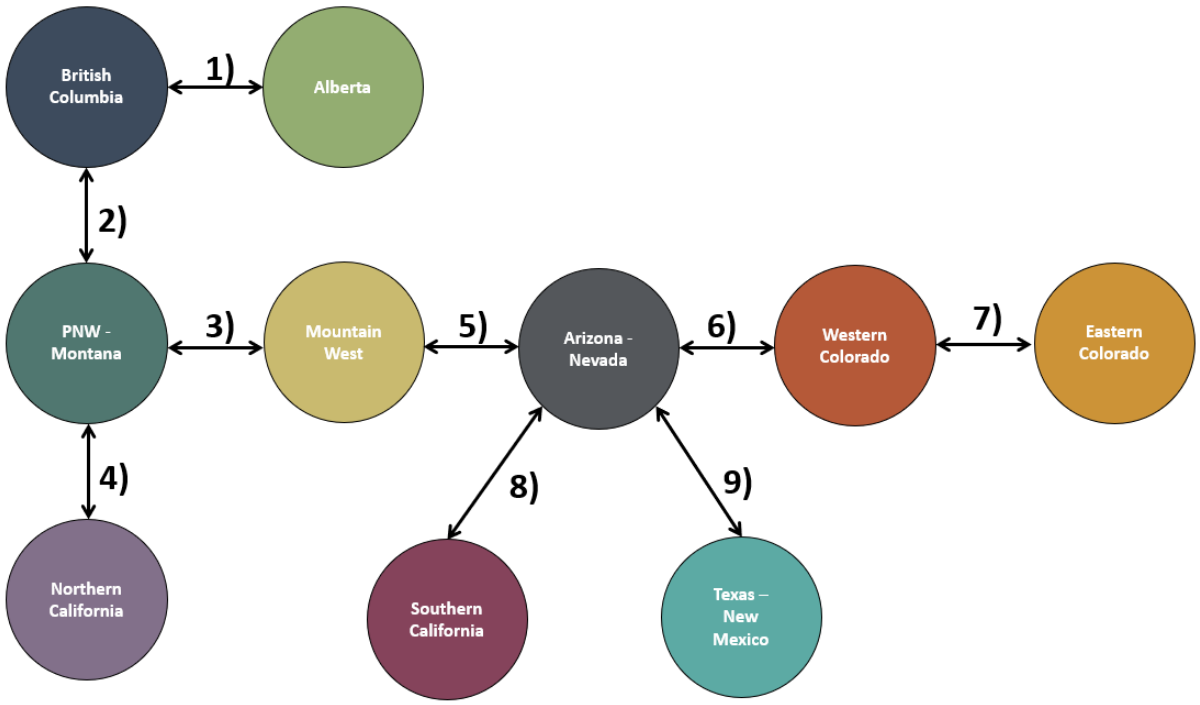
6) The Western Area Power Administration's Rocky Mountain Region (WACM) and Lower Colorado (WALC) Balancing Authorities monitor the cut plane connecting the Arizona Nevada Reserve Sharing Zone with the Western Colorado Reserve Sharing Zone,

7) The Western Area Power Administration's Rocky Mountain Region (WACM) Balancing Authority monitors the cut plane connecting the Western Colorado Reserve Sharing zone with the Eastern Colorado Reserve Sharing Zone,

8) The Imperial Irrigation District (IID) Balancing Authority monitors the cut plane connecting the Southern California Reserve Sharing zone with the Arizona Nevada Reserve Sharing Zone, and

9) The El Paso Electric Company (EPE) Balancing Authority monitors cut plane connecting the Arizona Nevada Reserve Sharing zone with the Texas New Mexico Reserve Sharing Zone.

See supporting picture of cut planes as identified above and represented between each of the zones:



Attachment M

Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Background:

This attachment (1) describes the operation and purposes of BPA Remedial Action Schemes (as defined in the NERC Glossary; also known as RAS) that are designed to drop generation and intentionally suspend Automatic Generation Control (AGC) actions to achieve the required flow mitigation effects of the RAS for transmission line outages that have large impacts to the integrity of the Western Interconnection, (2) explains why efforts by a Participating Balancing Authority or by the NWPP Reserve Sharing Group to immediately recover NWPP Reserve Sharing Group Reporting ACE following operation of this category of RAS would undermine the designed reliability benefits of the RAS, and (3) explains that the change in NWPP Reserve Sharing Group Reporting ACE that results from the planned, intentional generation dropping of these RAS is not unexpected and therefore does not meet the definition of a Balancing Contingency Event.

RAS Description:

For certain types of potential exceedances of System Operating Limits and Interconnection Reliability Operating Limits (SOL/IROL), BPA has designed RAS to intentionally drop generation and suspend related AGC actions. This category of RAS is intended to mitigate flow and stability impacts associated with various contingency events on transmission facilities. These transmission facilities are designed to operate at maximum transfer levels that rely on protection provided by the associated RAS. For example, RAS for the California-Oregon Intertie system (COI) and Pacific Direct Current Intertie system (PDCI) are in this category. There are other transmission facilities in the Northwest that also rely on this category of RAS to maximize transfer capability. Additional remedial actions for this category of RAS may include other actions such as fast switching of reactive devices and insertion of dynamic braking resistors.

This category of RAS intentionally suspends AGC within the BPA Balancing Authority and any other host Balancing Authorities of the associated generating units to avoid counteracting the intended flow mitigation benefit of the RAS. Even with AGC suspended, active governors of synchronized generators are expected to respond to the changed load-resource balance and resulting frequency drop. The Bulk Electric System within the Western Interconnection, including the affected areas, are expected to perform according to the BAL-003 requirements and immediately provide primary frequency control through governor action to arrest the frequency decline and stabilize the system.

Overall system recovery continues as the affected systems adjust transfers and generation or deploy contingency reserves, and the affected systems rebalance for the new level of transfers associated with the SOL/IROL. Each affected Balancing Authority restores its AGC once

transfers are adjusted. Generation then ramps up (receiving areas with imports curtailed) or down (sending areas with exports curtailed) to the new required levels, which enables each affected Balancing Authority to recover its Reporting ACE.

The Significance of BPA RAS in Relation to Reporting ACE:

Because certain planned generation dropping through RAS action is intended to protect affected transmission facilities within the NWPP from overloads, instability, or cascading outages, any action by Participants in the NWPP Reserve Sharing Group to immediately recover Reporting ACE following these specific RAS events may adversely affect reliability of the Bulk Electric System. Changes to the NWPP Reserve Sharing Group's Reporting ACE due to RAS actions are expected and, as such, are not Balancing Contingency Events. Generation is dispatched appropriately to accommodate the post-RAS system configuration, which may take more than 15 minutes.

BPA is responsible for notifying the WPP Staff whenever an event involving operation of this category of RAS has occurred, and therefore 15-minute recovery of NWPP Reserve Sharing Group Reporting ACE is not expected for that event.

Attachment N

Correlation Table of Participants, Reliability Coordinators, and Reserve Sharing Zones

Participant	Reliability Coordinator	Zone	Transfer Date
AESO	AESO	AB	N/A
AZPS	RC West	AZNV	11/1/2019
DEAA	SPP	AZNV	12/1/2019
AVA	RC West	PNWMT	11/1/2019
AVRN	RC West	PNWMT	11/1/2019
BANC	RC West	NCAL	7/1/2019
BCHA	BCHydro RC	BC	9/2/2019
BNBA	SPP	AZNV	7/1/2025
BPAT	RC West	PNWMT	11/1/2019
CHPD	RC West	PNWMT	11/1/2019
DOPD	RC West	PNWMT	11/1/2019
EPE	SPP	TXNM	12/13/2019
GCPD	RC West	PNWMT	11/1/2019
GRID (North)	SPP	PNWMT	12/3/2019
GRID (South)	SPP	AZNV	12/1/2019
GWA	RC West	PNWMT	11/1/20219
IID	RC West	SCAL	7/1/2019
IPC	RC West	ID	11/1/2019
NVE	RC West	HD	11/1/2019
NWMT	RC West	PNWMT	11/1/2019
PACE	RC West	PNWMT	11/1/2019

PACW	RC West	PNWMT	11/1/2019
PGE	RC West	PNWMT	11/1/2019
PSCO	SPP	ECO	12/3/2019
PNM	RC West	TXNM	11/1/2019
PSEI	RC West	PNWMT	11/1/2019
SRP	RC West	AZNV	11/1/2019
SCL	RC West	PNWMT	11/1/2019
TEP	SPP	AZNV	12/1/2019
TID	RC West	NCAL	7/1/2019
TPWR	RC West	PNWMT	11/1/2019
WACM	SPP	WCO	12/3/2019
WALC	SPP	AZNV	12/1/2019
WAUW	SPP	PNWMT	12/3/2019

DOCUMENTATION HISTORY

Updates:	Date:
NWPP Reserve Sharing Program	1-18-2006
Accommodation for new Balancing Authorities: SMUD & TID	6-07-2007
Combining of SPP and PACE zones into SPP-PACE zone	3-31-2008
Update of section D.3 for jointly owned generation	5-18-2008
Accommodation for new Balancing Authorities: GWA	10-13-2008
Updated terminology and addition of Attachments F, G, and H.	1-30-2009
Update of Attachment D to reflect tag template updates	3-31-2009
Update for requirement omission from 10-13-2008 version to 01-30-2009 version	3-31-2009
Clarity to sections I.5.l and H.2	4-8-2009
Update for computer failure, continuance to deliver reserve for full 60 minutes	4-8-2009
Clarification to Attachment B – Covered contingencies	5-12-2009
Update to Attachment B – Loss of wind generation due to temperature	7-1-2009
Grammar revision to definition of "Reportable Disturbance"	7-30-2009
Accommodation of information for the ACE Diversity Interchange (ADI) program	10-15-2009
Update of Attachment D – transmission mapping between NWMT and PGE	11-1-2009
Clarifying revisions and reorganization throughout; addition of language to Attachment B specifying Operating Committee authority to designate additional "Qualifying Events"; addition of Attachment K	10-18-2010
British Columbia Hydro and Power Authority NERC Registry acronym change from BCTC to BCHA	12-1-2010
Addition of definition of "RSG Committee"; replacement of most references to Operating Committee and all references to NWPP Reserve Sharing Subcommittee with references to RSG Committee; Updates of Attachment K	4-6-2011
Revision to Attachment B – addition of energy emergency as a Qualifying Event	10-5-2011
Update to section K.3. Financial Settlement with Powerdex Mid-Columbia Hourly	1-1-2012
Update to definition of Single Contingency, Section J.1.f with additional request language, and Section K.3. Financial Settlement clarification	6-7-2012
Revisions to Section 1.a of Attachment A to incorporate new requirements for photovoltaic and other types of generation; threshold in second bullet of	

definition of "Reportable Disturbance" lowered from 190 MW to 170 MW and updates to Attachment K Tables 1 and 3 1-10-2013

Clarifying updates throughout document including the addition of Section D.3.f, revisions to Sections E.2, E.4, F and updates to Attachments B, C, F and K 4-4-2013

Update to Attachment B and removal of (e) Unexpected loss of Contingency Reserve with new language to section (c) 6-6-2013

Updates to Attachments D, H, and K for incorporation of the NaturEner Wind Watch BA, WWA into program documentation 10-30-2013

Updates to Attachments D, H, and K for incorporation of the Constellation Energy Control and Dispatch BA, WWA into program documentation along with other clarifying updates throughout the document 11-25-2013

Updates to Attachments C, D, H, and K to reflect Nevada Power Company (NEVP), as operator of the consolidated Balancing Authority Area encompassing the Balancing Authority Areas previously operated separately by Sierra Pacific Power Company (SPPC) and Nevada Power Company (NEVP) 1-9-2014

Revisions throughout document to reflect implementation of WECC Standard BAL-002-WECC-2, to incorporate terms governing Loss of a Unit-Contingent Purchase, and to reflect the name change of the organization formerly known as Constellation Energy Control and Dispatch (CSTO) to Gridforce Energy Management, LLC (GRID) 8-15-2014 – Effective 10-1-2014

Revisions to incorporate language concerning RSG compliance with R3 and R4 of WECC BAL-002-WECC-2 8-22-2014 – Effective 10-1-2014

Clarifying revisions to the description of Contingency Reserve Obligation calculation in Attachment A, with conforming changes in body of document and other minor clean-up items 1-8-2015

Clarifying revisions to timing of requests for assistance reserve in section E.3; changes to section I.2, Major Transmission Facility Information; Attachment A, revisions regarding Balancing Authority Calculation of Contingency Reserve Obligation When Communications with Reserve Sharing Computer System Are Disrupted; and a new Attachment L, Transmission Facilities Making up Cut Planes Between Reserve Sharing Zones 4-2-2015

Clarifying revisions to section K.3.e to address how and when the NWPP Staff will complete and post calculations of applicable settlement prices 4-17-2015 – Effective 5-1-2015

Revisions to "Introduction and Overview" section to clarify that NWPP Staff are responsible for compliance reporting, not individual Participants; revisions to Section D.4.b to require at least quarterly reporting of data for R.3. and R.4 of WECC Standard BAL-002-WECC-2	10-8-2015
Addition and incorporation of the defined term "Contingency Reserve Available" and editorial cleanup revisions	4-1-2016
Clarifications related to NWPP Reserve Sharing Program participation status, determining real-time Most Severe Single Contingency, and reflection of NWPP Reserve Sharing Program requirements in Participant operating procedures	10-13-2016
Removal of language in Attachment B Qualifying Events, (d) Declaration of Energy Emergency Alert 2 or 3	05-12-2017
Effective May 12, 2017 - Participation in WECC Field Test Waiving Enforcement of BAL-002-WECC-2a, Requirement R2	05-12-2017
Revisions to harmonize definitions and other relevant provisions to NERC Standard BAL-002-2(i) and the NERC Glossary; miscellaneous cleanup and clarifying revisions	10-25-2017
Newly added definition for Operating Plan, clarifying changes to MSSC definition, and conforming changes sections D. 3., E.4. and L.	11-30-2017
Clarifying changes to term Reserve Sharing Zone, addition of terms: System Operator, BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; clarifying changes to Sections D.3.j, revisions to Section I.1,, addition of Section I.5.d., clarifying changes to Attachment A of BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; revisions to Attachments D, H, and K to reflect addition of Avangrid Renewables as a new Participant. Changes to update the WECC and NERC BAL-002 standards to conform through the entire document.	5-10-2018
Clarifying changes to section D.3.k. to clarify NWPP RSG procedures related to Energy Emergency Alerts. In addition, clarifying language was added to Section L. regarding Obligation to submit a NWPP RSG Verification Form and new Section L.2. added regarding Reporting Balancing Obligation to Notify NWPP Staff.	11-8-2018

New term added for NWPP Reserve Sharing Group Reporting ACE. In addition, new Attachment M – *Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE* and Attachment N -

Correlation Table of Participants, Reliability Coordinators and Zones. Clarifying changes to section I.5. regarding data telemetered from Reserve Sharing Program to the Reliability Coordinator with the addition of the NWPP RSG Reporting ACE and new Section I.6. – Management of Data Related to Reserve Sharing Zones. 2-14-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-14-2019

Clarifying notes to Attachment B - Qualifying Events with new *note 2* and formatting (similar to NERC Definition for Balancing Contingency Event). Additional housekeeping items to clarify front page with BAL-002-WECC-2a, Section H.3. with updated contact information, corrected bulleting in Attachment A, and updated Attachment L with appropriate AESO Cut Plane facilities. 5-16-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-16-2019

Clarification to WECC Waiver regarding BAL-002-WECC-2a R2. Balancing Contingent Event term added and conforming changes throughout document for a Reportable Balancing Contingent Event. Reporting ACE clarification to Section I.1.f. and J.2.a. Language added to section L.1 to address RSG reporting of EEAs. Clarification of zones to response levels to Attachment C, including new tables for zones and associated BAs along with responding levels. In addition, the removal of Attachment D with new reference to NWPP RSG Tag Templates and conforming changes. Housekeeping changes to conform document with Attachment N. 7-1-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 7-1-2019

Updates to address the addition of new BA Participants, WACM and PSCO for live operation 9-3-2019. Conforming changes throughout document (Section I.2., I.4.d., Attachment C, Attachment H, Attachment K, Attachment L, and Attachment N). 7-1-2019 – effective 9-3-2019

Revisions to Attachment M by removing "Reportable" from references to Balancing Contingency Event. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-7-2019

Clarifications made to section E.3. Timing of Requests for Assistance Reserve. Additions to section H.3. with respect providing ICCP failover notifications to NWPP staff. Revisions to section I.5. regarding Data Telemetered to the RCs and elimination of section I.6 as it is all covered in the revised section I.5. Revisions to section K. Settlement with the elimination of Energy In-Kind settlement and conforming changes. 11-7-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-6-2020

Housekeeping update to WECC Waiver extension to BAL-002-WECC-2a R2 on front page. 4-6-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Addition of Process Diagrams as Attachment D (General Process Diagram, Settlement Process, Calculation of CRO, and Back-up Procedures). Consistent naming of generator contingencies in Attachment K. 5-7-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revised Section B. term for *Participating Balancing Authority or Participant*. Revisions to Section C.3. to address Balancing Authority versus Balancing Authority Area and program functionality. Revisions to Section F. to further clarify program functionality for commitment of Contingency Reserve Obligation when requesting Assistance Reserve, including conforming changes to Section I.4.d. and elimination of Section 2. *Discretion of Participating BA to Carry More Contingency Reserve Than Required by Calculation of Minimum Contingency Reserve Obligation; Obligation to Make All Reported Contingency Reserve Available*. Section I.1. revision and addition of new data from Participant BAs to program (BA_FBS, BA_Ime, BA_ATEC, and BA_ADI). Updates to section L. as related to Internal RSG Reporting. Revisions to Attachment A, Section 1. to address program update to MSSC Deadbands. Attachment K MSSC Updates to PGE MSSC. 11-5-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Revisions to Section B. Terminology's *BAL-002* term. Revisions to Sections E.2. regarding actions required to respond to an EEA. Revisions to Section

E.3. regarding length of time for accessing Contingency Reserve to respond to EEAs. Conforming changes to address Section B. *Contingency Reserve Available* term relating to EEA. Last, updates to Section I.1. h. & i. to reflect correct use of NI_A and NI_S. 2-4-2021

Updated language to Section H.2. to for NWPP Staff to perform analysis on each Reportable Balancing Contingency Event that the NWPP RSG experiences. 3-30-2021

Updated cover page to reflect WECC-0115 BAL-002-WECC-2a, Requirement R2, Compliance Waiver Extension 4-6-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revisions to section D.2. to address appropriate reference to Attachment A and its sections. Revisions to Attachment A. 1 to remove the 1.5 shortfall multiplier to address the current functionality of computer program. 5-6-2021

RSGC approved updates (Feb. 4, 2021) to conform documentation with new Standard BAL-002-WECC-3, effective June 28, 2021 6-28-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-5-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Clarifying changes to Contingency Reserve Available (CRA) term, clarifying changes to NWPP Reserve Sharing Group Reporting ACE term, clarifying changes to Section D.3.i - ACE recovery period and size, clarifying changes to Section I.3.j. & k to address calculation of Reporting ACE, addition to Section F. regarding metrics for Deployment of Contingency Reserve, clarifying changes to Section H. regarding Participant responsibilities related BA footprint changes to MSSC (Unit configuration, RAS, etc.), and update to Section K.2.c. regarding annual review period. 11-5-2021

Updates to Section H. to address clarifications to Roles and Responsibilities of the Participant, NWPP Staff with on-call support 24x7, and RSG Committee. 1-12-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Addition of new to Sections I.4. p. and I.4.q. as approved in 2018.11.09. 2-3-2022

Updated Attachment K Tables with new Table 4 to address AVRN's new Gold Hills Wind Project

connected to BPA transformer. 3-11-2022

Housekeeping from NWPP to WPP (*NWPP doing business as WPP*), including associated email addresses. Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-5-2022

Updated Attachment K Tables with PAC transfer of Jim Bridger from PACW to PACE BAA, updating new MSSCs for both, effective July 6, 2022 6-29-2022

More conforming updates to address NWPP to WPP. New Section E.3. and conforming changes to address performance metric for deployment of Contingency Reserve. Updates to Section K.2. Financial Settlement from use of Powerdex to the Intercontinental Exchange (ICE) in October 2022 (Mid-Columbia and Palo Verde). Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-4-2022

Section B. Clarifying updates CRA Definition and conforming updates to Section D.3.b., Section E.2. and Section J.1. Section B. new term: 'Recovery Reporting ACE Target'. Performance Metric updates to Section E.4 and F. Clarifying updates to section K.2.Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-3-2022

Attachment K Tables updated with GCPD MSSC to Tables 1 - Priest Rapids and Table 3 - Wanapum. 12-21-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 with GCPD MSSC and clarifying change to term 'Recovery Reporting ACE Target' 2-2-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Colstrip Capacity Numbers, Table 2 Valmy Shares, and Table 3 AESO Plant Capability, 5-4-2023

Updated NaturEner Attachment H with NaturEner Balancing Authority Name change to BHEM Power Watch, LLC and BHEM Wind Watch, LLC 5-5-2023

Updated Qualifying Events from all EEAs to EEA3 only – Deleted previous section D.3.k (Script for talking to RC to prevent unnecessary EEAs). Clarifications to Sections E.2

., E.3. Attachment B.

6-8-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-3-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for PACE and GCPD along with Table 3 for PACE. 11-2-2023

Updates to conform documentation with zonal transition from Idaho and High Desert Zones to Mountain West and Arizona Nevada Zone to Section I.2., Attachments C, K, L & N. 1-24-2024

Clarifying language added to Section F, newly added Section P – Penalties for Non-Performance (Effective July 1, 2024), and conforming changes to Section I.4.c. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Rocky Reach-River Crossing 7-8-9 Participants. 2-8-2024

Conforming changes with the addition of the new Balancing Authority Participants (AZPS, DEAA, EPE, IID, HGMA, PNM, SRP, TEPC, WALC) effective May 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment L updates and conforming changes to Section I.2., and Attachment N. In addition, consistency with use of term 'RSG Committee', removal of standards documentation to Attachment I NERC BAL-002 and Attachment J BAL-002-WECC. 3-20-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for BANC and TEPC 5-17-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2024

Updates to Section P for a review process to allow for partial credit, to provide clarity that an entity may still receive credit for the "clock-minute averages" independently of meeting the Recovery Reporting ACE Target criteria. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining

system reliability. 11-7-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Program Documentation with new terms: Balancing Authority Area MSSC, Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit. Conforming changes to Section M to address MSSC limits, and conforming changes to Attachment K Table 1 with Maximum Allowable Zonal MSSC and NWPP RSG Long-Term MSSC Limit. 2-6-2025

Review and update to Attachment K, 1. column header from BAA MSSC MW to BAA System Normal MSSD MW. 2-12-2025

Conforming changes with the consolidation of HGMA BA into SRP BA, effective June 1, 2025, the addition of the new First LightEnergy, LLC BA (BNBA), effective July 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment N. 7-1-2025

Updates to Attachment K, 1. BAA MSSC for NEVP and 2., adding back Jim Bridger for PACE and IPC. 9-23-2025

Conforming changes with the consolidation of BHE Montana's WWA BA into the GWA BA, effective October 1, 2025. 10-1-2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-146:
Western Frequency Response Sharing Group

WESTERN FREQUENCY RESPONSE SHARING GROUP

As permitted by the NERC Standard, BAL-003-2, many Balancing Authorities within the Northwest Power Pool Area have instituted the Western Frequency Response Sharing Group (WFRSG). By collectively participating in the WFRSG, participants are entitled to calculate their annual Frequency Response Measure (FRM) in aggregate to achieve an FRM that is equal to or more negative than its' (the WFRSG) FRO to assure sufficient Frequency Response is provided to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

MORE INFO

NOTIFY ME

DOCUMENTS | VIEW ALL

WFRSG - WFRSGC

WFRSG Agenda and Meeting Materials

WFRSG Agenda and Meeting Materials

LOCKED

WFRSG - WFRSGC

2024 Q3 Updates - FRS Form 1 and FRS Form 2

LOCKED

WFRSG - WFRSGC

2024 Q2 Updates - FRS Form 1 and FRS Form 2

LOCKED

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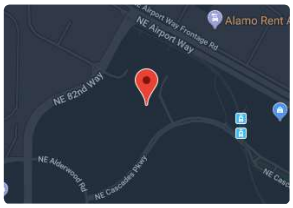

PROGRAMS

NEWS

EVENTS

DOCUMENTS

ABOUT

SIGN IN

WESTERN

CONTACT

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-147:
WRAP Tariff

WESTERN RESOURCE ADEQUACY PROGRAM

TARIFF

OF

NORTHWEST POWER POOL

D/B/A

WESTERN POWER POOL

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SCHEDULE 1
WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

ATTACHMENT A
Western Resource Adequacy Program Agreement

PART I GENERAL PROVISIONS

1. Definitions

Unless the context otherwise specifies or requires, capitalized terms used in this Tariff shall have the respective meanings assigned herein for all purposes of this Tariff (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Parts, Sections, Schedules, or Attachments, are to Parts, Sections, Schedules, or Attachments of this Tariff.

Applicable Price Index: A published index of wholesale electric prices, or Locational Marginal Prices duly calculated and posted by a FERC-regulated market operator, in either case as designated under Part III of this Tariff for use in connection with an identified Subregion.

Administration Charge or WRAP Administration Charge: The charge established under Schedule 1 of this Tariff for recovery of the costs of the WRAP.

Advance Assessment: Analyses and calculations of Participant load, resource, and other information performed in advance of each Binding Season as set forth in Part II of this Tariff.

Aggregate Capacity Deficiency: As to a Binding Season, the sum of the maximum Monthly Deficiencies of all Participants that submitted FS Submittals for such Binding Season, as determined following completion of the Cure Period for such Binding Season.

Available Transfer Capability ("ATC"): Transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Base Costs: Base Costs shall have the meaning provided in Schedule 1 of this Tariff.

Base Services Cost Centers: The cost centers comprising the Base Charge as defined in Schedule 1 of this Tariff.

Base Services Percentage: Base Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Binding Season: The Summer Season or the Winter Season.

Board of Directors or Board: The Board of Directors of the Northwest Power Pool d/b/a Western Power Pool.

Business Day: Any Day that is a Monday through Friday, excluding any holiday established by United States federal authorities.

Business Practice Manuals: The manuals compiling further details, guidance, and information that are appropriate or beneficial to the implementation of the rules, requirements, and procedures established by this Tariff. Business Practice Manuals do not include such internal rules or procedures as the Western Power Pool may adopt for its operation and administration, including but not limited to any corporate by-laws of the Western Power Pool, or for any services or functions provided by the Western Power Pool other than those established by this Tariff.

CAISO: The California Independent System Operator Corporation, a California nonprofit public benefit corporation.

Capacity Benefit Margin: An amount of transmission transfer capability permitted under open access transmission rules to be reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Critical Hours ("CCH"): Those hours during which the net regional capacity need for the WRAP Region is expected to be above the 95th percentile, based on historical and synthesized data for the WRAP Region's gross load, variable energy resource performance, and interchange.

Capacity Deficiency: A shortfall in a Participant's Portfolio QCC relative to that Participant's FS Capacity Requirement, as further defined in Part II of this Tariff.

Cash Working Capital Fund: Cash Working Capital Fund shall have the meaning provided in Schedule 1 of this Tariff.

Cash Working Capital Support Charge: A charge assessed to Participants under Schedule 1 of this Tariff to fund the Cash Working Capital Fund.

Cash Working Capital Support Charge Rate: Cash Working Capital Support Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Central Hub: A designated point or named group of points on the transmission system within a Subregion identified by the Program Administrator that permits energy deliveries from multiple points within such Subregion.

Cost of New Entry ("CONE"): The estimated cost of new entry of a new peaking natural gas-fired generation facility, as determined under, and used in, Part II of this Tariff.

CONE Factor: A factor employed in the calculation of Deficiency Charges under Part II of this Tariff, to reflect whether, and the extent to which, the WRAP Region as a whole is expected to have a capacity deficiency during the period for which the Deficiency Charge is being calculated or a factor employed when a Participant has had repeated deficiencies in sequential years.

Committee of State Representatives ("COSR"): Committee of State Representatives, as established in Part I of this Tariff.

Contingency Reserve: As more fully described in the NERC WECC reliability standards, a quantity of reserves, consisting of generation, load, interchange, or other resources, that are deployable within ten minutes, equal to the greater of (i) the MW quantity of the loss of the most severe contingency and (ii) the megawatt quantity equal to the sum of 3% of hourly integrated load plus 3% of hourly integrated generation.

Critical Mass: *The threshold level of participation in a Subregion, as established in the Business Practice Manuals, below which each Participant of such Subregion may elect to participate as a Non-Binding Participant.*

Cumulative Delivery Failure Period: Any period of five consecutive years, ending with and including the most recent Energy Delivery Failure as of the time of determination of a possible Delivery Failure Charge.

Day: A calendar day.

Day-Ahead Price: A price for wholesale electric transactions designated as a day-ahead price in an Applicable Price Index.

Default Allocation Assessment: A charge assessed on non-defaulting Participants to recover the costs associated with a default by a Participant, as set forth in Part I of this Tariff.

Deficiency Charge: A charge assessed for a Capacity Deficiency or Transmission Deficiency, as set forth in Part II of this Tariff.

Delivery Failure Charge: A charge assessed for a Participant's failure to deliver a required Energy Deployment, as set forth in Part III of this Tariff.

Delivery Failure Charge Rate: A rate employed in the determination of a Delivery Failure Charge as more fully set forth in Part III of this Tariff.

Delivery Failure Factor: A factor used in the determination of a Delivery Failure Charge to recognize the relative severity or impact of an Energy Delivery Failure, as set forth in Part III of this Tariff.

Demand Response: A quantifiable load reduction or otherwise controllable load for which a Participant has two mutually-exclusive options to use to affect its FS Capacity Requirements in a FS for a Binding Season: (1) leave the effects of historically deployed demand response as part of its load provided for the Advance Assessment; or (2) utilize as a Demand Response Capacity Resource.

Demand Response Capacity Resource: A Qualifying Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements established under Part II of this Tariff utilized to meet a Participant's FS Capacity Requirement.

Demonstrated FS Transmission: A Participant's demonstration in its Forward Showing Submittal that it has secured firm transmission service rights of the type and quantity sufficient to provide reasonable assurance, as of the time of the Forward Showing Submittal, of delivery of

capacity from the Qualifying Resources and the resources associated with the power purchase agreements in the Participant's Portfolio QCC.

Discounted Deficiency Change: *A reduced Deficiency Charge during the Transition Period that enables a deficient Participant that demonstrates commercially reasonable efforts but is unable to cure deficiencies to access Operations Program capacity.*

Dual Benefit Cost Centers: Dual Benefit Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Effective Load Carrying Capability ("ELCC"): A methodology employed to determine the Qualified Capacity Contribution of certain types of Qualifying Resources, as more fully set forth in Part II of this Tariff.

Energy Declined Settlement Price: A pricing component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Energy Delivery Failure: A failure by a Participant to provide an Energy Deployment assigned to such Participant under Part III of this Tariff.

Energy Deployment: A delivery of energy that a Participant is required to provide during an Operating Day, as set forth in Part III of this Tariff.

Energy Storage Resource: A resource, not including a Storage Hydro Qualifying Resource, designed to capture energy produced at one time for use at a later time.

Excused Transition Deficit: A Participant's inability during the Transition Period to demonstrate full satisfaction of the Participant's FS Capacity Requirement, which, under certain conditions and limitations prescribed by Part II of this Tariff, permits *the Participant to pay a Discounted* Deficiency Charge.

Federal Power Marketing Administration: A United States federal agency that operates electric systems and sells the output of federally owned and operated hydroelectric dams located in the United States.

FERC: The Federal Energy Regulatory Commission.

Forced Outage Factor: The factor resulting from dividing the number of hours a generating unit or set of generating units is not synchronized to the grid system, not in reserve shutdown state and considered to be out of service for unplanned outages—or a startup failure, by the number of total hours in the period multiplied by 100% or a Program Administrator calculated equivalent forced outage factor that reflects the likelihood and extent to which a resource will be unavailable from time to time due to factors outside management control.

Forward Showing Program: The program and requirements as set forth in Part II of this Tariff.

Forward Showing Submittal ("FS Submittal"): The submissions a Participant is required to submit in advance of each Binding Season to demonstrate its satisfaction of the FS Capacity Requirement and FS Transmission Requirement, as set forth in Part II of this Tariff.

Forward Showing Year: A period consisting of a Summer Season and the immediately succeeding Winter Season.

FS Capacity Requirement: The minimum quantity of capacity a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

FS Deadline: The deadline for Participants' submissions of their FS Submittals for a Binding Season, as established under Part II of this Tariff.

FS Planning Reserve Margin ("FSPRM"): An increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, or lower availability of resources, expressed as a percentage of the applicable peak load forecast, as determined in accordance with Part II of this Tariff.

FS Transmission Requirement: The minimum quantity of transmission service rights a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

High-Priced Day: The most recent day in the CAISO in which prices in the day-ahead market were at least $200/MWh.

Holdback Capacity: Capacity that is voluntarily supplied or is the result of a positive Sharing Calculation result that is bindingly committed to the WRAP after it is claimed by one or more Participants with a negative Sharing Calculation result.

Holdback Requirement: A MW quantity, as determined on a Preschedule Day, that a Participant is required to be capable of converting into an Energy Deployment on a given hour of the succeeding Operating Day, as more fully set forth in Part III of this Tariff.

ICE Index: A wholesale electric price index prepared and published by the Intercontinental Exchange.

Incremental Cash Working Capital Support Charge: Incremental Cash Working Capital Support Charge shall have the meaning provided in Schedule 1 of this Tariff.

Independent Evaluator: An independent entity engaged to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications, as set forth in Part I of this Tariff.

Installed Capacity: Nameplate capacity adjusted for conditions at the site of installation.

International Power Marketing Entity: An entity that (i) owns, controls, purchases and/or sells resource adequacy supply and is responsible under the WRAP program for meeting LRE obligations associated with one or more loads physically located outside the United States.

Legacy Agreement: A power supply agreement entered into prior to October 1, 2021.

Load Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Load Charge Rate: Load Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Costs: Load Services Costs shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Cost Centers: Load Services Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Percentage: Load Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Load Responsible Entity ("LRE"): An LRE is an entity that (i) owns, controls, purchases and/or sells resource adequacy supply, or is a Federal Power Marketing Administration or an International Power Marketing Entity, and (ii) has full authority and capability, either through statute, rule, contract, or otherwise, to:

(a) submit capacity and system load data to the WRAP Program Operator at all hours;

(b) submit Interchange Schedules within the WRAP Region that are prepared in accordance with all NERC and WECC requirements, including providing E-Tags for all applicable energy delivery transactions pursuant to WECC practices and as required by the rules of the WRAP Operations Program;

(c) procure and reserve transmission service rights in support of the requirements of the WRAP Forward Showing Program and Operations Program; and

(d) track and bilaterally settle holdback and delivery transactions.

Subject to the above-mentioned criteria, an LRE may be a load serving entity, may act as an agent of a load serving entity or multiple load serving entities, or may otherwise be responsible for meeting LRE obligations under the WRAP.

Locational Marginal Price: The cost of delivering an additional unit of energy to a given node, as calculated under a FERC-regulated wholesale electric tariff.

Loss of Load Expectation ("LOLE"): An expression of the frequency with which a single event of failure, due to resource inadequacy, to serve firm load would be expected (based on accepted reliability planning analysis methods) to result from a given FS Planning Reserve Margin.

Make Whole Adjustment: A component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Maximum Base Charge: The maximum amount prescribed in Schedule 1 of the Tariff that the Base Charge cannot exceed.

Maximum Load Charge Rate: The maximum rate prescribed in Schedule 1 of the Tariff that the Load Charge Rate cannot exceed.

Median Monthly P50 Peak Loads: Median Monthly P50 Peak Loads has the meaning prescribed by Schedule 1 of this Tariff.

Month: A calendar month.

Monthly Capacity Deficiency: A Participant's Capacity Deficiency for a given Month.

Monthly Deficiency: An identification under Part II of this Tariff whether, and the extent to which, a Participant's need for capacity or transmission for a given Month is greater than the capacity or transmission, respectively, the Participant can demonstrate for such Month.

Monthly FS Capacity Requirement: FS Capacity Requirement determined as to a Month.

Monthly FSPRM: The FS Planning Reserve Margin applicable to a given Month of a given Binding Season, as determined in accordance with Part II of this Tariff.

Monthly Transmission Deficiency: A Participant's Transmission Deficiency for a given Month.

Monthly Transmission Demonstrated: A Participant's Demonstrated FS Transmission for a given Month.

Monthly Transmission Exceptions: Exceptions from the FS Transmission Requirement approved under Part II of this Tariff for a Participant for a given Month.

Multi-Day-Ahead Assessment: A period of days preceding each Operating Day, and ending on the Preschedule Day, during which Sharing Calculations are successively performed based in each case on Operating Day conditions expected at the time of calculation.

North American Electric Reliability Corporation ("NERC"): A not-for-profit international regulatory authority that serves as the designated electric reliability organization for the continental United States, Canada, and a portion of Mexico.

Net Contract QCC: The QCC, which may be a positive or negative value, calculated, in sum and on net, for a Participant's power purchase agreements and power sale agreements, in accordance with Part II of this Tariff.

Non-Binding Season: As to a Participant, *any* Binding Season during which the *provisions of Section 15A.1* of this Tariff *apply*.

Non-Binding Participant: For any Binding Season, a Participant that has made an election by which such Binding Season is a Non-Binding Season for that Participant.

Open Access Transmission Tariff: A governing document on file with FERC establishing the rates, terms, and conditions of open access transmission service, or equivalent tariff of a transmission service provider that is not required to file its transmission service tariff with FERC.

Operating Day: A current Day of actual electric service from resources to load, for which Sharing Events are determined and Energy Deployments may be required, as set forth in Part III of this Tariff.

Operations Program: The program and requirements set forth in Part III of this Tariff.

P50 Peak Load Forecast: A peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast.

Participant: A Load Responsible Entity that is a signatory to the WRAPA.

Portfolio QCC: As to a Participant, the sum of the Resource QCC provided by all of a Participant's Qualifying Resources plus the Net Contract QCC of such Participant, as adjusted to reflect RA Transfers as described in Section 16.2 7 and Planned Outages as described in Section 16.2.8.

Preschedule Day: The applicable scheduling Day for a given Operating Day as defined in scheduling calendar established by WECC.

Program Administrator: The Western Power Pool, in its role as the entity responsible for administering the WRAP.

Program Operator: A third party that has contracted with the Program Administrator to provide technical, analytical, and implementation support to the Program Administrator for the WRAP.

Program Review Committee ("PRC"): The stakeholder sector committee as established in Section 4.2 of this Tariff.

Pure Capacity: A MW quantity of capacity without any assigned forced outage rate employed in ELCC determinations under Part II of this Tariff.

Qualifying Capacity Contribution ("QCC"): The MW quantity of capacity provided by a resource, contract, or portfolio which qualifies to help satisfy a Participant's FS Capacity Requirement, as determined in accordance with Part II of this Tariff.

Qualifying Resource: A generation or load resource that meets the qualification and accreditation requirements established by and under Part II of this Tariff.

Real-Time Price: A price for wholesale electric transactions designated as a real-time price in an Applicable Price Index.

Resource Adequacy Participant Committee ("RAPC"): The committee comprised of representatives from each Participant as established in Part I of this Tariff.

Resource QCC: The QCC provided by a Qualifying Resource, as determined in accordance with Part II of this Tariff.

Run-of-River Qualifying Resource ("ROR"): A hydro-electric power project that does not have the capability to store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour. Resource does not meet the definition of a Storage Hydro Qualifying Resource.

Safety Margin: An additional factor allocated among Participants with positive sharing calculations when warranted by certain conditions as prescribed by Part III of this Tariff.

Senior Official Attestation: A signed statement of a senior official of a Participant attesting that it has reviewed such Participant's information submission required under this Tariff, that the statements therein are true, correct and complete to the best of such official's knowledge and belief following due inquiry appropriate to the reliability and resource adequacy matters addressed therein, and containing such further statements as required by this Tariff or the applicable Business Practice Manual for the information submission at issue.

Sharing Calculation: A calculation used in the Operations Program under Part III of this Tariff to identify any hour in which any Participant is forecast to have a capacity deficit.

Sharing Event: An hour or hours of an Operating Day for which one or more Participants has a negative Sharing Calculation result, as determined in accordance with Part III of this Tariff.

Storage Hydro Qualifying Resource: A hydro-electric power project with an impoundment or reservoir located immediately upstream of the powerhouse intake structures that can store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour or longer.

Subregion: An area definition approved by the Board of Directors and identified in the Business Practice Manuals, that is wholly contained within the WRAP Region, which is separated from one or more other Subregions by transmission constraints on capacity imports or on capacity exports that result, or are expected to result, in differing FSPRM determinations for that Subregion relative to such other Subregion.

Summer Season: A period of time that commences on June 1 of a Year and terminates on September 15 of the same Year.

System Sale: A bilateral agreement that conveys generating capacity from a group of generating resources from one party to another.

Transition Period: The Binding Seasons within the time period from June 1, 2025, through March 15, *2029*, plus the time period required to implement the requirements and procedures of Part II of this Tariff applicable to such Binding Seasons.

Transmission Deficiency: A shortfall in a Participant's demonstration of secured transmission service rights, after accounting for any approved transmission exceptions, relative to that Participant's FS Transmission Requirement, as further defined in Part II of this Tariff.

Unforced Capacity: The percentage of Installed Capacity available after a unit's forced outage rate is taken into account.

Variable Energy Resource ("VER"): An electric generation resource powered by a renewable energy source that cannot be stored by the facility owner or operator and that has variability that is beyond the control of the facility owner or operator, including but not limited to a solar or wind resource.

VER Zone: A geographic area delineated in accordance with Section 16.2.5.2 of this Tariff for a given type of VER, where each VER of that type located in such area is anticipated to be comparably affected by meteorological or other expected conditions in such area to a degree that warrants distinct calculation of ELCC allocations for such VERs of that type in such area.

Voluntary Holdback: Capacity that is offered to the Operations Program by a Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result, some or all of which can used as part of the offering Participant's Holdback Requirement. For a Participant in a Subregion without a Central Hub, Voluntary Holdback for an hour must additionally include a total quantity for all identified points from Section 19.4 at which it can deliver that is no less than the amount of the Voluntary Holdback capacity for such hour.

Western Electricity Coordinating Council ("WECC"): A non-profit corporation that has been approved by FERC as the regional entity for the western interconnection and that also has NERC delegated authority to create, monitor, and enforce reliability standards.

Western Resource Adequacy Program Agreement ("WRAPA"): The participation agreement for the Western Resource Adequacy Program, as set forth as Attachment A to this Tariff, or as set forth for an individual Participant in a non-conforming version of such participation agreement accepted by FERC.

Western Resource Adequacy Program ("WRAP"): The Western Resource Adequacy Program, as established under this Tariff.

Western Power Pool ("WPP"): Northwest Power Pool, d/b/a Western Power Pool, which serves as Program Administrator for the WRAP under this Tariff and holds exclusive rights under section 205 of the Federal Power Act to file amendments to this Tariff.

Winter Season: A period of time that commences on November 1 of a Year and terminates on March 15 of the immediately following Year.

WRAP Cost Assignment Matrix: The matrix set forth in Schedule 1 of this Tariff to identify which WRAP costs are assessed to the Base Charge and the Load Charge components of the WRAP Administration Charge.

WRAP Region: The area comprising, collectively, (i) the duly recognized and established load service areas of all loads in the United States that all Participants are responsible for serving, (ii) the duly recognized and established load service areas of all loads in the United States that all load serving entities, on whose behalf a Participant acts in accordance with this Tariff, are responsible for serving, and (iii) the applicable location(s) on the United States side of the United States

international border that form the basis for an International Power Marketing Entity's participation under the WRAP, in all cases excluding, for any Binding Season, any loads permitted by this Tariff to be excluded from Participants' Forward Showing Submittal for such Binding Season.

Year: A calendar year.

2. Role of Western Power Pool

2.1 WPP, acting under the direction of its Board of Directors, shall administer the WRAP as Program Administrator. Except as specified in Section 3 of this Tariff, WPP, as authorized by its Board of Directors, shall have the sole authority to submit to FERC amendments to the rates, terms, and conditions set forth in this Tariff under section 205 of the Federal Power Act, 16 U.S.C. § 824d. Nothing contained herein shall be construed as affecting in any way the right of any Participant or any other entity to apply to FERC for amendments to the rates, terms, and conditions contained herein under section 206 of the Federal Power Act, 16 U.S.C. § 824e, or any other applicable provision of that Act.

2.1.1 WPP president and staff shall support the Board of Directors in overseeing all aspects of the WRAP, including oversight and management of the Program Operator(s) in accordance with any Program Operator agreement(s) entered into by WPP under Section 2.2 of this Tariff.

2.1.2 WPP and its staff shall provide all legal, regulatory, and accounting support for the WRAP, including support for making filings with FERC as authorized by the Board of Directors.

2.1.3 WPP staff shall provide all logistical support necessary to facilitate implementation of the WRAP and specifically all logistical needs of the Board of Directors and reasonable logistical assistance to facilitate meetings and activities of the RAPC, PRC, and all subordinate organizational groups.

2.2 As Program Administrator, WPP shall undertake all actions as necessary to implement and administer the WRAP, including but not limited to engaging one or more Program Operator(s) to perform technical operations of the WRAP including both the Forward Showing Program and Operations Program. Except as otherwise provided herein, WPP may contract for certain activities required by this Tariff to be provided by one or more Program Operator(s) subject to oversight by the Board of Directors, provided, however, that the Program Operator shall operate solely as a contractor under the oversight of WPP, and WPP shall remain the sole point of compliance with this Tariff. WPP shall have the sole authority to enter into contracts for such engagements and is responsible for providing support and compensation for such Program Operator(s) pursuant to any contract(s).

2.2.1 WPP will contract with Program Operator(s) to assist WPP with providing reasonable technical support and expertise to all WRAP organizational groups as governed by the Program Operator’s contract with WPP.

3. Role of the Board of Directors and Limitations on Board Authority

3.1 Authority: Ultimate authority over all aspects of the WRAP as established under this Tariff shall be vested in the independent Board of Directors. Each member of the Board of Directors shall at all times exhibit financial independence from all Participants and classes of Participants, as further provided in the WPP Bylaws and policies. As set forth in Section 2.1 of this Tariff, the Board of Directors shall have the exclusive authority to approve and direct WPP to file amendments to this Tariff with FERC under section 205 of the Federal Power Act, 16 U.S.C. § 824d, subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff. The Board of Directors shall also have the exclusive authority to approve the Business Practice Manuals and any amendments to the Business Practice Manuals, subject to the terms, conditions, and limitations imposed under this Tariff.

3.2 The Board of Directors generally shall meet in open session for all matters related to the WRAP; however, the Board of Directors may meet in closed session as the chair deems necessary to safeguard the confidentiality of sensitive information, including but not limited to discussing matters related to personnel, litigation, or proprietary, confidential, or security sensitive information. The Board of Directors shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session. During open session, the chair of the Board of Directors will reasonably accommodate stakeholder requests to address the Board within the discretion of the chair.

3.3 The Board of Directors shall only consider amendments to this Tariff or the Business Practice Manuals after such amendments are first acted upon by the RAPC, subject to the following additional conditions:

3.3.1 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals, any stakeholder may appeal such decision to the Board of Directors, and the Board of Directors shall consider the appeal.

3.3.2 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals and a stakeholder has not appealed such decision, the Board of Directors may, on its own motion or motion of any member of the Board of Directors, consider the proposed amendment.

3.3.3 In the event that the COSR as a body opposes or appeals a RAPC decision to the Board of Directors regarding an amendment to this Tariff or the Business Practice Manuals, the process set forth in Section 4.3.3 of this Tariff shall apply prior to the Board of Directors' consideration of the RAPC decision.

3.3.4 In the event that the Board of Directors wishes to initiate an amendment to this Tariff or the Business Practice Manuals that has not undergone PRC

and RAPC review, the Board of Directors shall first submit such proposed amendment to the PRC for review under the processes set forth in Sections 4.1 and 4.2 of this Tariff.

3.3.5 Expedited Review Process: In the event that the RAPC determines that an expedited review process is necessitated by an exigent circumstance as set forth in Section 4.1.3.1.1 of this Tariff, the Board of Directors shall review the RAPC's recommended Tariff or Business Practice Manual amendment expeditiously and invite comment from the PRC, COSR, and stakeholders concurrently with its consideration of the RAPC proposal.

3.4 WPP is specifically prohibited from amending this Tariff to:

3.4.1 Alter, usurp, control, or otherwise materially modify the Participants' existing functional control and responsibility over their generation and transmission assets, including but not limited to planning and operation of such assets, Open Access Transmission Tariff administration, interfering with Balancing Authority duties and responsibilities, or imposing a must-offer requirement on any specific generation resources.

3.4.2 Administer Open Access Transmission Tariff service, engage in Balancing Authority operations, impose transmission planning requirements, or assume any transmission planning responsibilities with regard to any of the Participant's transmission assets.

3.4.3 Form any type of organized market, including but not limited to a capacity market, a regional transmission organization, a real-time market, or any other type of FERC-approved regional construct, unless such action is also approved by the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.4 Impose any requirements on Participants beyond the assessment of financial charges as specified in this Tariff or suspension or termination of participation for failure to meet any WRAP requirements.

3.4.5 Amend in any way this Section 3 of this Tariff without the approval of the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.6 Amend the RAPC voting thresholds set forth in Section 4.1.6 of this Tariff.

3.5 Subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff, if the Board of Directors votes to file at FERC to expand the WRAP to include market optimization or transmission planning services, WPP will initiate a formal process with COSR and other stakeholders to conduct a full review of governance structures and procedures, including the role of states. If COSR does not support any revised governance structure that emerges from such WPP review process, the WPP will file, along with any WPP governance proposal to FERC, an alternative

governance structure on behalf of the COSR so long as such COSR alternative governance structure is supported by 75% of the COSR.

4. Organizational Groups for the WRAP

4.1 Resource Adequacy Participants Committee

4.1.1 Authority and Purpose:

The RAPC shall be the highest level of authority for representation by Participants in the WRAP governance structure and shall represent the interests of Participants directly to the Board of Directors.

4.1.2 Composition:

The RAPC shall be composed of one representative from each Participant. Such representative shall be a senior management official with binding decision-making authority on behalf of the Participant, or a designated representative of a Participant's senior management official. A designated representative shall be required to have binding decision-making authority on behalf of the Participant and shall have all voting rights delegated from the senior management official. Participant shall appoint a designated representative no less than one Business Day in advance of a meeting for that designated representative to be eligible to vote during the meeting.

4.1.3 Functions:

The RAPC:

4.1.3.1

Shall consider and recommend that the Board of Directors approve or reject all proposed amendments to this Tariff or Business Practice Manuals prior to the Board of Directors considering such amendments, including any amendments reviewed and referred by the PRC.

4.1.3.1.1 Exigent Circumstances:

When the RAPC determines that an amendment to the Tariff or the Business Practice Manuals requires expedited Board of Directors review due to exigent circumstances, it may propose such amendment directly to the Board of Directors without awaiting review by other committees and stakeholders. Exigent circumstances include: (i) a FERC-mandated amendment to this Tariff or the Business Practice Manuals; (ii) an amendment to this Tariff or the Business Practice Manuals to address an immediate reliability impact; or (iii) an amendment to this Tariff or the Business Practice Manuals that the RAPC has determined has significant impacts to utility service.

4.1.3.2

Shall consider and vote to recommend that the Board of Directors approve or reject any proposed amendments to this Tariff or the Business Practice Manuals.

4.1.3.3

May provide input to the Board of Directors on any proposed WPP rules that apply both to the WRAP and other WPP services.

4.1.3.4 May evaluate and provide input to the Board of Directors on the WRAP administration budget and budget allocation to Participants, including amendments to the WRAP Administration Charge as calculated in accordance with Schedule 1 of this Tariff.

4.1.3.5 Shall form and organize all of the organizational groups under its responsibilities.

4.1.3.6 May take other actions reasonably related to its role as the senior-level Participant advisory committee to the Board of Directors regarding WRAP matters.

4.1.4 Leadership: The RAPC shall select from among its members a chair and vice chair.

4.1.5 Meetings:

4.1.5.1 Meetings of the RAPC will generally be open to all stakeholders. WPP shall provide advanced written notice of the date, time, place, and purpose of each RAPC meeting. All RAPC decisional items shall be placed on the open meeting agenda and allotted adequate time for public comment and deliberation.

4.1.5.1.1 The RAPC may meet in closed session as the RAPC chair deems necessary; provided, however, that the RAPC shall allow the designated COSR support staff member as specified in Section 4.3 of this Tariff to attend any closed meeting. The RAPC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.1.5.2 The quorum for a meeting of the RAPC or any organizational group organized under it shall be one-half of the representatives thereof, but not less than three representatives, provided that a lesser number may serve as a quorum for the sole purpose of voting to adjourn the meeting to a later time.

4.1.6 Voting:

4.1.6.1 Each RAPC representative shall have one vote.

4.1.6.2 Voting in the RAPC shall utilize a “House and Senate” model.

4.1.6.2.1 Each Participant’s “House” vote shall represent the proportion of the Participant’s Median Monthly P50 Peak Load, as described in Section 2 of Schedule 1 of this Tariff, compared to the sum of all Participants’ Median Monthly P50 Peak Loads. A Participant may choose to divide its

House vote but is responsible for announcing such at the time of voting.

4.1.6.2.2 Each Participant shall receive a single, non-weighted "Senate" vote.

4.1.6.2.3 For an action to be approved by the RAPC, it must pass both "House" and "Senate" votes as follows. For purposes of voting, the percentages identified below specify the percentage threshold of the entire RAPC (whether in attendance or not) that is needed for passage of an action.

4.1.6.2.3.1 Actions to amend any of the limitations on Board authority set forth in Section 3.4 of this Tariff require an 80% affirmative approval by both the House and the Senate vote tallies to be approved.

4.1.6.2.3.2 Actions brought before the RAPC that have been approved by the PRC require a 67% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.3.3 All other actions not specified in this Section 4.1.6.2.3 require a 75% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.4 If at any time a single Participant's P50 load for voting purposes would result in that Participant possessing a veto over any votes taken under Section 4.1.5.2.3, such Participant's House vote shall be capped at 1% below the amount that would convey such a veto, such that no single Participant will possess a veto over any action taken under Section 4.1.6.2.3.

4.2 Program Review Committee

4.2.1 Authority and Purpose: The PRC is a sector-representative group comprised in accordance with Section 4.2.2 of this Tariff. The PRC is responsible for receiving, considering, and proposing amendments to this Tariff and the Business Practice Manuals. The PRC shall serve as a clearinghouse of all recommended amendments to this Tariff or the Business Practice Manuals, except for those designated by the RAPC as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, amendments to Schedule 1 of this Tariff and cost allocation for the WRAP, and amendments to the WRAPA set forth as Attachment A of this Tariff. The PRC shall serve in an advisory capacity to the RAPC and, when applicable, the Board of Directors.

4.2.1.1 The PRC shall present all proposals received to the RAPC, along with the PRC's recommendation and summaries of all comments and feedback received.

4.2.1.2 The PRC's decisions are advisory-only and are not binding on the RAPC, the Board of Directors, or WPP.

4.2.2 Composition: The PRC shall be composed of up to twenty representatives from the following ten sectors: four representatives of RAPC Participant investor-owned utilities; four representatives of RAPC Participant publicly-owned (consumer or municipal) utilities; two representatives of RAPC Participant retail competition load serving entities; two representatives from RAPC Participant Federal Power Marketing Administrations; two representatives of independent power producers; two representatives of public interest organizations; one representative of retail consumer advocacy groups; one representative of industrial customer advocacy groups; one representative of load serving entities with loads in the WRAP that are represented by other LREs and are not otherwise eligible for any other sector; a representative from the COSR. Expectations for sectors to consider regional, operational, geographic, demographic, and other forms of diversity in selecting their sector representatives are set forth in more detail in the PRC charter, which shall be posted and maintained on the WRAP website or other appropriate public location.

4.2.3 The PRC shall establish a process and criteria for receiving and reviewing proposed amendments to this Tariff and the Business Practice Manuals. Such review will include procedures for stakeholder comment.

4.2.4 Meetings: The PRC shall meet primarily in open session; provided that the PRC may schedule closed meetings if it determines that doing so would be beneficial to safeguard the confidentiality of sensitive information. The PRC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.2.5 Voting: The PRC shall endeavor to operate by consensus. When voting is necessary, voting shall consist of one sector one vote, with an affirmative vote of six sectors (as specified in Section 4.2.2 of this Tariff) constituting approval of an action before the PRC.

4.2.5.1 For sectors with four seats, three sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.5.2 For sectors with two seats, both sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.6 Participants and other entities shall participate in no more than one PRC sector. If a Participant or other entity is eligible to participate in more than one sector, such Participant or other entity shall declare in which sector it will participate.

4.3 Committee of State Representatives

4.3.1. Composition: The COSR is a committee composed of one representative from each state or provincial jurisdiction (either public utility commission or state/provincial energy office) that regulates at least one Participant.

4.3.2 Leadership: The COSR shall determine its leadership, including a chair and vice chair. The chair or vice chair will be requested to attend all open sessions of the RAPC to provide input and advice.

4.3.2.1 The COSR shall designate a COSR support staff member to attend and audit closed meetings of the RAPC under a non-disclosure agreement.

4.3.3 Authority:

4.3.3.1 If the COSR determines that a proposal approved by the RAPC is substantially different from the proposal submitted to the RAPC by the PRC, the COSR may engage in additional public review and comment before the RAPC decision is presented to the Board of Directors; provided that this additional public review and comment does not unreasonably delay presentation to the Board of Directors.

4.3.3.2 If the COSR as a body opposes or appeals a RAPC decision to the Board of Directors, the Board of Directors will not consider the RAPC's decision until the RAPC engages with the COSR to discuss, in at least two public discussions, to attempt to reach a mutually agreeable solution.

4.3.3.2.1 If the appeal relates to an amendment that the RAPC designated as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, COSR can require no more than one public discussion, provided that such additional discussion does not unreasonably hinder the timeline for Board of Directors consideration of the proposed amendment.

4.3.4 Voting, Meetings, and Quorum: The COSR may develop its own rules governing voting, meetings, and quorum for action. COSR shall be responsible for its own costs.

5. Independent Evaluator

5.1 WPP shall engage an Independent Evaluator to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications. The Independent Evaluator shall report directly to the Board of Directors.

5.2 The Independent Evaluator shall conduct an annual review of the WRAP, including but not limited to analyzing prior year program performance, accounting and settlement, and program design.

5.3 The Independent Evaluator shall prepare an annual report of its findings, and any recommended modifications to WRAP design, and present its findings to the WRAP committees and the Board of Directors, subject to any necessary confidentiality considerations. Any data included in the Independent Evaluator's report shall be reported on an aggregated basis as applicable to preserve confidentiality. The Independent Evaluator's annual reports shall be available to the public, except to the extent they contain information designated as confidential under this Tariff, or information designated as confidential by the Independent Evaluator.

5.4 The Independent Evaluator shall not:

5.4.1 Evaluate individual Participants.

5.4.2 Possess any decision-making authority regarding the WRAP or design modifications.

5.4.3 Evaluate WPP's day-to-day operations of the WRAP (except as part of review of prior year program performance).

6. WPP Invoicing and Settlement

6.1 WPP shall be responsible for issuing invoices to, and collecting from, Participants all charges under Schedule 1 of this Tariff for recovery of all WPP costs associated with administering the WRAP.

6.2 WPP shall be responsible for invoicing, collecting, and (as applicable) distributing revenues from Deficiency Charges under Part II of this Tariff and Delivery Failure Charges under Part III of this Tariff.

6.3 Participants are not required to provide credit assurances to WPP to cover charges under Schedule 1 of this Tariff, Deficiency Charges under Part II of this Tariff, or Delivery Failure Charge under Part III of this Tariff.

6.4 Participants shall make full payment of all invoices rendered by WPP for which payment is required to WPP within thirty calendar days following the receipt of the WPP invoice, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Participant that fails to make full and timely payment to WPP of amounts owed upon expiration of the cure period specified in Section 6.4.1 of this Tariff will be in default.

6.4.1 If a Participant fails to make timely payment as required by Section 6.4, WPP shall so notify such Participant. The notified Participant may remedy such asserted breach by paying all amounts due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); provided, however, that any such payment may be subject to a reservation of rights, if any, to refer such matter to dispute resolution procedures under Section 9 of this Tariff. If the Participant has not remedied such asserted breach by 5:00 p.m. Pacific Prevailing Time on the second Business Day following WPP's issuance of a written notice of breach, then the Participant shall be in default.

6.4.2 In the event of a Participant's default under Section 6.4.1 of this Tariff, WPP in its discretion may pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims in the state and federal courts as well as under the United States Bankruptcy Code. After deducting any costs associated with pursuing such claims, any amounts recovered by WPP with respect to defaults for which there was a Default Allocation Assessment shall be distributed to the Participants who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Participant, as calculated pursuant to Section 6.4.3 of this Tariff. In addition to any amounts in default, the defaulting Participant shall be liable to WPP for all reasonable costs incurred in enforcing the defaulting Participant's obligations.

6.4.3 In the event of a Participant's default with respect to an invoice issued by WPP for charges under Schedule 1 of this Tariff, in order to ensure that WPP remains revenue neutral, the Board of Directors may assess against, and collect from, the Participants not in default a Default Allocation Assessment to recover the costs associated with the default. Such assessment shall in no way relieve the defaulting Participant of its obligations.

6.4.3.1 The Default Allocation Assessment shall be equal to:

(20% × (1/N) + (80% × (Participant Median Monthly P50 Peak Load / Sum Participants Median Monthly P50 Peak Load)

where:

N = the total number of Participants, calculated as of the date WPP declares a Participant in default.

Participant Median Monthly P50 Peak Load = for each Participant included in factor "N" above, the Participant's Median Monthly P50 Peak Load as determined in Section 2 of Schedule 1 of this Tariff, recalculated on the day the WPP declares a Participant in default.

All Participants Median Monthly P50 Peak Load = the sum of the Participant Median Monthly P50 Peak Load values for all Participants included in factor "N" above.

7. Credit Requirements and Settlement for Holdback and Delivered Energy

7.1 Credit and Settlement for Holdback and Delivered Energy: Settlement of holdback and delivered energy shall be completed bilaterally between Participants, subject to the following:

7.1.1 Neither WPP nor the Program Operator(s) shall take title to energy or be party to any settlement of holdback or delivered energy.

7.1.2 Participants shall establish credit with each other through one of the following mechanisms. Neither WPP nor the Program Operator(s) shall be involved in the calculation of credit or credit limits.

7.1.2.1 Establish credit directly with each Participant: Participants may establish credit directly with other Participants from whom they may receive delivered energy.

7.1.2.1.1 Such credit should be established in advance of the applicable season.

7.1.2.1.2 The amount of such credit and any credit limit shall be at the discretion of each Participant.

7.1.2.2 WPP shall conduct a competitive solicitation process to identify a third-party service provider to serve as central credit organization and clearing house for credit and settlement. Once such central credit organization is selected, Participants that have not already directly established credit with all other Participants under Section 7.2.2.1 of this Tariff shall establish credit with the central credit organization.

7.1.2.2.1 WPP will provide the central credit organization any Operations Program related information necessary for them to perform their obligations as set forth in the agreement between WPP and the central credit organization.

7.1.2.2.2 All costs associated with the central credit organization service shall be borne by Participants as established in the agreement between WPP and the central credit organization and either billed directly on a transactional basis or else recovered under Schedule 1 of this Tariff.

7.1.2.3 The obligation to arrange sufficient credit shall at all times be on the deficient Participant (i.e., a Participant with a negative sharing calculation in the Operations Program). If a deficient Participant has not made good faith and commercially reasonable efforts to

obtain sufficient credit with a delivering Participant, such delivering Participant shall so notify WPP and shall be excused from any obligation to deliver to such deficient Participant. Nothing in this Section 7 requires a Participant to violate its written risk or credit policy.

7.2 All settlement pricing calculated under this Tariff shall be final and no adjustments to settlement prices shall be allowed after the later of: (1) ninety Days after such settlement prices are posted by WPP; or (2) the final outcome of any dispute resolution process that is initiated by a Participant to dispute a settlement price pursuant to the Dispute Resolution Procedures set forth in Section 9 of this Tariff.

7.2.1 A Participant may invoke the Dispute Resolution Procedures set forth in Section 9 of this Tariff to address calculation errors in any settlement price, but may not invoke the Dispute Resolution Procedures to dispute data sources or to request the use of alternative data sources.

8. Force Majeure, Limitation of Liability, and Indemnification

8.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither WPP nor the Participant will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. Notwithstanding the foregoing, the physical inability to perform because of an event of Force Majeure shall not relieve the party of any financial obligations incurred under this Tariff or as a result of the Force Majeure event, unless, and to the extent, such financial obligation is waived or excused under provisions of Part II or Part III of this Tariff expressly providing for such waiver or excuse.

8.2 Limitation of Liability:

8.2.1 Neither WPP nor the Program Operator shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Participant, other entity owning a Qualifying Resource, third party, or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or Program Operator, in which case WPP shall only be liable for direct damages.

8.2.2 Neither WPP nor the Program Operator shall be liable for damages arising out of services provided under this Tariff or any agreement entered into hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency, or imperfection of service, occurring as a result of conditions or circumstances beyond the control of WPP, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to the domestic electric utility industry.

8.2.3 To the extent that a Participant or other person has a claim against WPP, the amount of any judgment or arbitration award on such claim entered in favor of such entity shall be limited to the value of WPP's assets. No party may seek to enforce any claims under this Tariff or any Agreements entered into

hereunder against the directors, managers, members, shareholders, officers, employees, or agents of WPP, or against the Program Operator, who shall have no personal liability for obligations of WPP by reason of their status as directors, managers, members, shareholders, officers, employees, or agents of WPP or by virtue of their status as Program Operator.

8.2.4 To the extent that WPP is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party as it relates to any services provided, acts, or omissions under this Tariff or any agreement entered into hereunder, WPP shall be allowed to recover any such amounts under Schedule 1 of this Tariff as part of the WRAP Administration Charge. Notwithstanding the foregoing, WPP shall be prohibited from recovering under this Tariff any costs associated with any damages, compensation, or indemnification costs that arise: (i) with regard to any acts or omissions that occur outside of this Tariff and any agreements entered into hereunder, or (ii) if a court of competent jurisdiction determines that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or the Program Operator.

8.2.5 A Participant's liability to another Participant under this Tariff for failure to comply with obligations under this Tariff shall be limited to any charges or payments calculated pursuant to this Tariff; provided, however, that nothing in this Section 8.2.5 shall limit or is intended to foreclose any Participant's liability that may arise under any bilateral agreements between Participants.

8.3 Indemnification: The Participants shall at all times indemnify, defend, and save WPP (and any of its Program Operator(s), agents, consultants, directors, officers, or employees) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties arising out of or resulting from the performance of activities under this Tariff by WPP, any Program Operator(s), or agents, consultants, directors, officers, or employees of WPP, except in cases of gross negligence or intentional wrongdoing by WPP or the Program Operator. WPP shall credit any proceeds from insurance or otherwise recovered from third parties to Participants who have paid to indemnify WPP under this Section 8.3.

8.4 Actions upon Unavailability of Program Operator(s): In the event that the Program Operator(s) become(s) unwilling, unable, or otherwise unavailable to perform contractual duties necessary for WPP to discharge its obligations under this Tariff and WPP’s agreement(s) with the Program Operator(s), WPP shall engage with Participants as soon as practicable to determine what actions to take, including but not limited to filing with FERC a request to waive one or more provisions of this Tariff up to and including immediate suspension of all rights and obligations under this Tariff until a replacement Program Operator(s) can assume all relevant Program Operator functions.

9. Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Subject to the limitations set forth in Section 7.2.1 of this Tariff, any dispute between a Participant and WPP under the Tariff (excluding amendments to the Tariff or to any agreement entered into under the Tariff, which shall be presented directly to the FERC for resolution) shall be referred to a designated senior representative of WPP and a senior representative of the Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon) by mutual agreement, such dispute shall then be referred to the chief executive officer or comparable executive of each party for resolution. In the event that the executives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

9.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the parties to the dispute. If the parties fail to agree upon a single arbitrator within ten days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable FERC regulations.

9.3 Arbitration Decisions: Unless otherwise agreed by the parties, the arbitrator(s) shall render a decision within ninety days of appointment and shall notify the parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and/or any agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the FERC if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (i) the cost of the arbitrator chosen by the party to sit on the three-member panel and one half of the

cost of the third arbitrator chosen; or (ii) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any person to file a complaint with the FERC under relevant provisions of the Federal Power Act or of WPP to file amendments to this Tariff under the relevant provisions of the Federal Power Act.

10. Treatment of Confidential and Commercially Sensitive Information of Participants

10.1 Terms: For purposes of this Section 10 only, the term "WPP" shall also include, as applicable, any directors, officers, employees, agents, or consultants of WPP, the Independent Evaluator established under Section 5 of this Tariff, and any central credit organization established under Section 7 of this Tariff. WPP shall be bound by the rights, obligations, and conditions set forth in this Section 10. For purposes of this Section 10, the term "Disclosing Entity" shall include any Participant that discloses information to WPP that the Disclosing Entity deems and identifies as confidential or commercially sensitive. WPP's collection and handling of non-Participant data shall be governed by separate non-disclosure agreements with such non-Participants.

10.2 Treatment of Confidential or Commercially Sensitive Information: WPP shall identify in the Business Practice Manuals categories of Participant-specific data and information received from Participants that shall be treated as confidential or commercially-sensitive, which WPP shall not disclose publicly or to any other Participant or other entity except as provided for in this Section 10. In addition, WPP shall maintain the confidentiality of all of the documents, data, and information provided to it by any Participant that such disclosing Participant deems and specifically identifies as confidential or commercially sensitive. Notwithstanding the foregoing, WPP need not keep confidential: (i) information that is publicly available or otherwise in the public domain; or (ii) information that is required to be disclosed under this Tariff or any applicable legal or regulatory requirement (subject to the procedures set forth in Section 10.4 of this Tariff).

10.2.1 WPP staff may develop and release publicly composite or aggregated data based upon Participant confidential or commercially sensitive information, provided that such composite or aggregated data cannot be used to identify or attribute a disclosing Participant's confidential or commercially sensitive data. Such release of composite or aggregated data shall be governed by the following process.

10.2.1.1 Prior to the initial release of such composite or aggregated data, WPP staff shall present the form and format of such data to each Participant whose confidential information or data will be used to create the composite or aggregated data. If any such Participant objects to the form and format as revealing or allowing for attribution of confidential or commercially sensitive Participant-specific data, WPP staff shall determine whether to modify the form and format or to retain the proposed form and format for release. If WPP staff elects to retain the proposed form and format, the Participant shall have the right to appeal to the RAPC and WPP staff shall be prohibited from releasing the composite or aggregated data in the proposed form and format until the Participant's appeal rights as specified in this Section 10.2.1

are exhausted.

10.2.1.2 If a Participant appeals a WPP staff decision regarding the form and format of composite or aggregated data to the RAPC, the RAPC shall consider whether the form and format reveals or allows for attribution of confidential or commercially sensitive Participant-specific data. If the RAPC determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format unless the Participant timely appeals the RAPC decision to the Board of Directors.

10.2.1.3 If a Participant appeals a RAPC decision regarding the form and format of composite or aggregated data to the Board of Directors, the Board of Directors shall consider whether the form and format is sufficient to protect against the release or attribution of confidential or commercially sensitive Participant-specific data. If the Board of Directors determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format.

10.2.1.4 Once a proposed form and format of composite or aggregated data is approved by the WPP staff and is not appealed or appeals are unsuccessful, such form and format may be used for all future disclosures of composite or aggregate information and no Participant may dispute such release. If WPP staff proposes to alter the form and format, including but not limited to changing the granularity of data, WPP staff shall be required to follow the process set forth in this Section 10.2.1 and Participants shall have the right to appeal such changes in form and format as set forth herein. Notwithstanding the foregoing, if the composition of Participants in the WRAP changes in such a way that the form and format of composite or aggregated data is no longer sufficient to protect against disclosure or attribution of confidential or commercially sensitive Participant-specific data, an aggrieved Participant shall have a one-time right to raise the issue promptly with WPP Staff for presentation to and review by the Board of Directors, and the Board of Directors in its sole discretion shall decide whether the change in composition results in the form and format of the composite or aggregated data becoming insufficient to

protect against the release or attribution of confidential or commercially sensitive Participant-specific data; provided, however, that if an aggrieved Participant does not raise its concerns with the Board of Directors promptly following the change in composition, such Participant shall have waived its right to contest the release of such composite or aggregated data.

10.2.2 Notwithstanding anything to the contrary in this Section 10.2, if the RAPC unanimously votes to disclose publicly any particular category of Participant-specific data, such data shall no longer be deemed confidential regardless of any such designation by a disclosing Participant, and this election shall be binding on any current and future Participants until such time as the RAPC votes unanimously to prohibit public release of such category of data. A list of the categories of Participant-specific data that the RAPC unanimously votes to make public shall be included in the Business Practice Manuals.

10.3 Access to Confidential or Commercially Sensitive Information: Except as otherwise provided in Section 10.2 of this Tariff, no Participant, entity owning a Qualifying Resource, or any third party shall have the right hereunder to receive from WPP or to otherwise obtain access to any documents, data or other information that has been identified as or deemed to be confidential or commercially sensitive under Section 10.2 of this Tariff by a disclosing Participant. The provisions of this Section 10.3 do not apply to WPP (including any Independent Evaluator, member of the Board of Directors, or any WPP officer, employee, agent, or consultant that requires access to confidential or commercially sensitive information); provided that access to Participant-specific confidential or commercially sensitive information shall be solely for the purpose of performing the duties or functions under this Tariff or otherwise advising or assisting WPP. WPP shall develop internal policies and controls governing the handling and protection of confidential or commercially sensitive Participant-specific data by members of the Board of Directors, officers, employees, agents, consultants, or any Independent Evaluator.

10.4 Exceptions: Notwithstanding anything in this Section 10 to the contrary:

10.4.1 If WPP is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 10, WPP may disclose such information; provided, however, that as soon as practicable after WPP learns of the disclosure requirement and prior to making such disclosure, WPP shall notify any affected disclosing Participant of the requirement and the terms thereof. Any such disclosing Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and WPP shall cooperate with such disclosing Participant to take all reasonable available steps to oppose

or otherwise minimize the disclosure of the information permitted by applicable legal and regulatory requirements. WPP shall further cooperate with such disclosing Participant to the extent reasonably practicable to obtain proprietary or confidential treatment of confidential or commercially sensitive information by the person to whom such information is disclosed prior to any such compelled disclosure.

10.4.2 WPP may disclose confidential or commercially sensitive information, without notice to any affected disclosing Participant(s), in the event that FERC, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC, WPP shall take action, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, to request that the information be treated by FERC as confidential and non-public and, if appropriate, as Critical Energy Infrastructure Information and that the information be withheld from public disclosure. WPP shall provide the requested information to FERC within the time provided for in the request for information. WPP shall notify any affected disclosing Participant(s) within a reasonable time after WPP is notified by FERC that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time WPP and any affected disclosing Participant may respond before such information would be made public.

10.5 Notwithstanding any efforts undertaken pursuant to Section 10.4 to prevent or limit the release of a Participant's confidential or commercially sensitive information, in the event that FERC or a court of competent jurisdiction orders or otherwise permits the public release of a Participant's confidential or commercially sensitive information, the affected Participant shall have a one-time right to elect to terminate its participation in the WRAP under the expedited termination provisions set out in Section 11.2 of the WRAPA.

10.6 WPP shall handle any information identified or deemed to be Controlled Unclassified Information/Critical Energy Infrastructure Information in accordance with FERC's regulations set forth at 18 C.F.R. § 388.113 and any applicable FERC policies or other regulations, including but not limited to restricting access to such information on a password-protected portion of WPP's website or similar precautions.

10.7 Nothing in this Section 10 is intended to limit a Participant's ability to disclose or release publicly its own confidential or commercially sensitive information or data, or to limit a Participant's ability to authorize WPP's disclosure of such material to a specified recipient.

11. Timing

11.1 In the event that any deadline specified in this Tariff shall fall on a day that is not a Business Day, the deadline shall be extended to the next Business Day.

12. Application and Registration

12.1 Any entity wishing to participate in the WRAP must submit an application and registration in accordance with the Business Practices Manuals and must execute the WRAPA as set forth in Attachment A of this Tariff, or a non-conforming version of such participation agreement that is approved by FERC for an individual Participant. Such application and registration must be submitted in accordance with the timelines set forth in the Business Practices Manuals in advance of the next Binding Season.

12.2 Each Participant must register all of its resources and loads, regardless of whether such resources will be used to satisfy the WRAP requirements and regardless of whether certain loads will be subject to the requirements of the WRAP. Participants may modify their registration of resources and loads in accordance with the timing procedures set forth in the Business Practices Manuals.

12.3 In the event that more than one Participant attempts to register the same resource or load, the following procedure will be used to assign the resource or load to a Participant:

12.3.1 If a Participant attempts to register a load or resource that has already been registered by a different Participant, the resource or load will remain registered by the original Participant registering the resource or load until such time as both Participants mutually inform WPP that a change to the registration is required.

12.3.2 If two or more Participants attempt to register the same resource or load during the same registration window, WPP shall request that the Participants determine among themselves the appropriate registration of the resource or load before that resource or load is included in the WRAP.

PART II FORWARD SHOWING PROGRAM

13. Overview

13.1 In the Forward Showing Program, as set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals, each Participant shall, in advance of each Binding Season, show as to such Binding Season: (i) the total capacity, referred to and defined herein as the FS Capacity Requirement, required by the provisions of this Tariff for such Binding Season for reliable service to the loads for which such Participant is responsible; (ii) the demonstration of capacity, referred to and defined herein as the Qualifying Capacity Contribution, or QCC, provided by the Qualifying Resources the Participant provides or procures to meet its FS Capacity Requirement; and (iii) at least the minimum level of firm transmission service, referred to and defined herein as the FS Transmission Requirement, needed for reliable delivery of the QCC of the Participant's Qualifying Resources from such resources to the loads for which the Participant is responsible.

13.2 As also set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals: (i) WPP shall, in advance of each Binding Season, review the Forward Showing Submittals of each Participant for such Binding Season; (ii) WPP shall identify to the Participant any deficiencies in the Participant's Portfolio QCC (whether as to contracts or directly owned or controlled resources) relative to the FS Capacity Requirement, and any deficiencies in the identified firm transmission service relative to the FS Transmission Requirement, within sixty days of the Forward Showing Submittal deadline; (iii) the Participant shall have an opportunity to cure such deficiencies, within sixty days of notification of deficiency; and (iv) if the Participant fails to cure all such deficiencies on or before the deadlines prescribed herein, the Participant shall be assessed a Forward Showing Deficiency Charge.

14. Forward Showing Program Process and Timeline

14.1 The Forward Showing Program has two Binding Seasons, defined as the Summer Season and the Winter Season. The Summer Season is the period beginning on June 1 of each Year and ending on September 15 of that same Year. The Winter Season is the period beginning on November 1 of each Year and ending on March 15 of the succeeding Year. This Tariff does not establish resource or showing obligations outside the periods defined by the Summer Season and Winter Season.

14.2 Each Participant shall submit its Forward Showing Submittals for each Month of each Binding Season, with all required supporting materials and information as detailed in the Business Practice Manuals, on or before the FS Deadline for the Binding Season. The FS Deadline for each Binding Season shall be seven months before the start of such Binding Season.

14.2.1 Forward Showing Submittal:

14.2.1.1 Absent the exception in Section 14.2.1.2, each Participant shall submit a separate Forward Showing Submittal for loads for which it is responsible if transmission constraints between areas where its loads are located, including, without limitation, when Participant is responsible for loads in more than one Subregion, prevent application, in the manner more fully described in the Business Practice Manuals, of Resource QCC or Net Contract QCC from one load area to the FS Capacity Requirement of another load area.

14.2.1.2 Notwithstanding Section 14.2.1.1, a Participant responsible for loads in two Subregions may submit for a given Month a single Forward Showing Submittal for such loads, and may employ for determination of its FS Capacity Requirement for such Month the lower of the two FSPRM values determined for the Subregions where its loads are located, if the Participant demonstrates in such Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, equal to the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast for such Month, with a point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. Each such showing shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

14.2.2 Each Participant's Forward Showing Submittal shall include a Senior Official Attestation.

14.3 The FSPRM values used in the Forward Showing Submittals for a Binding Season shall be those values approved by the Board of Directors as the culmination of an Advance Assessment process. No later than twelve months before the FS Deadline for each Binding Season, WPP will determine and post the recommended FSPRM for each Subregion for each Month of such Binding Season. Participants shall provide their load, resource and other information reasonably required to perform the analyses and calculations required for the Advance Assessment, in accordance with the Advance Assessment information submission details and schedule specified in the Business Practice Manuals. No later than nine months before the FS Deadline for such Binding Season, the Board of Directors shall take its final action regarding approval of the FSPRM values for each Month of such Binding Season.

14.3.1 In connection with an Advance Assessment process, or otherwise in connection with consideration of a change to the Business Practice Manuals, the Board of Directors may determine that designation of Subregions would encourage the relief, in whole or part, of transmission constraints on the transfer of capacity within the WRAP Region (whether through development or commitment of transmission, of Qualifying Resources, or by other means) to the benefit of the WRAP Region and the advancement of the objectives of the WRAP. Each such Subregion shall be identified in the Business Practice Manuals.

14.3.2 Any Participant may choose to offer in the Advance Assessment process transmission service rights owned or controlled by such Participant for firm delivery of capacity from one Subregion to another Subregion, for use by other Participants under the terms of Part III of this Tariff during any or all identified Months of the applicable Binding Season. Each such offer shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service. No Participant is obligated to offer any such transmission service rights in the Advance Assessment process, but any offer so made and not withdrawn before the deadline during the Advance Assessment process specified in the Business Practice Manuals shall be considered a binding offer of the identified transmission service rights which may not be withdrawn before the end of the last Day of the Month for which such transmission service is offered. WPP shall take account of such offered transmission service rights, along with other transmission deliverability reasonably anticipated to be available for use by Participants for WRAP purposes during the applicable Binding Season in its determination of the recommended FSPRM values for each Month of the

applicable Binding Season for the WRAP Region and for each affected Subregion.

14.4 No later than sixty Days after the FS Deadline for a Binding Season, WPP will (i) provide the values of the Participant's FS Capacity Requirement and FS Transmission Requirement for each Month of the Binding Season; (ii) affirm that the Portfolio QCC of such Participant for each Month of the Binding Season equals or exceeds the FS Capacity Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Capacity Requirement; and (iii) affirm that the Demonstrated FS Transmission plus approved Monthly Transmission Exceptions of such Participant for each Month of the Binding Season equals or exceeds the FS Transmission Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Transmission Requirement.

14.5 Within 120 Days after the FS Deadline, the Participant shall (i) submit revisions to its Forward Showing Submittal, including, without limitation, additions or revisions to the Participant's Resource QCC, Net Contract QCC, or Demonstrated FS Transmission; (ii) in order to fully cure all identified deficiencies and demonstrate that such Participant's Portfolio QCC for each Month of the Binding Season equals or exceeds its FS Capacity Requirement; and (iii) fully provide Demonstrated FS Transmission for each Month of the Binding Season that equals or exceeds its FS Transmission Requirement for the same Month of the Binding Season where WPP identified deficiencies.

14.5.1 Any Participant that fails to cure identified deficiencies in its Forward Showing Submittal within the period prescribed above shall be assessed a Deficiency Charge.

15. Transition Period

15.1 Except as specified in Section 15.1.1, the Binding Season beginning November 1, 2027, will be the first Binding Season for which all Participants will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity. Any Binding Season during the Transition Period occurring before November 1, 2027, shall be a Non-Binding Season, as specified in Section 15A of this Tariff.

15.1.1 No later than January 15, 2026, a Participant may elect the Binding Season beginning June 1, 2027, as the first Binding Season for which it will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity by providing written notice of its election.

15.2 Within two years prior to the start of the first Binding Season of the WRAP, a Participant who has elected to participate in the first Binding Season may request a vote of all Participants who have elected to participate in the first Binding Season to delay implementation of the first Binding Season for up to two Seasons. Delayed implementation of the first Binding Season shall be approved if 75% of the Participants who elected to participate in the first Binding Season vote in favor of such delay, with approval requiring a vote of 75% of both the House and Senate vote tallies (as described in Sections 4.1.6.2.1 and 4.1.6.2.2 of this Tariff) of all Participants who elected to participate in the first Binding Season.

15.2.1 The deferral vote may only occur for the first Binding Season of the WRAP. If the Participants who elected to participate in the first Binding Season of the WRAP vote to delay implementation of the first Binding Season, all compliance charges for the Forward Showing Program and Operations Program are automatically deferred; except that the Participants may vote to delay implementation only of the Operations Program portion of the first Binding Season and retain the binding Forward Showing Program portion of the first Binding Season.

15A. Non-Binding Seasons

15A.1 A Participant will participate as a Non-Binding Participant for certain Binding Seasons in the Transition Period, as detailed in Section 15.1 of this Tariff, and when Critical Mass is not achieved for a given Binding Season, as detailed in Section 15A.2 of this Tariff. As to a Non-Binding Season, the Participant:

15A.1.1 Shall not be subject to Deficiency Charges, Transmission Deficiency Charges, Holdback Requirements, Energy Deployment obligations, or Delivery Failure Charges;

15A.1.2 Shall submit Forward Showing Submittals but shall not be required to cure deficiencies;

15A.1.3 Shall not have a mandatory Holdback Requirement as a result of the Sharing Calculation;

15A.1.4 May only receive Holdback Capacity offered voluntarily by other Participants in accordance with Part III of this Tariff; and

15A.1.5 Shall have all rights and be subject to all obligations under Part I of this Tariff and the Participant's WRAPA, including, without limitation, voting rights, committee participation, and the obligation to pay the WRAP Administration Charge.

15A.2 Once WPP has given notice to Participants that their Subregion does not have Critical Mass for a given Binding Season, each such Participant will have 30 days to provide notice to WPP if it intends to participate as a Non-Binding Participant for that Binding Season. Such notice and election will be given similarly for each season without Critical Mass participation.

16. Components of the Forward Showing

16.1 FS Capacity Requirement. The FS Capacity Requirement shall be determined for each Participant on a monthly basis by applying the applicable Monthly FSPRM for a Month to such Participant's peak load forecast for that Month. The Participant's peak load forecast for a given Month of a Binding Season will be the P50 Peak Load Forecast for the Binding Season multiplied by a shaping factor based on the historical relationship, for such Participant, of the seasonal peak for the Winter Season or Summer Season, as applicable, and the monthly peaks for the Months in such season, as more fully described in the Business Practice Manuals.

16.1.1 P50 Peak Load Forecast. The P50 Peak Load Forecast is a peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast. The Business Practice Manuals shall specify an approved load forecasting methodology for use by all Participants for their WRAP-required load forecasts which shall include (i) a base monthly peak derived from a recent historical period that recognizes additions and removals of load during the historical period, (ii) adjustments for known additions and removals of load during the forecast window; and (iii) a specified load growth factor.

16.1.2 FS Planning Reserve Margin

16.1.2.1 The FSPRM is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, expressed as a percentage of the applicable peak load forecast. The FSPRM shall be determined based on probabilistic analysis, taking account of uncertainties in generation and load, as the margin above peak load that provides an expectation of no more than a single event-day of loss of load in ten years (sometimes referred to herein as the "1-in-10 LOLE") for each Binding Season. The FSPRM shall be determined in a manner that accounts for the governing principles of QCC value determinations set forth in Section 16.2.5 of this Tariff and shall employ the applicable peak load for the applicable Binding Season and Months. Additional details, assumptions, methodologies, and procedures for determination of the FSPRM shall be as set forth in the Business Practice Manuals.

16.1.2.2 WPP shall calculate in the Advance Assessment process the recommended Monthly FSPRM for each Month of each Binding Season, for approval by the Board of Directors as set forth in this Part II.

16.1.2.3 The FSPRM shall employ (i) a simulated resource stack using capacity accreditation principles consistent with those used for WRAP QCC determinations; (ii) an adjustment in the total WRAP-required QCC value as needed to meet a 1-in-10 LOLE for each Binding Season, and (iii) while maintaining the 1-in-10 LOLE for each Binding Season in (ii), include a monthly reduction of capacity to ensure that each Month has at least 0.01 annual LOLE. The FSPRM for a Month shall be the simulated QCC as adjusted to meet the 1-in-10 LOLE for each Binding Season minus the P50 Peak Load Forecast for the Month, divided by the P50 Peak Load Forecast for the Month.

16.1.2.4 The FSPRM shall include an approximation of Contingency Reserves as set forth in the Business Practice Manuals.

16.1.3 Contingency Reserves Adjustment. A Participant's FS Capacity Requirement will be adjusted as set forth in the Business Practice Manuals to account for changes in Contingency Reserve requirements resulting from energy contract purchases and contract sales.

16.1.4 A Participant responsible for loads located in a Subregion for which an FSPRM value has been determined that is higher than the FSPRM value determined for a different Subregion may, in lieu of demonstrating a MW increment of Portfolio QCC otherwise required to satisfy such Participant's FS Capacity Requirement for a given Month, demonstrate in its Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, that is no greater than the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast, with the point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. The MW quantity of the additional transmission so demonstrated shall reduce for such Month, by the same MW quantity, the Portfolio QCC the Participant would otherwise be required to demonstrate to satisfy its FS Capacity Requirement for such Month. Each such demonstration shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

16.2 Qualified Capacity Contribution

16.2.1 For each Participant and each Binding Season, the Forward Showing shall show and support the Portfolio QCC, which shall be the sum of the QCC of the Participant's Qualifying Resources ("Resource QCC"), the QCC of its

contracted capacity ("Net Contract QCC"), and any transfers of capacity already accredited by another Participant ("Total RA Transfer," which could be positive or negative). The Portfolio QCC effective for a Binding Season shall be the value determined by WPP.

16.2.2 A resource will not be assigned a Resource QCC or counted toward Portfolio QCC unless it is a Qualifying Resource. Qualifying Resources are those that, before they are included in a Forward Showing Submittal, are first registered with WPP. A Participant seeking registration of a resource must submit a request for registration providing the resource information described in the Business Practice Manuals.

16.2.3 The minimum resource size for registration of a resource is 1 MW, provided, however, that Participants with responsibility for individual resources of less than 1 MW may aggregate them to meet the 1 MW minimum requirement, under the conditions and limitations specified in the Business Practice Manuals.

16.2.4 A Participant may include in its Forward Showing Submittal a request for an exception from its FS Capacity Requirement for an insufficiency of its Portfolio QCC solely due to (i) a catastrophic failure of one or more Qualifying Resources due to an event of Force Majeure as defined by Section 8.1 of this Tariff that (ii) the Participant is unable to replace on commercially reasonable terms prior to the FS Deadline as a result of the timing and magnitude of such catastrophic failure and its consequences. As more fully set forth in the Business Practice Manuals, such exception request shall be supported by a Senior Official Attestation. The exception request must include complete information on the nature, causes and consequences of the catastrophic failure, and must describe the Participant's specific, concrete efforts prior to the FS Deadline to secure replacement Qualifying Resources for the applicable Binding Season. WPP will consider the exception criteria established by this section, the information provided in the exception request, the completeness of the exception request, and other relevant data and information, in determining whether to grant or deny an FS Capacity Requirement exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such FS Capacity Requirement exception request. A Participant granted an exception hereunder must complete a monthly exception check report demonstrating that either the circumstances necessitating the exception have not changed; or that Qualifying Resources have become available, and the Participant has acquired them and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In

such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals.

16.2.5 QCC: WPP shall determine QCC values for the resource types specified below in accordance with the governing principles specified below for each resource type, and consistent with further details specified for each resource type in the Business Practice Manuals.

16.2.5.1 For resources that use conventional thermal fuels, including but not limited to, coal, natural gas, nuclear, and biofuel, WPP will determine QCC based on an Unforced Capacity methodology that employs resource-specific capability testing and capability requirements to determine an Installed Capacity value, and a forced outage calculation methodology based on historical performance during Capacity Critical Hours over a specified multi-year period (excluding outages properly reported as "outside management control"), or based on class-average forced outage data, as specified in the Business Practice Manuals, if there is insufficient data on historical performance.

16.2.5.2 For resources that are Variable Energy Resources, including, but not limited to, wind and solar resources, WPP will determine QCC based on an ELCC methodology, that accounts for synergistic portfolio effects within and among VER types at different resource penetration levels that influence the extent to which the WRAP Region can rely on those VER categories to meet overall capacity needs.

16.2.5.2.1 For such purpose, a separate ELCC value will be calculated in the aggregate for all VER resources of a given type in an identified VER Zone, to be delineated in the Business Practice Manuals based on factors such as geography, performance, meteorological considerations, and penetration.

16.2.5.2.2 As more fully described in the Business Practice Manuals, the zonal aggregate VER-resource-type value will be calculated by (i) conducting a benchmark LOLE study that includes all resource types except the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until,

respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; (ii) conducting an LOLE study that includes all resource types including the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until, respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; and (iii) subtracting the Pure Capacity value determined under subpart (ii) from the Pure Capacity value determined under subpart (i) (for which calculation a Pure Capacity value subtracted from each hour in either subpart (i) or subpart (ii) will be assigned a negative value; (iv) repeating steps (i) through (iii) for each Binding Season of the study period employing historical, or as necessary, synthesized, data; and (v) basing the aggregate value of the studied VER resource type for the studied VER Zone on the results of the calculation in step (iii) for the Binding Seasons studied, which may include differential weighting of the Binding Seasons studied as appropriate to improve the quality and predictive capacity of the final result.

16.2.5.2.3 The aggregate capacity calculated for each VER resource type in each VER Zone will then be allocated to VERs of that type in that VER Zone based on each such resource's average historical performance if at least three years of historical performance or three years of synthesized forecast data during the WRAP Region's CCH is available at the time of such allocation. If three years historical performance or synthesized forecast data is not then available, the average ELCC from the VER Zone will be assigned.

16.2.5.3 For resources that are Energy Storage Resources, WPP will determine QCC based on an ELCC methodology comparable to that used for VERs. The ELCC methodology will model Energy Storage Resources at the level of their usable capacity that can

be sustained for a minimum duration of four hours. An Energy Storage Resource need not have a nameplate rating that assumes a minimum of four hours in order to receive a QCC determination, but the QCC in that case will be scaled to reflect the capability that can be sustained for four hours, as more fully described in the Business Practice Manuals.

16.2.5.4 A Participant's Demand Response used as a Demand Response Capacity Resource must be controllable and dispatchable by the Participant or by the host utility, and must have met certain testing requirements consistent with Business Practice Manuals. WPP will determine Demand Response Load Modifier QCC by multiplying the load reduction in MWs by the number of hours the resource can demonstrate load reduction capability (for a period of up to five continuous hours) divided by five. The effects of Demand Response used as a Demand Response Capacity Resource must not be included in load provided for a Participant's Advance Assessment.

16.2.5.5 For Storage Hydro Qualifying Resources, the Participant will calculate a QCC based on a methodology detailed in the Business Practice Manuals that: (i) considers each resource's actual generation output, residual generating capability, water in storage, reservoir levels, and flow or project constraints over the previous ten-year historical period; (ii) determines the project's QCC by assessing the historical generation during CCHs on any given day and ability to increase generation during CCHs on the same day, subject to useable water in storage, inflows/outflows, and expected project operating parameters/constraints and limitations; (iii) incorporates forced outage rates; and (iv) determines QCC as average contribution to the CCH for each Winter Season and Summer Season over the previous ten years. If ten years of historical data is not available for the Storage Hydro Qualifying Resource, the Participant may alternatively employ data on the same metrics from a demonstrably comparable facility or apply another method that provides reasonable confidence in the reliability of the predicted values, as more fully set forth in the Business Practice Manuals. The Participant's QCC calculation shall be subject to review and validation by WPP. In connection with such review, the Participant shall provide WPP with the following information necessary to calculate a QCC for Storage Hydro Qualifying Resources: (i.a) historical reservoir elevation levels; (ii.a) historical plant generation; (iii.a) elevation versus capacity curves; (iv.a) any minimum or maximum reservoir level constraints; (v.a) forced outage rates; (vi.a) volume of water

versus reservoir elevation storage tables; and (vii.a) turbine discharge versus generation efficiency curve.

16.2.5.6 For Run of River Qualifying Resources, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals

16.2.5.7 For resources that (i) are not within the meaning of any of Sections 16.2.5.1 through 16.2.5.5, and that (ii) either (a) are not dispatchable; or (b) require the purchaser of energy from the resource to take energy as available from such resource, including but not limited to a qualifying facility as defined under the Public Utility Regulatory Policies Act of 1978, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals.

16.2.6 Net Contract QCC: WPP shall determine Net Contract QCC for the agreement types specified below in accordance with the governing principles specified below for each agreement type, and consistent with further details specified for each agreement type in the Business Practice Manuals. Net Contract QCC may be either positive or negative, to take account of, for example, a Participant's agreements for the sale of capacity to any other party.

16.2.6.1 Absent one of the exceptions described and limited below, capacity supply agreements qualifying for a Net Contract QCC in the WRAP must be resource specific, and therefore must include, among other requirements, an identified source, an assurance that the capacity is not used for another entity's resource adequacy requirements, an assurance that the seller will not fail to deliver in order to meet other supply obligations, and affirmation of NERC Priority 6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. The specific resources identified in a capacity supply agreement qualifying for Net Contract QCC shall meet the same Resource QCC accreditation requirements for the given resource type, as specified in Section 16.2.5.

16.2.6.2 A system sales contract can qualify for a Net Contract QCC value, provided that if the seller is not a Participant, the system capacity that is the subject of the agreement must be deemed surplus to the seller's estimated needs, there must be an assurance that the seller will not fail to deliver in order to meet other commercial obligations, and there must be NERC Priority

6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. Surplus status may be demonstrated by a Senior Official Attestation with pertinent supporting details for such surplus status, including written assent of the non-Participant Seller, secured by the purchasing Participant. Such attestation is not required if the seller is a Participant, because the information needed to verify surplus status is already available.

16.2.6.3 A supply agreement entered into prior to October 1, 2021 ("Legacy Agreement") can qualify for a Net Contract QCC value; provided that where a legacy agreement does not identify the source, it must be possible for WPP to presume a source or sources for the contract, including with the written assent of the supplier under such Legacy Agreement, conveyed in the form and manner set forth in the Business Practice Manuals. A Legacy Agreement for which such resource determination cannot be reasonably made will not be counted as adding to the Portfolio QCC.

16.2.7 Total RA Transfer: A Participant may agree with another Participant on a transfer of a portion of its Portfolio QCC to meet the other's FS Capacity Requirement ("RA Transfer"), provided that the details and duration of such transfer are reported to WPP for validation in accordance with procedures and information requirements specified in the Business Practice Manuals. Where such transfers have been duly reported and validated, an RA Transfer will be added to the purchasing Participant's Portfolio QCC and subtracted from the selling Participant's Portfolio QCC.

16.2.8 Planned Outages: Participants shall include in their Forward Showing Submittal for a Binding Season information on all Qualifying Resources that are currently out of service with a scheduled return date that falls during the Binding Season or after the Binding Season. Capacity associated with such resources must be deducted from Participants' Portfolio QCC as specified in the Business Practice Manuals to ensure no credit is granted for such resources during the planned outage. The aggregate of any additional outages that are planned to occur during the Binding Season but have not yet begun at the time of submission must be within the Participant's remaining surplus (or replaced with other supply). Participants may provide information on all Qualifying Resources that are planned to be out of service but if such data cannot be supplied with reasonable specificity, a Participant may provide a Senior Official Attestation at the time of the submission of its FS Submittal that it expects the sum of planned outages to be equal to or less than the surplus stated in its FS Submittal throughout the Binding Season.

16.2.8.1 If a Qualifying Resource is planned to return to service within the first five days of a Binding Season, WPP may approve a qualified acceptance of the FS Submittal, provided the deficiency is less than 500 MW.

16.2.8.2 A planned outage shall not justify a waiver of or exception to a Participant's holdback or energy delivery obligations under Part III of this Tariff. Participants will be expected to procure the necessary capacity or energy to meet the Operations Program requirements, regardless of planned outage schedules or FS Submittal acceptance.

16.3 FS Transmission Requirement

16.3.1 As part of its Forward Showing Submittal for a Binding Season, each Participant must demonstrate, as specified in the Business Practice Manuals, that it has secured firm transmission service rights, including under supply arrangements with a third party that holds or has committed transmission service rights, sufficient to deliver a MW quantity equal to at least 75% of the MW quantity of its FS Capacity Requirement. To the extent a Participant holds transmission service rights with a point of receipt at a Qualifying Resource, or in connection with an RA Transfer to such Participant, any such rights from such point in a MW quantity, respectively, in excess of the QCC of such Qualifying Resource, or in excess of the value of such RA Transfer, shall not contribute toward satisfaction of such Participant's FS Transmission Requirement. The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load. Notwithstanding the foregoing, authorized use of Capacity Benefit Margin will satisfy the FS Transmission Requirement. Demonstration of the FS Transmission Requirement shall not, in and of itself, relieve any Participant of responsibility for a Delivery Failure Charge as determined under Section 20.7 if such Participant's failure to obtain or maintain firm transmission service of the type and quantity expected by the Operations Program, as described in Section 20.6 of this Tariff, caused or contributed to an Energy Delivery Failure.

16.3.2 A Participant may include in its Forward Showing Submittal a request for an exception from a limited part of its FS Transmission Requirement, provided the exception request meets the terms, conditions, and limitations of one or more of the following four exception categories below. As more fully set forth in the Business Practice Manuals, such exceptions may be subject to overall WRAP limits, and shall be supported by a Senior Official Attestation. WPP will consider the exception category terms, conditions and limitations set forth below, and may consider the completeness of the

exception request, information from transmission service providers, OASIS data, and data readily available to WPP from other reliable and validated sources concerning the duration, timing, firmness and quantity of available transmission service or equivalent options (including transmission construction), in determining whether to grant or deny a transmission exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such transmission exception request. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals. A Participant granted a transmission exception under either Section 16.3.2.1 or Section 16.3.2.2 must complete a monthly transmission exception check report demonstrating that either (i) the circumstances necessitating the exception have not changed; (ii) transmission has become available and the Participant has acquired it; or (iii) the Participant has acquired a different resource, and associated transmission service rights, and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance.

16.3.2.1 Enduring Constraints. Participant is unable to demonstrate sufficient NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights on any single segment of a source to sink path for a Qualifying Resource; and Participant demonstrates that no ATC for such transmission service rights is available (either from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less; and Participant submits a Senior Official Attestation that Participant has taken commercially reasonable efforts to procure firm transmission service rights, and that Participant has posted Firm Transmission Requirements on a relevant bulletin board prior to the FS Deadline. In the event such transmission service rights are only available for a duration of more than one year (whether from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Enduring Constraints exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify

for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. In addition to the foregoing, Participant must further demonstrate that there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all CCHs in the same season of the most recent year for which CCHs have been calculated; or, if the path was constrained in at least one CCH of the CCHs in the same season of the most recent year for which CCHs have been calculated, Participant in that case must demonstrate either that it is constructing or contracting for a new local resource for at least the amount of the exception requested, or that it is pursuing long-term firm transmission service rights by entering the long-term queue and taking all appropriate steps to obtain at least the amount of the exception requested.

16.3.2.2 Future Firm ATC Expected. Participant demonstrates that ATC for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not posted or available prior to the FS Deadline (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less, and that the transmission service provider has, after the FS Deadline, released additional ATC for such transmission service rights in every one of the CCHs of the most recent year for which CCHs have been calculated on the applicable path. In the event ATC for such transmission service rights is only posted or available prior to the FS Deadline for a duration of more than one year (whether from the transmission service provider or through a secondary market) on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Future Firm ATC Expected exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. The Participant must also demonstrate that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.3 Transmission Outages and Derates. Participant demonstrates that an applicable segment of its existing transmission service rights from its source to sink path for its Qualifying Resource is expected to be derated or out-of-service and the ATC

for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not otherwise available, and that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.4 Counterflow of a Qualifying Resource. Participant demonstrates that either: (i) Participant's use of firm transmission service in connection with the delivery of capacity from Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to Participant's load (or other qualifying delivery point permitted by the WRAP) or (ii) a second Participant's use of firm transmission service in connection with the delivery of capacity from the second Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the second Participant's load (or other qualifying delivery point permitted by the WRAP) provides a direct and proportional counterflow transmission that supports the first Participant's delivery of capacity from the first Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the first Participant's load (or other qualifying delivery point permitted by the WRAP) Qualifying Resource to their load. If the exception is requested under subpart (ii) of this subsection, the Participant requesting the exception shall include a written acknowledgement from the second Participant that it is aware of such exception request.

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16.3.3 To the extent a Participant does not demonstrate satisfaction of its FS Transmission Requirement by the FS Deadline, the Participant may correct any such deficiency on or before the end of the cure period prescribed by Section 14.5 of this Tariff to avoid a Deficiency Charge.

16.3.4. Any deficiency of transmission service rights ultimately determined by WPP will be treated, for purposes of Deficiency Charge determinations, as in conjunction with, and not additive to, any deficiencies of QCC determined pursuant to Section 16.2.

17. Forward Showing Deficiency Charge

17.1 If a Participant fails during the cure period to demonstrate that it has resolved any identified deficiencies in either or both of its FS Capacity Requirement and its FS Transmission Requirement, the Participant will be assessed a Deficiency Charge for each Month for which a deficiency is identified in accordance with this section. In such case, the deficiency for which the Participant will be assessed a Deficiency Charge will be calculated in accordance with the following:

Participant's Monthly Capacity Deficiency = Maximum of (Monthly FS Capacity Requirement – Monthly Portfolio QCC, 0)

Participant's Monthly Transmission Deficiency (MW) = Maximum of ((75% × Monthly FS Capacity Requirement) – (Monthly Transmission Demonstrated + Approved Monthly Transmission Exemptions), 0)

Where Monthly Transmission Demonstrated is the amount of transmission service rights submitted by a Participant per the requirements in Section 16.3 and validated by WPP for each month.

Monthly Deficiency (MW) = Maximum of (Monthly Capacity Deficiency, Monthly Transmission Deficiency)

17.2 A Participant's Deficiency Charges shall be calculated as set forth in this Section 17.2, subject to the Transition Period rules in Section 17.3, and shall take account of multiple Monthly Deficiencies within a Forward Showing for a single Binding Season, multiple Deficiencies across a Forward Showing Year, consisting of a Summer Season and the immediately succeeding Winter Season, and any Monthly Deficiencies in a previous Forward Showing Year, in accordance with the following:

17.2.1 The Monthly Deficiency with the highest MW value in a Forward Showing for a Summer Season shall be assessed a Deficiency Charge equal to:

Max Summer Deficiency (MW) × Annual CONE ($/kW-year) × 1000 × Summer Season Annual CONE Factor

17.2.2 Any other Monthly Deficiency in the Participant's Forward Showing for the same Summer Season shall be assessed a Deficiency Charge equal to:

Additional Summer Deficiency (MW) × (Annual CONE ($/kW-year)/12) × 1000 × 200%

17.2.3 Any Monthly Deficiency in the Forward Showing for the immediately succeeding Winter Season with a higher MW value than the highest MW value of the Monthly Deficiency in the Summer Season shall be assessed a Deficiency Charge on the incremental MW value above the Summer Season equal to:

Maximum of (Max Winter Deficiency – Max Summer Deficiency, 0) (MW) × Annual CONE ($/kW-year) × 1000 × Winter Season Annual CONE Factor

and in such case where there is a Monthly Deficiency in the Winter Season with a higher MW value than the highest MW value of any Monthly Deficiency in the Summer Season, the Monthly Deficiency with the highest MW value in the Summer Season shall be assessed an additional Deficiency Charge calculated in accordance with Section 17.2.2.

17.2.4 Any other Monthly Deficiency in the Participant's Forward Showing Submittal for the same Winter Season shall be assessed a Deficiency Charge equal to:

Additional Winter Capacity Deficiency × (Annual CONE/12) × 1000 × 200%

17.2.5 For purposes of the above, CONE is the estimated cost of new entry of a new peaking natural gas-fired generation facility. The CONE estimate shall be based on publicly available information relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE estimate shall not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services from the hypothetical facility, nor shall it consider variable operating costs necessary for generating energy.

17.2.6 WPP shall review the CONE estimate annually for a possible update. Any proposed changes in the CONE estimate shall be subject to review through the stakeholder process for program rule changes.

17.2.7 The Summer Season Annual CONE Factor shall vary based on the ratio ("Summer % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Summer Season, divided by the P50 Peak Load Forecast for the Summer Season, as follows:

If the Summer % Deficit is less than or equal to 1%, the Summer Season Annual CONE Factor = 125%

If the Summer % Deficit is greater than 1% but less than or equal to 2%, the Summer Season Annual CONE Factor = 150%

If the Summer % Deficit is greater than 2% but less than or equal to 3%, the Summer Season Annual CONE Factor = 175%

If the Summer % Deficit is greater than 3%, the Summer Season Annual CONE Factor = 200%

17.2.8 The Winter Season Annual CONE Factor shall vary based on the ratio ("Winter % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Winter Season, divided by the P50 Peak Load Forecast for the Winter Season, as follows:

If the Winter % Deficit is less than or equal to 1%, the Winter Season Annual CONE Factor = 125%

If the Winter % Deficit is greater than 1% but less than or equal to 2%, the Winter Season Annual CONE Factor = 150%

If the Winter % Deficit is greater than 2% but less than or equal to 3%, the Winter Season Annual CONE Factor = 175%

If the Winter % Deficit is greater than 3%, the Winter Season Annual CONE Factor = 200%

17.2.9 Notwithstanding Sections 17.2.7 and 17.2.8, if a *Participant incurred any FS Deficiency Charges* in a Forward Showing Year *after the Transition Period*, then for the immediately following Forward Showing Year, both the Summer Season Annual CONE Factor and the Winter Season Annual CONE Factor shall be 200% *for such Participant*.

17.2.10. Subject to the Transition Period rules in Section *15A.1*, revenues from the payment of Deficiency Charges as to a Binding Season shall be allocated among those Participants with no Deficiency Charges for that Binding Season, pro rata based on each Participant's share of all such Participants' Median Monthly P50 Peak Loads for such Binding Season.

17.3 During the Transition Period, Deficiency Charges otherwise calculated under Section 17.2 shall be reduced as, when, and to the extent, and subject to the conditions, provided in Section 17.3.2; and revenue allocations otherwise calculated under Section 17.2 shall be adjusted as, when, and to the extent, and subject to the conditions, provided in Section 17.3.4.

17.3.1. During the Transition Period, a Participant with a Monthly Capacity Deficiency can pay a *Discounted* Deficiency Charge for so much of such Monthly Capacity Deficiency as was due to an Excused Transition Deficit. To obtain an Excused Transition Deficit for a Binding Season, the Participant must provide a Senior Official Attestation attesting that the Participant *or a relevant third party servicing load for which the Participant is the LRE* has made commercially reasonable efforts to secure Qualifying Resources in the quantity needed to satisfy the Participant's FS Capacity Requirement for the Binding Season, but is unable to obtain Qualifying Resources in the quantity required for the Binding Season because the supply of such resources on a timely basis and on commercially reasonable

terms is at that time inadequate. *If the attestation relates to a third-party servicing load for which the Participant is the LRE, the Senior Official Attestation may be signed by a Senior Official of the third party load service provider, as further detailed in the Business Practices.* Excused Transition Deficits are not resource specific, relate to a MW quantity of the Participant's FS Capacity Requirement, and are limited for each Participant as to a Binding Season during the Transition Period to a maximum permissible MW quantity equal to a percentage value times the FSPRM applicable to such Participant for all Forward Showing Submittals submitted by such Participant for such Binding Season. For purposes of such calculation, the percentage value is*: 200*% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and 100*% for each of the *2028* Summer Season and *2028-2029* Winter Season.

17.3.2 A Participant will pay a *Discounted* Deficiency Charge as to the portion of its Monthly Capacity Deficiency for which it obtained an Excused Transition Deficit. The *FS* Deficiency Charge otherwise applicable to such Participant under Section 17.2 shall be reduced by a percentage value equal to 75% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and* 50% for each of the *2028* Summer Season and *2028-2029* Winter Season. The Participant will be assessed a*n FS* Deficiency Charge calculated under Section 17.2, without reduction or adjustment, for any of its Monthly Capacity Deficiency that is in excess of the amount of such deficiency for which it obtained an Excused Transition Deficit.

17.3.3 Whether or not a Participant obtains an Excused Transition Deficit as to a Binding Season, the Participant may reduce a Monthly Capacity Deficiency otherwise calculated under Section 17.1 for a Binding Season during the Transition Period to the extent such deficiency is due to the Participant's inability to obtain assent from the supplier under a Legacy Agreement to the accreditation required for such Legacy Agreement under Part II of this Tariff and the Business Practice Manuals. To obtain such relief, the Participant must provide a Senior Official Attestation attesting that the Participant made commercially reasonable efforts to execute the required accreditation form with the supplier under the Legacy Agreement, but the supplier was unable or unwilling to counter sign the accreditation form. The reduction in Monthly Capacity Deficiency permitted by this Section 17.3.3 as to any Participant for all Forward Showing Submittals submitted by such Participant for any Binding Season during the Transition Period shall not exceed a MW quantity equal to 25% times the FSPRM applicable for such Participant for such Binding Season. To the extent a Participant reduces a Monthly Capacity Deficiency under this subsection, the percentage of the Participant's FSPRM corresponding to the reduction hereunder shall reduce the maximum permissible percentage of FSPRM reduction allowed under Section 17.3.1 for Excused Transition Deficits for the same Binding Season.

17.3.4 A Participant that, as a result of application of this Section 17.3, pays no Deficiency Charge as to a Binding Season, shall not be deemed a "Participant[ ] with no Deficiency Charges" for purposes of Section 17.2.10, and shall not receive an allocation of revenues from the payment of Deficiency Charges as to such Binding Season.

PART III OPERATIONS PROGRAM

18. Operations Program Overview

18.1 The Operations Program facilitates access to collective capacity made available through regional load and resource diversity of all Participants under the terms of this Part III.

18.2 The Operations Program evaluates forecasted system conditions across the seven-day period ("Multi-Day-Ahead Assessment") preceding the Operating Day, commencing at the outset of the assessment period with an initial Sharing Calculation and initial identification of potential Sharing Events for the Operating Day. The assessment is refined as forecasted conditions for the Operating Day are revised and established on the Preschedule Day, a Holdback Requirement for any Sharing Events is then identified. To the extent a Sharing Event continues to be identified for the Operating Day, Holdback Requirements shall be converted into Energy Deployments on the Operating Day.

18.3 The Operations Program prescribes pricing designed to incent Participants to resolve any forecast Operating Day deficiencies before the Operating Day, including through transactions outside the Operations Program, and to fully compensate Participants that provide support through the Operations Program to Participants with Operating Day deficiencies.

19. Operations Program Timeline and Supporting Information

19.1 The Operations Program includes a Multi-Day Ahead Assessment that looks ahead at the next seven Operating Days by performing an indicative Sharing Calculation from Participant forecast data for each future Operating Day up until the Preschedule Day. The Sharing Calculation for the Preschedule Day is not indicative but is binding, subject to Sections 20.2.4 and 20.3. Participants shall provide WPP with forecasts for the next seven Operating Days of expected (i) load, (ii) output of VERs, (iii) output of RORs, (iv) Contingency Reserves, and (v) forced outages, including outages on transmission facilities the Participant utilized to meet its Forward Showing Capacity Requirement, as further described in the Business Practice Manuals. WPP shall utilize the forecast data obtained in the Multi-Day-Ahead Assessment to calculate or revise the indicative Sharing Calculations for each day thereafter, up until the Preschedule Day, and will use such forecast data to revise the indicative Sharing Calculation hourly during the Operating Day. Such forecast data will also be used to calculate the binding Sharing Calculation for the Preschedule Day.

19.2 The Operations Program, during any Binding Season, shall rely on and employ (among other data) the following information from the Forward Showings for such Binding Season: (i) the P50 Peak Load Forecast for each Participant; (ii) the Monthly FSPRMs for each Participant during such Binding Season; (iii) expected performance by Qualifying Resource type and any RA Transfers; (iv) expected forced outage rates by resource type; (v) expected Contingency Reserves; and (vi) firm transmission service rights made available for purposes of regional diversity sharing under the WRAP, permitted under Part II of this Tariff, which shall be assumed to be available for all hours of each Month for which such firm transmission service rights were made available.

19.3 To facilitate WPP's conduct of the Multi-Day-Ahead Assessment, each Participant shall provide the Program Operator information relevant to the Participant's expected demand and supply conditions on each Operating Day, of the type, in the manner, and with the frequency, specified in the Business Practice Manuals.

19.4 Each Participant in any Subregion identified in the Business Practice Manuals as not containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion, shall, in addition to providing the information required by Section 19.3, identify, on or before the deadline during the Preschedule Day specified in the Business Practice Manuals, for each Hour of the Operating Day each point to which it can deliver energy, each point at which it can take receipt of energy, the quantity it can deliver or receive at each such point, and a numeric factor intended to prioritize use of transmission made available by Participants with positive Sharing Calculations and needed by Participants with negative Sharing Calculations for each such hour. A Participant with a positive Sharing Calculation for an hour must provide a total quantity for all identified points at which it can deliver that is no less than the amount of its positive Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance

with Section 20.1.2). A Participant with a negative Sharing Calculation for an hour must provide a total quantity for all identified points at which it can take receipt that is no less than the amount of its negative Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance with Section 20.1.2). Participants shall provide this same information for each Operating Day on an expected or preliminary basis on each day of the Multi-Day-Ahead Assessment following, and based on, the expected Holdback Requirement estimates provided on each such day for the Operating Day.

19.5 Any Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result may, at its sole election, offer such supply to the WRAP as Voluntary Holdback. If the offering Participant has a positive Sharing Calculation result, the offered capacity shall be in addition to that Sharing Calculation result; if the offering Participant has a negative Sharing Calculation result, the offered capacity will only be included in the allocation of Holdback Requirement so long as the offering Participant did not confirm a need for Holdback Capacity for such hour. Such offers must be submitted within the time window identified in the Business Practice Manuals, must include the information identified in Sections 19.3 and 19.4, as applicable, and must conform to the format and content identified in the Business Practice Manuals. An offer of Voluntary Holdback may become part of the Participant's Holdback Requirement when it is included in the allocation on the Preschedule Day prescribed by Section 20.2.

20. Components of the Operations Program

20.1 Sharing Calculation

20.1.1 WPP shall implement, as more fully described in the Business Practice Manuals, with respect to each Forward Showing Submittal accepted by WPP for a Participant under Part II of this Tariff, or with respect to each Subregion in which the Participant is responsible for load regardless of whether the Participant submitted a single Forward Showing Submittal encompassing its loads in both Subregions, the following Sharing Calculation to identify any hour in which any Participant is forecast to have a capacity deficit (known as a "Sharing Event"). This calculation takes into account changes in a Participant's resource availability, resource performance, forecast load, and Contingency Reserve relative to the Forward Showing, plus an Uncertainty Factor. The Sharing Calculation is equal to:

[(P50) * (1 + FSPRM) + Contingency Reserve Adjustment] – [Load Forecast – Demand Response Capacity Resources + Contingency Reserve Obligation + Uncertainty Factor] + [ΔForced Outages + ΔRoR Performance + ΔVER Performance]

Where:

P50 refers to the Participant's Monthly P50 Peak Load for that Binding Season's Month;

FSPRM, as described in Section 16.1.2, is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages and is expressed as a percentage of the applicable Participant P50 Peak Load Forecast for that Binding Season's month;

Contingency Reserve Adjustment accounts for changes in Contingency Reserve expectations (relative to the 6% Contingency Reserve assumed in the FSPRM) resulting from energy contract purchases and contract sales as set forth in the Business Practice Manuals;

Load Forecast refers to the forecast of expected load for the subject hour for the loads for which the Participant is the Load Responsible Entity and that have not been excluded from WRAP participation;

Demand Response Capacity Resource as described in Section 16.2.5.4.

Contingency Reserve Obligation refers to the amount of Contingency Reserve the Participant is carrying during the operating hour equal to (i) 3% of Load Forecast for which the Participant is the WRAP LRE and maintains

its Contingency Reserve, (ii) plus 3% of WRAP load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement, (iii) plus 3% of generation used to meet any load for which the Participant is the LRE and maintains the Contingency Reserve, (iv) plus 3% of generation utilized to meet WRAP Load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement;

Uncertainty Factor refers to a factor determined by WPP, as more fully set forth in the Business Practice Manuals, to account for the potential variance between forecasts of load, solar resources, wind resources, and run-of-river resources, and the Operating Day conditions of such load and resources;

Δ Forced Outages refers, for the subject hour, to the sum of:

(i) any change in forced outages of any of the thermal resources included in the Participant's Portfolio QCC, relative to the forced outages assumed in the Forward Showing Submittal by application of the Forced Outage Factor; plus

(ii) any change in forced outages of any of the Storage Hydro Qualifying Resources relative to the forced outages assumed in the calculation of the Participant's Resource QCC as more fully described in the Business Practice Manuals; plus

(iii) any reduction in output capability of any of the Energy Storage Resources due to equipment failure or protection
   a. In the first four (4) hours the Forced Outages MWs that can be claimed are equal to [(charge MW x duration)/4]
   b. For all hours beyond four (4) hours, the Forced Outages MW amount that can be claimed for an Energy Storage Resource shall not be greater than the monthly QCC; plus

(iv) any impacts of transmission conditions on previously acquired firm transmission service rights that result in capacity reductions up to the level of the Resource QCC of the associated Qualifying Resource;

ΔRoR Performance refers to any change, for the subject hour, in expected performance of any of the run-of-river resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources; and

ΔVER Performance refers to any change, for the subject hour, in expected performance of the VER Resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources;

20.1.2 In addition to the foregoing, the Sharing Calculation for a Participant that is a purchaser of an RA Transfer shall be performed in two passes, with and without such purchase. If the result of assuming in the first pass that the Participant had not purchased the RA Transfer is that the Participant has a

negative Sharing Calculation, then the Participant that sold the RA Transfer must agree, for the time period addressed by the Sharing Calculation, to an energy delivery to the Participant that purchased the RA Transfer, in an amount equal to the lesser of: (i) the MW quantity needed to result in a net zero Sharing Calculation for the Participant that purchased the RA Transfer; and (ii) the MW amount of the RA Transfer. If the result of recognizing the Participant's purchase of the RA Transfer in the second pass is that the Participant has a positive Sharing Calculation, then the Participant that sold the RA Transfer must assume a share of the purchasing Participant's resulting obligation to the Operations Program in an amount equal to the MW quantity of the RA Transfer, minus the MW quantity of the delivery made by the seller of the RA Transfer to the purchaser of the RA Transfer as a result of the first pass.

20.1.3 The Sharing Calculation of any Participant that was found to have a Monthly Capacity Deficiency under Sections 16.1 and 16.2, for which such Participant paid a Deficiency Charge, including any Deficiency Charge reduced by application of Section 17.3 during the Transition Period, shall be reduced by the MW quantity of such Monthly Deficiency.

20.2 Holdback Requirement

To the extent that: (i) WPP's application of the Sharing Calculation identifies on the Preschedule Day a Sharing Event for any hour(s) of the Operating Day; and (ii) the Participant(s) found to be deficient for such hour(s) by the Sharing Calculation confirms to WPP on the Preschedule Day, in accordance with notification and confirmation procedures set forth in the Business Practice Manuals, such Participant's need for capacity for such hour(s), then WPP shall determine the Participants having a Holdback Requirement for such hour(s) and the quantity of the Holdback Requirement for each such Participant in accordance with this Section 20.2. The Operations Program will prioritize offers of Voluntary Holdback in the allocation and assignment of Holdback Requirements. Holdback Requirements shall be expressed as whole MWs for each hour for which they are estimated or established and shall not be specific to any Qualifying Resource.

20.2.1 Subregion with Central Hub

For any hour, as to any Subregion identified in the Business Practice Manuals as containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion ("Central Hub"), the aggregate of the holdback needed to meet the requirements of all Participants with negative Sharing calculation results that have confirmed their need for holdback will be allocated and assigned first among offers of Voluntary Holdback, and second, to the extent such needs remain unmet, among Participants with positive Sharing Calculation results.

20.2.1.1 Allocation of Voluntary Holdback: Voluntary Holdback will be allocated in one of three alternative ways, based on comparing the aggregate confirmed need for holdback among Participants with negative Sharing Calculation results against the aggregate of all offers for Voluntary Holdback.

20.2.1.1.1 If the total MW quantity of all Voluntary Holdback offered is equal to the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned its offered Voluntary Holdback as its Holdback Requirement.

20.2.1.1.2 If the total MW quantity of all Voluntary Holdback offered is more than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned as its Holdback Requirement a percentage of the total confirmed need for holdback based on the ratio of the Participant's MWs of offered Voluntary Holdback to the sum of all Participants' MWs of offered Voluntary Holdback.

20.2.1.1.3 If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant's Holdback Requirement is determined as set forth in section 20.2.1.2.

20.2.1.2 Allocation of Remaining Holdback Requirement: Sharing Calculation Results

If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then the maximum Voluntary Holdback offered is used as the first term in the Holdback Requirement. The remaining term of the Holdback Requirement is met by application of the Sharing Calculation, and the results of the two terms are summed for each Participant. The remaining need for holdback that is not met by Voluntary Holdback is allocated among all Participants with positive Sharing Calculation results pro rata based on the ratio for each Participant of the Participant's positive Sharing Calculation result to the sum of the positive Sharing Calculation results. The

sum of these two values for each applicable Participant is the Holdback Requirement for that Participant.

20.2.2 Subregion without Central Hub

For any hour, any Subregion not containing a Central Hub, the Program Operator shall conduct an optimization-based allocation to pair surplus and deficient Participants. The allocation methodology will utilize the points at which surplus Participants can deliver their Holdback Requirement, the points at which deficient Participants can take receipt of their allocation of the total Holdback Capacity, and the transfer capability that exists to the points at which surplus Participants can deliver and the points at which deficient Participants can take receipt.

The optimization will generally attempt to prioritize (i) Voluntary Holdback; (ii) Holdback Capacity matched pursuant to the information provided per Section 19.4 on a nearest neighbor and cluster basis, allocated pro rata among Participants within such cluster; (iii) Holdback Capacity matched pursuant to the information provided and allocated among Participants within the same Subregion to the extent not matched and allocated under category (ii); and finally (iv) Holdback Capacity from Participants in another Subregion, paired with any transmission service per Section 14.3.2.

20.2.3 Absent a Holdback Requirement Transfer as described below, a Participant's Holdback Requirement for any hour of an Operating Day shall not exceed the level first set by WPP on the Preschedule Day for that Participant for that hour.

20.2.4 Any Participant may agree with any other Participant for the first Participant to transfer to the second Participant some or all of the Holdback Requirement established for the first Participant for any hour on any Operating Day. Any such Holdback Requirement Transfer shall be a bilateral arrangement settled outside the Operations Program, provided, however, that both Participants must timely notify WPP, by the time and in the manner described in the Business Practice Manuals, of such Holdback Requirement Transfer. Any necessary transmission arrangements and any transaction settlements shall be the sole responsibility of the Participants that are the parties to such bilateral arrangement.

20.2.4.1 No Holdback Requirement transfer for any hour shall be permitted if notice of such bilateral transaction is not fully reported to WPP, in the form required by the Business Practice Manuals, by 120 minutes before the start of such hour.

20.3 Release of Surplus Capacity

20.3.1 As detailed in the Business Practice Manuals, WPP will review the indicative Sharing Calculation results from the Multi-Day Ahead Assessment and to the extent the WPP determines any indicative Sharing Calculations can be reduced, it may release all or a portion of Participants' future Holdback Requirements. WPP may permit a release of future Holdback Requirements to the extent WPP has not applied a Safety Margin for such hour and (i) WPP's continued Sharing Calculations determine that no Participant has a negative indicative Sharing Calculation result for such hour; and (ii) WPP determines there is a low probability of a Sharing Event for the hour; or (iii) WPP grants a Participant's request for extenuating circumstances of all or any portion of that Participant's future Holdback Requirement for the hour.

20.3.2 Upon release of all or any portion of a future Holdback Requirement, the quantity of future Holdback Requirement so released shall no longer be subject to an Energy Deployment requirement under the Operations Program for the subject hour.

20.4 Energy Deployment

20.4.1 Participants shall provide energy during an hour, in support of any Participants with a negative Sharing Calculation result and a confirmed need for energy under the Operations Program for such hour, in accordance with WPP's calculation of the Energy Deployment for such hour. The total Energy Deployment required of all Participants that are subject to Energy Deployment shall equal the sum, in MWh for that hour, of the energy confirmed as being needed in that hour by Participants in such Subregion with negative Sharing Calculation results in such hour, to the extent that can be supported by the Program. The Energy Deployment assigned to each Participant shall not exceed that Participant's Holdback Requirement calculated on the Preschedule Day, adjusted for any applicable transfer of Holdback Requirement as allocated and assigned for the Preschedule Day, and, as further adjusted to reflect the election, made after the Preschedule Day, of any Participant with a negative Sharing Calculation result on the Preschedule Day to decline all or any part of the Holdback Capacity to which it would have been entitled based on the Holdback Requirements determined on the Preschedule Day.

20.4.1.1 In Subregions with a Central Hub, Energy Deployments required hereunder shall be delivered to the Central Hub in such Subregion, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.1.2 In Subregions without a Central Hub, Energy Deployments required hereunder shall be delivered to the receipt point and delivery point as indicated by the optimization allocation, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.2 The Energy Deployment a Participant may receive for any hour shall be no greater than the negative Sharing Calculation result calculated for such Participant for such hour. Such Participant shall confirm, by no later than 85 minutes before the start of such hour, the quantity of Energy Deployment for which it requires delivery for such hour, through the procedures outlined in the Business Practice Manuals. Any Participant that does not confirm required Energy Deployment deliveries for such hour by such deadline will be deemed to waive all deliveries of Energy Deployment under the Operations Program for such hour.

20.4.3 The Energy Deployment a Participant can be required to supply for an hour shall not exceed the final Holdback Requirement calculated for such Participant on Preschedule Day, including any duly reported exchange of Holdback Requirement, as of 85 minutes before the start of such hour.

20.4.4 WPP shall advise each Participant with a required Energy Deployment for an hour of the required MWh quantity and delivery point of such Energy Deployment by no later than 80 minutes before the start of such hour.

20.5 Safety Margin

20.5.1 WPP may establish on the Preschedule Day a Safety Margin for the WRAP Region or any identified Subregion thereof for any hour of an Operating Day when warranted by such circumstances as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, or other similar regional or subregional conditions, as more fully set forth in the Business Practice Manuals.

20.5.2 Any Safety Margin so determined for an hour shall be allocated pro rata among Participants with a positive Sharing Calculation result, based on their relative shares of the sum of all positive Sharing Calculation results for such hour, provided, however, that the Safety Margin allocated to a Participant may not result in a Holdback Requirement for such Participant greater than such Participant's Sharing Calculation result. A Participant allocated holdback for a Safety Margin hereunder does not receive compensation under this Tariff for such allocation of holdback.

20.5.3 WPP shall notify all Participants of application of a Safety Margin for any hour, including in such notice the total timeframe, the MW amount, and the rationale for such Safety Margin.

20.6 Operations Program Transmission Service Requirements

Participant shall have in place, prior to the Operating Day, transmission service satisfying NERC Priority 6 or 7 for each hour of such Operating Day for which a Sharing Event has been established, in a quantity sufficient for deliveries from the Qualifying Resources relied upon in such Participant's Forward Showing Submittal to demonstrate satisfaction of such Participant's FS Capacity Requirement (or from replacement Qualifying Resources) to serve such Participant's loads during such hours. In the event a Participant has an Energy Delivery Failure, the review associated with the possible assessment of a Delivery Failure Charge on such Participant shall, as further described in the Business Practice Manuals, include whether a failure to secure sufficient NERC Priority 6 or Priority 7 firm transmission service rights caused or contributed to such Energy Delivery Failure. For such purpose, the Participant will have been expected to have complied with the transmission service requirement stated in this subsection.

20.7 Failure to Deliver Energy Deployments

20.7.1 A Participant assigned a required Energy Deployment pursuant to Section 20.4.4 of this Tariff for any hour that fails to deliver the specified energy during such hour, and that does not obtain a waiver of its Energy Deployment obligation, shall be assessed a Delivery Failure Charge.

20.7.2 A Participant shall be deemed to have an Energy Delivery Failure if Participant fails to deliver the Energy Deployment quantity established under Section 20.4.1, absent grant of a waiver pursuant to Section 20.7.3 of this Tariff.

20.7.3 A Participant anticipating an Energy Delivery Failure should provide WPP notice of such expected Energy Delivery Failure as soon as practicable after becoming aware of the anticipated failure. Whether anticipated or not, a Participant may request a waiver of an Energy Deployment obligation after an Energy Delivery Failure has occurred. The WPP shall review all such waiver requests and shall determine whether the Participant's justification for the Energy Delivery Failure is valid and warrants waiver of its Energy Deployment obligation. The WPP also shall consider whether the Participant knew in advance, or reasonably should have known in advance, of an Energy Delivery Failure, and what efforts the Participant took to notify the WPP in advance of such Energy Delivery Failure. The procedures for addressing such waiver requests, including a non-exclusive list of valid justifications for an Energy Delivery Failure shall be set forth in the Business Practice Manuals. A Participant denied a waiver request hereunder may appeal such denial to the Board of Directors in accordance

with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested waiver shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall report on the disposition of each waiver request received.

20.7.4 The Delivery Failure Charge for each hour shall be the Charge Rate applicable for such hour times the MWhs of energy that were required to be, but were not, delivered pursuant to an Energy Deployment during such hour. The Charge Rate shall be the higher of the Day-Ahead price or Real-Time price provided by the Day-Ahead Applicable Price Index and Real-Time Applicable Price Index as specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery, respectively, for the hour, times a Delivery Failure Factor, as follows:

20.7.4.1 If the deficit is fully covered by other Participants through the Operations Program, in each instance of failure, the Delivery Failure Factor shall be five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; ten for the second non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and twenty for the third and subsequent non-waived Energy Delivery Failures in a Cumulative Delivery Failure Period. For purposes of applying the Delivery Failure Factors under this Section 20.7.4 or the review referenced in Section 20.7.5, multiple Energy Delivery Failures occurring in one day shall be treated as a single instance of failure.

20.7.4.2 If the deficit is not fully covered by other Participants through the Operations Program, the Delivery Failure Factor is twenty-five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and fifty for the second and subsequent non-waived Energy Delivery Failures (regardless of whether the prior instance(s) of delivery failure were fully covered by other Participants) in a Cumulative Delivery Failure Period.

20.7.4.3 Revenues from Delivery Failure Charges assessed in cases where the deficit was fully satisfied by other Participants will be used to reduce WPP costs that are recovered under Schedule 1, WRAP Administration Charge. Revenues from Delivery Failure Charges assessed in cases where the deficit was not fully met by other Participants will be collected by the WPP and provided to the Participant that had an unserved deficit.

20.7.4.4 Notwithstanding anything to the contrary in this Section 20.7.4, the Delivery Failure Charges assessed on a Participant, regardless of application of the Delivery Failure Factor, shall not

exceed, over the course of a Summer Season and the immediately succeeding Winter Season, the dollar amount that, as more fully detailed in the Business Practice Manuals, would have been assessed cumulatively under Section 17 as Deficiency Charges if the Participant had one or more Forward Showing Capacity Deficiencies over the course of such Summer Season and Winter Season in the same MW amounts as the highest MW amount of Delivery Failure experienced by such Participant in each Month of such Summer Season and Winter Season. The maximum dollar amount described herein shall be calculated on an ongoing basis during such Summer Season and Winter Season, and increased or reduced accordingly, without awaiting the end of the combined period of such Summer Season and Winter Season.

20.7.5 In addition to assessment of the Delivery Failure Charge, a third or subsequent instance of non-waived delivery failure, when all such delivery failures are fully covered by other Participants, or a second or subsequent instance of non-waived delivery failure when such instance is not fully covered by other Participants, will subject the Participant to review for expulsion from the WRAP.

20.8 Voluntary Response to Increased Deficiencies Identified After Preschedule Day

20.8.1 A Participant that identifies an unmet need for energy for any hour of an Operating Day that is outside of assistance provided or to be provided by Holdback Requirements or Energy Deployments established hereunder may, in accordance with procedures specified in the Business Practice Manuals, notify WPP of the need for such assistance. WPP will establish a portal or other procedure, as specified in the Business Practice Manuals, to facilitate provision of assistance, on a voluntary, bilateral basis, by other Participants to the Participant that identified the unmet need. Compensation, terms, and conditions of any resulting bilateral transactions will be determined by the affected parties outside of this Tariff. While Participant response to any such notification is voluntary, Participants are encouraged to provide assistance to other Participants in the circumstances described in this subsection, in consideration of the mutual support each Participant has agreed to provide to each other Participant by its agreement to participate in the WRAP, including this Operations Program.

21. Operations Program Settlements

21.1 Nature of Operation Program Settlements

21.1.1 Operations Program settlements are bilateral transactions; they are not purchases from or sales to a central market.

21.1.2 Operations Program transactions use existing transaction systems and processes.

21.1.3 The WPP will calculate and post settlement quantities and prices based on the Energy Deployment and Holdback Requirement, in accordance with procedures specified in the Business Practice Manuals for provision of transaction information by and among Participants and WPP, but WPP has no role in the transaction itself. WPP is not a settlement entity.

21.1.4 Settlement Prices calculated under Section 21.2 shall recognize pricing differences among Subregions. Where the seller and buyer are located in the same Subregion, the Applicable Price Index shall be the price index specified for that Subregion in the Business Practice Manuals. Where the seller and buyer are located in different Subregions, the following components of the settlement price calculation in Section 21.2 will be calculated using the Applicable Price Index for the Subregion that provides the higher index price: (i) Possible Block Sale Revenue; (ii) Total Settlement Price; (iii) Energy Declined Settlement Price; and (iv) Realtime Value of Unheld Energy. If a third participant is involved by providing transmission service rights between Subregions, the Participant that provided holdback or Energy Deployment shall receive the settlement price of the Subregion from which the holdback or Energy Deployment was sourced, and the Participant that provided Subregion to Subregion transmission service rights pursuant to Section 19.4 shall receive the difference between each Subregion's Total Settlement Price, or zero, whichever is greater.

21.2 Settlement Price Calculation. Settlement prices shall be calculated in accordance with the following, as more fully set forth in the Business Practice Manuals.

21.2.1 A Participant assigned a Holdback Requirement on a Preschedule Day for any hour of an Operating Day shall be paid the Holdback Settlement Price times the MW quantity of the Holdback Requirement. A Participant that provides energy to another Participant pursuant to an Energy Deployment shall be paid the Energy Declined Settlement Price, defined in Section 21.2.4, times the MWhs of energy provided to such other Participant, and its total payments shall be reduced by the Energy Declined Settlement Price times the MWhs of energy that would have been provided under a Holdback Requirement but were declined by the other Participant. A Participant

assigned a Holdback Requirement also shall be paid, when applicable, a Make Whole Adjustment, as provided below in Section 21.2.5.

21.2.2 A Participant that had a negative Sharing Calculation result for any hour of an Operating Day, which was incorporated in the calculation of Holdback Requirements of any Participants for such hour, determined as of the Preschedule Day, shall pay the Holdback Settlement Price times the MW quantity of such negative Sharing Calculation result. In addition, any Participant that had a negative Sharing Calculation result that was incorporated in the calculation of a Holdback Requirement shall contribute to the payment of the Make Whole Adjustment based on its negative Sharing Calculation. A Participant that declines energy that would have been provided under a Holdback Requirement shall be credited the Energy Declined Settlement Price times the MWhs of energy declined by such Participant.

21.2.3 The Holdback Settlement Price shall equal the Total Settlement Price minus the Energy Declined Settlement Price.

21.2.4 The Energy Declined Settlement Price shall equal the Applicable Real-Time Index Price for the hour.

21.2.5 The Make Whole Adjustment is applied in the event that the settlement revenue and the estimated value of the non-dispatched energy is less than the estimated revenues the selling entity would have received had such entity not been subject to a Holdback Requirement and had sold a day-ahead block of energy with a MW value equal to the maximum amount of Holdback Requirement for the hours in the block. The Make Whole Adjustment has a minimum value of zero and is determined as follows:

Make Whole Adjustment (when applicable) =
Maximum of (Possible Block Sale Revenue
– Final Settlement Revenue
– Realtime Value of Declined Energy
– Realtime Value of Unheld Energy, 0)

Where:

Realtime Value of Declined Energy = Energy Declined × Energy Declined Settlement price

provided that Declined Energy is only applicable to those hours where there was a positive Holdback Requirement.

Realtime Value of Unheld Energy = (Maximum Holdback MW in Block – Holdback MW Requested) × Applicable Index Price

21.2.6 The Total Settlement Price used in the above calculations shall be determined in accordance with the following formula:

Total Settlement Price = Maximum of (Minimum of (Hourly Shaping Factor × Day Ahead Applicable Index Price × 110%, 2000 $/MWh), 0)

where:

Hourly Shaping Factor is based on the most recent High-Priced Day for the relevant season, defined as a day in which at least one hour has a system marginal energy cost ("SMEC") greater than $200/MWh, and shall be calculated as follows:

1 + {[CAISO Hourly Day Ahead SMEC - CAISO Average Day Ahead SMEC (on- or off-peak hours)] / [CAISO Average Day Ahead SMEC (on- or off-peak hours)]}

Day-Ahead Applicable Index Price is the day-ahead heavy load/light load ICE Index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery. If transmission via Section 14.3.2 was used to facilitate holdback, the Applicable Index Price shall be the higher of the two subregional day-ahead index prices for that portion of the holdback.

Real-Time Applicable Index Price is the real-time index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery.

SCHEDULE 1

WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

The Western Power Pool's Costs of administering and operating the Western Resource Adequacy Program including, without limitation, all costs incurred or obligated by WPP as Program Administrator, all costs paid or payable by WPP to the Program Operator or other service providers, all costs of the Board of Directors in directing, supervising, or overseeing the WRAP, and the costs of maintaining a reasonable reserve as provided in Section 1 of this Schedule 1, shall be recovered from Participants pursuant to the charges set forth in this Schedule 1.

Section 1. WRAP Costs

1. As used herein, Costs shall mean WPP's costs, expenses, disbursements and other amounts incurred (whether paid or accrued) or obligated of administering and operating the WRAP as described above, including, without limitation, operating expenses, general and administrative expenses, costs of outside services, taxes, fees, capital costs, depreciation expense, interest expense, working capital expense, any costs of funds or other financing costs, and the costs of a reasonable reserve as provided herein.
2. The Costs included in a WRAP Administration Charge assessed for a Month shall be the Costs determined as being incurred for that Month, including, without limitation, for each Month, one-twelfth of any annual charge(s).

3. The Costs included in the WRAP Administration Charge for a reasonable reserve shall be those designed to establish over the first twelve months that this WRAP Administration charge is in effect an amount equal to 6% of the expected Costs, exclusive of such reserve, for one year; and to maintain such reserve thereafter at an amount equal to 6% of the expected Costs, exclusive of such reserve for the then-current year. WPP shall record on its income statement deferred regulatory expense, and WPP's balance sheet will reflect as a cumulative deferred regulatory liability, revenues collected under this Schedule 1 that are in excess of the Costs exclusive of such reserve and taking account of and including any accrued tax expense effects of this regulatory liability. The deferred regulatory liability will be reduced when after-tax WPP revenues collected under this Schedule 1 during any Month are less than the Costs exclusive of such reserve. Within thirty days after the end of each Year, to the extent WPP determines that the deferred regulatory liability exceeds 6% of WPP's revenues that were collected under this Schedule 1 during such Year, such excess amounts in the deferred regulatory liability shall be refunded evenly over the applicable billing determinant volumes in the remainder of the subsequent Year through credits to charges to then-current customers under this Schedule 1.

Section 2. WRAP Administration Charge

Each Participant shall be assessed each Month a WRAP Administration Charge equal to the sum of the Base Charge and the Load Charge,

where:

The Base Charge for each Participant equals the Base Costs divided by the number of Participants being assessed the Base Charge for the Month for which the WRAP Administration Charge is being calculated;

The Load Charge for each Participant equals the Load Charge Rate of the Load Services Costs divided by the sum of the Median Monthly P50 Peak Loads of the Participants being assessed the Load Charge for the Month for which the WRAP Administration Charge is being calculated, times that Participant's Median Monthly P50 Peak Load;

And where:

Base Costs means the Costs for the Month of the Base Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Base Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown below in Section 4: WRAP Cost Assignment Matrix;

Load Services Costs means the Costs for the Month of the Load Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Load Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown in the WRAP Cost Assignment Matrix; and

Median Monthly P50 Peak Loads means, for each Participant, the median of the Monthly P50 Peak Loads used in the FS Capacity Requirement of such Participant for two Binding Seasons corresponding to the two FS Submittal most recently validated by WPP.

If before or during a Binding Season, a Participant has need to update their Monthly P50 Peak Load for allowable reasons, those updated Monthly P50 Peak Loads will be replaced and the Median Monthly P50 Peak Load value recalculated upon validation of the change in participating load.

A Participant joining the Program will supply data such that WPP can validate Monthly P50 Peak Loads for the first two Binding Seasons for which the Participant will submit an FS Submittal for use in calculating Load Services Costs until these FS Submittals are submitted and reviewed in the normal timeframe.

Section 3. Maximum Charge Rates

3.1 Notwithstanding anything to the contrary in this Schedule 1, the sum of the Base Charges for all Months in a Year shall not exceed the Annual Maximum Base Charge of $59,000/Year, and the sum of the Load Charge Rates for all Months in a Year shall not exceed the Annual Maximum Load Charge Rate of $199/MW. WPP shall, to the extent reasonably practicable, provide two-months' notice prior to WPP's filing at FERC of an application to change the Maximum Base Charge or the Maximum Load Charge Rate, provided that nothing herein shall limit the Board of Director's authority and discretion to seek at FERC a change in the maximum rates in the time and manner the Board determines in the best interests of the Western Resource Adequacy Program. For purposes of clarity, these specified maximum rates on the Base Charge and the Load Charge do not limit the level of the Cash Working Capital Support Charge established under Section 5 of this Schedule 1, nor do they limit the amount of the default Allocation assessment provided under Part I of this Tariff.

3.2 To facilitate Participant planning, the WPP shall prepare, and provide to the RAPC, good faith, non-binding estimates of: (i) reasonably anticipated WRAP budgets for three Years beyond the most recently approved WRAP budget, including sensitivity analyses for reasonably identified major contingencies; (ii) reasonably anticipated numbers of Participants and MWs of Winter and Summer P50 Loads for each such Year; and (iii) reasonably anticipated highest monthly Base Charges and Load Charge Rates for each such Year. All assumptions and estimates in such forecasts and analyses shall be in WPP's sole discretion, which may be informed by RAPC discussion of such topics.

Section 4. WRAP Cost Assignment Matrix

	BASE COSTS	LOAD COSTS	DUAL BENEFIT
PROGRAM ADMINISTRATION (NON-PARTICIPANT)		100%	
PROGRAM ADMINISTRATION (PARTICIPANT ENGAGEMENT, RAPC FACILITATION)	100%		
WRAP PORTION OF WPP BOD COSTS			50%/50%
PROGRAM OPERATIONS STAFFING AND OVERHEAD		100%	
PROGRAM OPERATIONS TECHNOLOGY		100%	

LEGAL SERVICES	100%
INDEPENDENT EVALUATOR	100%

Section 5. Cash Working Capital Support Charge

5.1 In addition to the WRAP Administration Charge, each Participant shall be assessed a Cash Working Capital Support Charge, to support WPP's maintenance of sufficient funds on hand to make payments required for the operation and administration of the WRAP on a timely basis. Cash Working Capital Support Charges shall be designed to maintain a Cash Working Capital Fund that, at its maximum level over a twelve-month cycle, equals approximately nine-twelfths of the expected annual payment due from the WPP to the Program Operator for its Program Operator services.

5.2 A Participant shall pay a Cash Working Capital Support Charge no later than thirty days after that Participant executes a WRAPA. The Cash Working Capital Support Charge due following WRAPA execution equals the Cash Working Capital Support Charge Rate, calculated as the Cash Working Capital Fund at its required maximum twelve-month cycle level divided by the sum of the Median Monthly P50 Peak Loads of all Participants, times that Participant's Median Monthly P50 Peak Load.

5.3 To the extent the Cash Working Capital Fund is adequately funded at the time a new Participant executes a WRAPA, the revenue from such Participant's payment of the Cash Working Capital Support Charge shall be distributed to all Participants that previously have paid a Cash Working Capital Support Charge, pro rata based on the Median Monthly P50 Peak Loads of all Participants that have previously paid such charge.

5.4 To the extent, and at such time, WPP determines that an incremental addition to the Cash Working Capital Fund is needed due to such causes as, for example, an expected increase in the annual payment to the Program Operator, each Participant shall be assessed an Incremental Cash Working Capital Support Charge equal to the desired incremental addition, divided by the sum of the Median Monthly P50

Peak Loads of all Participants being assessed the Incremental Cash Working Capital Support Charge for the Month for which the Incremental Cash Working Capital Support Charge is being calculated, times that Participant's Median Monthly P50 Peak Load.

ATTACHMENT A

Western Resource Adequacy Program Agreement

This Western Resource Adequacy Program Agreement ("Agreement") dated as of _____ ("Effective Date") is entered into by and between Western Power Pool Corporation ("WPP") and _____ ("Participant"). WPP and Participant are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

In consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. The Parties agree that this agreement shall be governed by the rates, terms, and conditions of the Western Resource Adequacy Program Tariff ("Tariff") and all such rates, terms, and conditions contained therein are expressly incorporated by reference herein. All capitalized terms that are not otherwise defined herein shall have the meanings ascribed by the Tariff.

2. Participant wishes to participate in the Western Resource Adequacy Program ("WRAP") administered by WPP under the Tariff.

3. Participant certifies that it satisfies all of the following qualifications:

    3.1 Participant is a Load Responsible Entity as that term is defined in the Tariff.

    3.2 Participant commits to complying with all applicable terms and conditions of WRAP participation as set forth in the Tariff and Business Practice Manuals adopted thereunder, including all Forward Showing Program and Operations Program requirements.

4. Participant will register all resources and supply contracts and shall disclose any other obligations associated with those resources and supply contracts.

5. Participant represents and warrants that it is authorized by all relevant laws and regulations governing its business to enter into this Agreement and assume all rights and obligations thereunder.

6. It is understood that, in accordance with the Tariff, WPP, as authorized by its independent Board of Directors, may amend the terms and conditions of this Agreement or the Tariff by notifying the Participant in writing and making the appropriate filing with FERC, subject to any limitations on WPP's authority to amend the Tariff as set forth therein.

7. Participant agrees to pay its share of all costs associated with the WRAP, as calculated pursuant to Schedule 1 of the Tariff. The manner and timing of such payment shall be as specified in Schedule 1 of the Tariff.

8. WPP agrees to provide all services as set forth in the Tariff.

9. Term and termination. This Agreement shall commence upon the Effective Date and shall continue in effect until terminated either by WPP by vote of its Board of Directors or by Participant's withdrawal as set forth herein. WPP and Participant agree that participation in the WRAP is voluntary, subject to the terms and conditions of this Agreement and the Tariff. The date upon which a Participant's withdrawal is effective and its participation in the program terminates is referred to as the "Withdrawal Date."

9.1 Normal Withdrawal: In general, Participant may withdraw from this Agreement by providing written notice to WPP no less than twenty-four months prior to commencement of the next binding Forward Showing Program period. Once notice has been properly given, Participant remains in a "Withdrawal Period" until the Withdrawal Date.

9.1.1 During Participant's Withdrawal Period, Participant remains subject to all requirements and obligations imposed by the Tariff and this Agreement, including but not limited to all obligations imposed in the Forward Showing Program and Operations Program and obligation to pay Participant's share of all costs associated with the WRAP.

9.1.2 All financial obligations incurred prior to and during the Withdrawal Period are preserved until satisfied.

9.1.3 During the Withdrawal Period, Participant is not eligible to vote on any actions affecting the WRAP that extend beyond the Withdrawal Period.

9.2 Expedited Withdrawal: Participant may withdraw from this agreement with less than the required twenty-four month notice as set forth below. Participant shall negotiate with WPP regarding the timing of the Expedited Withdrawal.

9.2.1 Extenuating Circumstances: The following such events and circumstances shall constitute "extenuating circumstances" justifying a withdrawal on less than twenty-four months. Participant invoking an extenuating circumstance shall negotiate with WPP regarding potential ways to minimize the impact of the expedited withdrawal on all other Participants and WPP. Such extenuating circumstances and any mitigation plan to minimize the impact of the expedited withdrawal must be reviewed and approved by the Board of Directors prior to termination of Participant's WRAP obligations. Regardless of the extenuating circumstance, all financial obligations incurred prior to the Withdrawal Date remain in effect until satisfied.

9.2.1.1 A governmental authority takes an action that substantially impairs Participant's ability to continue to

participate in the WRAP to the same extent as previously; provided, however, that Participant shall be obligated to negotiate with WPP regarding potential ways to address the impact of the regulatory action without requiring a full withdrawal of Participant from the WRAP if possible.

9.2.1.2 Continued participation in the WRAP conflicts with applicable governing statutes or other applicable legal authorities or orders.

9.2.1.3 Participant voted against a RAPC determination and disagreed with a Board of Directors decision to release composite or aggregated data under Section 10.2.1 of the Tariff, provided that such right to expedited withdrawal is exercised promptly after the first time that the Board of Directors determines that the form and format of composite or aggregated data sufficiently protects against the release of confidential or commercially sensitive Participant data. Failure to exercise this right promptly upon the first occurrence of the Board of Directors voting on a specific form and format of composite or aggregated data shall constitute a waiver of the right to expedited withdrawal for any future disclosures of composite or aggregated data in the same or substantially similar form and format.

9.2.1.4 FERC or a court of competent jurisdiction requires the public disclosure of a Participant's confidential or commercially sensitive information, as further described in Section 10.5 of the Tariff; provided however that such right to expedited withdrawal shall be exercised promptly upon the exhaustion of all legal or administrative remedies aimed at preventing the release.

9.2.2 Exit Fee: If the impact of Participant's withdrawal on WRAP operations can calculated with a high degree of confidence and mitigated by the payment of an "exit fee" to be calculated by WPP, an expedited withdrawal will be permitted. Such exit fee shall include (but not be limited to): (i) any unpaid WRAP fees or charges; (ii) Participant's share of all WRAP administrative costs incurred up to the next Forward Showing Program period; (iii) any costs, expenses, or liabilities incurred by WPP and/or the Program Operator directly resulting from Participant's withdrawal; and (iv) any costs necessary to hold other participants harmless from the voluntary expedited withdrawal. The exit fee may be waived to the extent that it would violate any federal, state, or local statute, regulation, or ordnance or exceed the statutory authority of a federal

agency. The exit fee shall be paid in full prior to the Withdrawal Date.

9.2.3 Amendments to Section 3.4 of the Tariff: In the event that amendments to Section 3.4 of the Tariff are approved by the RAPC and Board of Directors, a Participant that voted against such a change may withdraw with less than the required twenty-four month notice, provided that the Participant satisfy all obligations in the Forward Showing Program and Operations Program and satisfy all other financial obligations incurred prior to the date that the amendments to Section 3.4 of the Tariff are made effective by FERC.

9.2.4 Expulsion: The Board of Directors, in its sole discretion, may terminate Participant's participation in the WRAP and may terminate this Agreement with Participant for cause, including but not limited to material violation of any WPP rules or governing documents or nonpayment of obligations. Prior to exercising such right to terminate, the Board of Directors shall provide notice to Participant of the reasons for such contemplated termination and a reasonable opportunity to cure any deficiencies. Such Board of Directors termination shall be after an affirmative vote consistent with the Board of Directors standard voting procedures. Such termination shall not relieve the Participant of any financial obligations incurred prior to the termination date, and WPP may take all legal actions available to recover any financial obligations from Participant.

10. No Waiver of Non-FERC-Jurisdictional Status. If Participant is not subject to the jurisdiction of FERC as a public utility under the Federal Power Act, Participant shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over Participant that does not otherwise exist. Participant acknowledges that FERC has jurisdiction over the WRAP, including Participant's activities in the WRAP.

[SIGNATURE BLOCKS]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-148:
WRAP Notice

WESTERN RESOURCE ADEQUACY PROGRAM

WPP Notice to WRAP Resource Adequacy Participants Committee

Oct. 31, 2025, 9:42 a.m. by Rebecca Sexton | Last modified Oct. 31, 2025, 12:54 p.m.

On Friday, October 31, WPP Chief Strategy Officer Rebecca Sexton sent this notice to members of the WRAP Resource Adequacy Participants Committee, regarding participants committed to WRAP binding operations in Winter 2027/2028:

Today is the deadline set in the tariff for Western Resource Adequacy Program (WRAP) participants to notify us if they plan to exit the program before binding operations start in Winter 2027/2028.

As of the deadline there are 16 current participants that will remain in the program for binding operations, including five in addition to the 11 who sent a commitment letter last month, and we expect more companies to join in the future. The committed participants bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program. The group includes members committed to or leaning toward both EDAM and Markets+, as well as some who have not indicated they will join a day-ahead market. The committed participants are:

- Arizona Public Service Company
- Avista Corp
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- PUD #2 of Grant County
- Idaho Power
- NorthWestern Energy
- Powerex Corp.
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Tacoma Power
- The Energy Authority, Inc.
- Tucson Electric Power

The following companies provided formal notice of intent to exit:

- Calpine Energy Solutions
- Eugene Water & Electric Board
- NV Energy
- PacifiCorp
- Portland General Electric Company
- Public Service Company of New Mexico

To all participants, thank you for your efforts in the last six years to build WRAP into a program that can help the region tackle the significant challenge of resource adequacy.

To our exiting participants, over the next two years, we encourage you to stay engaged in committees, task forces, and the stakeholder process to continue to evolve and improve WRAP and potentially resolve the concerns that prevented you from committing to binding operations at this time. As we have communicated previously, should your concerns be resolved, you have the option to rejoin the program and can commit to the Winter 2027/2028 season as late as September 15, 2026.

We have received a lot of positive outreach and support as we neared this deadline, and I will share just one example - part of a note we received from Lauren Tenney Denison, Director of Market Policy & Grid Strategy for Public Power Council. She wrote, "You have designed a remarkable program, from the ground up. WRAP has forever changed the way the West approaches markets and regional programs. There is a large and diverse footprint of entities committed to the binding season. That is a lot to be excited about."

I wanted you all to see this too because the congratulations for designing this program are for all of us and because there is a lot of progress to be excited about.

We look forward to continuing to work collaboratively to support reliability and resource adequacy across the West.

Rebecca Sexton
Chief Strategy Officer
WPP | 253-279-3002
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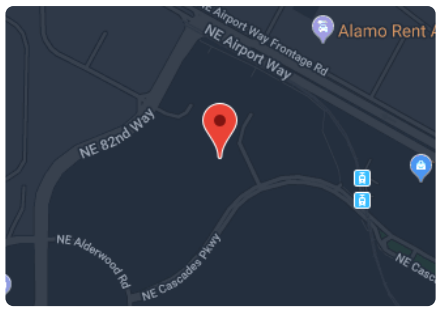

PROGRAMS

NEWS

EVENTS

CONTACT

DOCUMENTS

ABOUT

SIGN IN

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

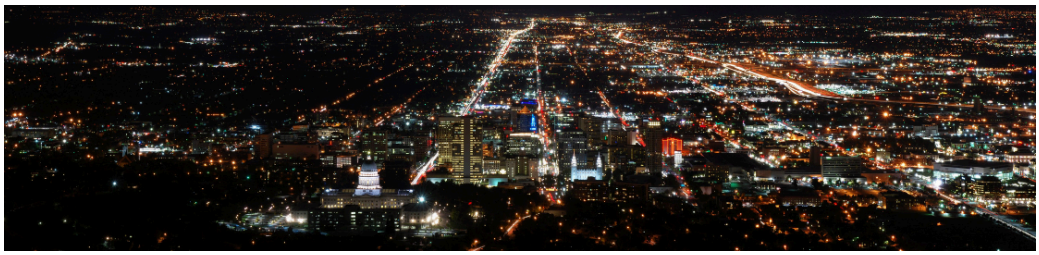
Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-149:
About WECC webpage

LOGIN



About WECC

The Western Electricity Coordinating Council (WECC) is a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.

WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the Regional Entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws.

There are six Regional Entities given authority by NERC and FERC. Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection. WECC's footprint

extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

Membership in WECC is open to all entities that meet the qualifications in the WECC Bylaws. WECC strives for transparency and open participation in all of its meetings and processes.

2024 State of the Interconnection Report

Our History

@ 2026 WECC

LEGAL

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-150:
NERC Rules of Procedure

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: November 28, 2023

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted.[1] Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

    2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

    2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

[1] When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the NERC *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

    3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in

each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment at any time or apply to change Segments as described in the *Development of the Registered Ballot Body* in **Appendix 3D**. In the event a change in corporate or organizational structure results in merged or affiliated entities having more than one membership in a particular Segment, the merged or affiliated entities shall withdraw the additional memberships before joining any new ballot pools or voting on any standards action as part of an existing ballot pool.

3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments periodically to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the

Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC standards staff shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual* and shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. NERC staff shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The NERC *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the NERC *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or

is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop New or Modified Reliability Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC, NERC shall within five (5) business days notify all other Applicable Governmental Authorities. Reliability Standards that are directed by an Applicable Governmental Authority shall be developed using the NERC *Standard Processes Manual*. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authority, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the waiver provisions of the NERC *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests

in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

    3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional

Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall

rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or

is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted

by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — Each Regional Entity that has Regional Criteria shall maintain a publicly-available, current catalog of its Regional Criteria. Regional Entities shall provide any Regional Criteria to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and

propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Reserved

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by NERC staff of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory and Board of Trustees Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps; provided that the Board of Trustees shall, to the extent feasible and consistent with its obligations and established deadlines, choose actions that seek to maximize stakeholder participation.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities or by the NERC Board of Trustees pursuant to its authority in Section 322. If the Board of Trustees is presented with a proposed Reliability Standard that fails to adequately address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or by the NERC Board of Trustees pursuant to its

authority in Section 322, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; (iii) use the input from the technical conference to revise the proposed Reliability Standard, as appropriate; and (iv) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective. In addition, the Board of Trustees may direct further revisions in accordance with Rule 322.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to take one of the following actions:

4.3.2.1 For a regulatory directive, the Board of Trustees may treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

4.3.2.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or the Board of Trustees, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory or Board directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of

Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective. In addition, the Board of Trustees may direct further work in accordance with Rule 322.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to take one of the following actions:

5.3.1 For a regulatory directive, the Board of Trustees may direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.3.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

322. Special Authority to Address Reliability Matters Necessary to Maintain the Reliability of the Bulk Power System

To meet NERC's statutory responsibility under Section 215 of the Federal Power Act to develop Reliability Standards that provide for an adequate level of reliability for the Bulk Power System, the Board of Trustees shall have the authority to direct the development of a new or revised Reliability Standard. The Board of Trustees will only exercise this authority in extraordinary circumstances, where the Board determines a directive is essential to provide for an adequate level of reliability for the Bulk Power System consistent with Section 215 of the Federal Power Act. This authority shall be in addition to the Board of Trustees' other authorities regarding Reliability Standards as provided in these Rules of Procedure and the Bylaws. In issuing such directives, the following process shall be used:

1. The Board of Trustees shall provide public notice of its intent to direct the development of a new or revised Reliability Standard to address a matter it has deemed essential to provide for an adequate level of reliability for the Bulk Power System. This notice shall take the form of a written document that includes, at a minimum, the following:

    1.1 the proposed date for issuing the proposed directive, which shall be no earlier than 60 days from the date of the notice, and the period for public comment, which shall be no less than 45 days;

    1.2 a description of the proposed directive, including any deadlines for standards development;

    1.3 the reliability basis for the proposed directive;

    1.4 the reasons why the Board has preliminarily determined that extraordinary circumstances exist, and that the proposed directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive; and

    1.6 An explanation of why the Board has preliminarily determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff.

2. NERC shall publicly post the notice and set a public comment period for the time described in the notice.

3. The Board of Trustees may direct the development of a new or revised Reliability Standard, as originally proposed or with modifications, if it determines that such action is just, reasonable, not unduly discriminatory, and in the public interest. This action shall take the take the form of a written determination containing, at a minimum, the following:

    1.1 the effective date of the directive;

    1.2 a description of the directive, including any deadlines for standards development;

    1.3 the reliability basis for the directive;

    1.4 the reasons why the Board has determined that extraordinary circumstances exist, and that the directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive;

    1.6 An explanation of why the Board has determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff; and

    1.7 a description of how the Board of Trustees considered any advice provided by the Member Representatives Committee, or any comments provided by the public, NERC standing committees, Applicable Governmental Authorities or other regulatory authorities, the Regional Entities, or NERC management.

4. Any person or entity with directly and materially affected interests in the subject of a Board of Trustees directive, including any nonprofit association representing members with such interests, may request the Board of Trustees reconsider or clarify its determination. Such request shall be submitted in writing within 30 calendar days of the issuance of the determination and contain, at a minimum, a description of the matter for which the entity is seeking reconsideration or clarification, the reasons therefor, and the interests that would be affected if the requested reconsideration or clarification is not granted. If the Board of Trustees does not act on the request within 30 days, it may be deemed denied. Unless

otherwise directed by the Board of Trustees, no deadline for action shall be stayed pending the disposition of any request for reconsideration or clarification.

5. NERC shall publicly post all Board of Trustees directives and any supporting documentation. This information shall become part of the record of development for the resulting Reliability Standard.

6. Where the Board of Trustees has determined to direct the development of a new or revised Reliability Standard, NERC Staff shall prepare a Standards Authorization Request for submission to the Standards Committee.

7. Reliability Standards that are directed by the Board of Trustees shall be developed using the NERC Standard Processes Manual. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Board of Trustees, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in its directive, then the Board of Trustees may, in its discretion, apply Rule 321 of these Rules of Procedure.

SECTION 400 — COMPLIANCE MONITORING AND ENFORCEMENT

401. Scope of the Compliance Monitoring and Enforcement Program

1. **Components of the Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a Compliance Monitoring and Enforcement Program (CMEP) to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North America in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC or other legal instrument approved by an Applicable Governmental Authority) has been given enforcement authority.

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users are required to comply with all approved Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC or the Compliance Enforcement Authority (CEA) such Documents, data, and information as is necessary to monitor and enforce compliance with the Reliability Standards. NERC and the CEA will define the data retention and reporting requirements.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer the CMEP provided in these Rules of Procedure.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity if NERC does not have a delegation agreement with a Regional Entity, the Regional Entity or NERC terminates the delegation agreement, or the Regional Entity does not administer the CMEP in accordance with the delegation agreement or other applicable requirements.

    5.1 In the circumstances outlined above, the following will apply:

        1. This monitoring and enforcement can be coordinated with staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant information regarding Registered Entities in the geographic footprint or for which the Regional Entity has CMEP responsibilities under coordinated oversight of Registered Entities, as specified in a termination agreement.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies consistent with Section 1107 of the Rules of Procedure.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the CMEP within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify ERO and Regional Entity-specific risk elements, together with related Reliability Standards and Requirements are to be considered to prioritize CMEP activities. NERC coordinates with the Regional Entities to identify the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual ERO CMEP Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which are incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC and Regional Entities shall coordinate to maintain a record of each compliance submission, including potential noncompliance with approved

Reliability Standards; associated Penalties, sanctions, Remedial Action Directives, and settlements; and the status of Mitigating Activities.

10. **Confidential Information** — The types of CMEP information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500.

    The disclosure by the CEA or NERC of any CMEP Confidential Information shall follow Section 1500.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with the resolution of a potential noncompliance with a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a potential noncompliance or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the requirements, rules, and regulations of the Applicable Governmental Authority and the confidentiality requirements of these Rules of Procedure, publicly post information on each such noncompliance, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedure.

    11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the publicly posted information. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

    11.2 Subject to the disclosure requirements of the Applicable Governmental Authority and redaction of Critical Energy Infrastructure Information, Critical Electric Infrastructure Information, or other Confidential Information, for each resolved noncompliance submitted to the Applicable Governmental Authority, the public posting shall include: a) the name of any relevant entity, b) the nature, time period, and circumstances of the noncompliance, c) any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity, and d) sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Review of Noncompliance** — NERC staff shall periodically review and analyze reports of noncompliance to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Compliance Monitoring and Enforcement Program

1. **Oversight** — NERC shall oversee each Regional Entity that has been delegated authority. The objective of this oversight is to ensure that the Regional Entity

carries out its obligations under the CMEP in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's execution of the CMEP. Oversight by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance metrics, risk-based monitoring activities, and performance reports. Through this oversight, NERC evaluates the Regional Entity's effectiveness and implementation of the CMEP using, among other things, the criteria developed by the NERC Compliance and Certification Committee.

1.1 **Annual ERO CMEP Implementation Plan** — NERC and the Regional Entities will maintain and update an ERO CMEP Implementation Plan. The ERO CMEP Implementation Plan reflects ERO and Regional Entity-specific risk elements that CEAs should prioritize for oversight of Registered Entities.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity implements the CMEP. The audit shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreements, directives in effect pursuant to the delegation agreements, the approved annual ERO CMEP Implementation Plan, required CMEP attributes, and NERC CMEP guidance and procedures. The audit shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 4.1.4 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to

verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's implementation of the CMEP.

2. **Consistency in Regional Implementation of the Compliance Monitoring and Enforcement Program** — To provide for consistency and fairness of the processes used for Regional Entity findings of compliance and noncompliance and the application of Penalties and sanctions for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single CMEP, which is incorporated into these Rules of Procedure as **Appendix 4C**. Any differences in CMEP methods, including determination of noncompliance and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall periodically conduct Regional Entity CMEP manager meetings. These meetings shall identify and resolve CMEP differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Noncompliance Disclosure** — NERC shall follow the process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — The CEA shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Remedial Action Directives may be issued by a CEA that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert noncompliance with a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections

408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

7. **Conflict Disclosure** — NERC shall disclose to the Applicable Governmental Authority any potential conflicts between a market rule and the enforcement of a Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the CMEP, NERC and Regional Entities, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during CMEP activities.

    8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for all participants in CMEP activities.

    8.2 A participant's failure to follow the code of conduct or Confidential Information provisions of these Rules of Procedure may result in that person and any member organization with which the person is associated losing access to Confidential Information on a temporary or permanent basis and being subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future CMEP activities. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to participants in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Implementation of the Compliance Monitoring and Enforcement Program

Each Regional Entity shall (i) conform to and comply with the CMEP, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its CMEP activities shall exhibit independence, meaning the Regional Entity shall be organized so that its CMEP activities are carried out separately from other activities of the Regional

Entity. The CMEP activities shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity shall exercise the responsibility and authority in carrying out the delegated functions of the CMEP in accordance with delegation agreements and **Appendix 4C**.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the CMEP, a Regional Entity shall not sub-delegate its CMEP duties to entities or persons other than the Regional Entity Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** Unless the Regional Entity has elected to participate in the Consolidated Hearing Process, the Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the CMEP.

6. **Regional Entity Staff Independence** — The Regional Entity Staff, collectively, shall be capable and required to: a) make all determinations of compliance and noncompliance; b) determine Penalties, sanctions, and Remedial Action Directives; and c) review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

6.2 Regional Entity Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes, make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure and the delegation agreement

6.5 Contracting with independent consultants or others working for the Regional Entity shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals shall be considered as augmenting Regional Entity Staff under these Rules of Procedure.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in CMEP activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than Regional Entity staff. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized

so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Antitrust Provisions** — Each Regional Entity's CMEP activities shall be structured and administered to abide by United States antitrust law and Canadian competition law.

9. **Information Submittal** — All Bulk Power System owners, operators, and users responsible for complying with Reliability Standards within the Regional Entity shall submit timely and accurate Documents, data, and information when requested by the Regional Entity or NERC. Where appropriate, Submitting Entities should comply with the requirements of Section 1500 in submitting such Documents, data, and information. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

9.1 Each Regional Entity has the authority to collect the necessary Documents, data, and information to determine compliance and shall develop processes for gathering Documents, data, and information from the Bulk Power System owners, operators, and users the Regional Entity monitors.

9.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.9 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

9.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

9.4 Regional Entities shall notify NERC of noncompliance with Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

9.5 As requested by the CEA, a Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan or conduct Mitigating Activities in accordance with **Appendix 4C**. The Regional Entity Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

9.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all Self-Reports to the Regional Entity, including Documents, data, and information provided with the Self-Report.

9.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

10. **Compliance Monitoring of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program for risk-based compliance monitoring, to include Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**.

10.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years.

11. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and Documents, data, and information obtained from such processes, are to be non-public and treated in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity, or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as such disclosures are in accordance with Section 1500 and Appendix 4C of these Rules of Procedure.

12. **Critical Energy Infrastructure Information and Critical Electric Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will

be identified and protected from public disclosure as Confidential Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information or Critical Electric Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

13. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties, and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

14. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System

owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

14A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

14B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee ("Compliance Committee") will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity from which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

404. NERC Monitoring of Compliance for Bulk Power System Owners, Operators, or Users

1. **NERC Obligations** —NERC will directly monitor Bulk Power System owners, operators, and users for compliance with Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the CEA described in **Appendix 4C**. Compliance matters contested by Bulk Power

System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Appeals Process** — Any Bulk Power System owner, operator or user found by NERC to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring NERC's Compliance with the Rules of Procedure

The Compliance and Certification Committee shall monitor NERC's compliance with its Rules of Procedure for the Reliability Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs in accordance with this section and Section 506. The Compliance and Certification Committee's monitoring shall not be used to circumvent the appeals processes established for those programs. The Compliance and Certification Committee shall use independent expert monitors with no conflict of interest, real or perceived. Compliance and Certification Committee findings shall be addressed with the NERC Board of Trustees and other appropriate Board committees.

406. Independent Audits of the Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of the Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the NERC Board of Trustees in coordination with the Compliance and Certification Committee. The audit shall be conducted by independent expert auditors as selected by the NERC Board of Trustees. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board of Trustees.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entities in implementing the Compliance Monitoring and Enforcement Program and the effectiveness of the program in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with Appendix 4C.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the Compliance Monitoring and Enforcement Program, the administrators of the Compliance Monitoring and Enforcement Program shall provide a written response and plan to the NERC Board of Trustees within 30 days of the release of the final audit report to the NERC Board of Trustees or other appropriate Board committee. NERC will post the written response and plan for public viewing when authorized by the NERC Board of Trustees or other

appropriate Board committee. NERC will post the written response and plan for public viewing.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions, and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination: a) is supported by a sufficient record compiled by the Regional Entity; b) is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance, and directions issued by NERC pursuant to the delegation agreement; and c) is consistent with Penalties, sanctions, and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction, or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a Notice of Penalty and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 30 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 30 days after receiving a copy of the notice of challenge, the NERC

Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — For matters subject to its review, the Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, NERC may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the CEA, or an owner, operator, or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Board of Trustees Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Board of Trustees Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Board of Trustees Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of: a) any action or inaction; b) any agreement reached in resolution of the dispute; or c) any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement. The request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy, or procedure, the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Board of Trustees Compliance Committee.

2. The Board of Trustees Compliance Committee may accept or reject a certification of a question for decision. If the Board of Trustees Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Board of Trustees Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee may also request, or provide an opportunity for, the NERC Compliance department, the NERC Enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda are filed in accordance with the schedule, the Board of Trustees Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Board of Trustees Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Board of Trustees Compliance Committee's decision.

5. The Board of Trustees Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9, and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Staff, and all other Participants in the Hearing Body proceeding,

no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Board of Trustees Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee shall issue a written decision on the appeal; provided, that if the Board of Trustees Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Board of Trustees Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Board of Trustees Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Board of Trustees Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Board of Trustees Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Board of Trustees Compliance Committee to FERC

or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules, and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules, or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) Entities may address registration obligations for applicable function types using a Joint Registration Organization (JRO), in lieu of each of the JRO's parties'entities being registered individually for one or more functions. Refer to Section 507.

   (c) Entities may each register using a Coordinated Functional Registration

(CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability

Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. The NERC programs shall:

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

2.1 Evaluate the entity's tools, personnel, facilities, and processes used to perform the duties and tasks identified in and required by the Reliability Standards. The entities currently requiring Certification include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Certify each applicant's ability to perform the function for a specified Area.[3]

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements,

[3] When the term "Area" is used and capitalized it is being used in the certification context, and is inclusive of terms currently defined in NERC Glossary of Terms and Appendix 2 of the ROP, specifically, "Balancing Authority Area," "Reliability Coordinator Area," or "Transmission Operator Area."

and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections VI and VII, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with its members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be provided to the NERC Board of Trustees or its appropriate committees, and posted for public viewing. Confidential Information shall be handled in accordance with the NERC Rules of Procedure Section 1500, *Confidential Information*.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all function type(s) that it performs itself, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more parties to the agreement for one or more function type(s) for which such parties would otherwise be required to register. The Lead Entity thereby, accept on behalf of such parties all compliance responsibility for the function types(s) covered by the JRO registration, including all reporting requirements. The Lead Entity of a JRO must execute a written agreement with the parties on whose behalf it registers that: (1) governs the relationship between the parties; (2) addresses the function type(s) described within Appendix 5B for which the Lead Entity is registering for and taking responsibility, and which would otherwise be the responsibility of one or more of the other parties to the JRO; (3) identifies which entity is the Lead Entity and a point of contact within the Lead Entity; and (4) identifies a point of contact for each of the parties to the JRO.

2. For every JRO, the written agreement must be submitted to the appropriate Regional Entity for its retention. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity shall have responsibility for reviewing or approving any such agreement, other than to verify that the agreement addresses the function type(s) consistent with the Lead Entity's Registration.

3. The JRO Registration data must include all Registration and Certification information as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact identified for the Lead Entity of the JRO.[4]

4. The Regional Entity shall notify NERC when it registers a Lead Entity of a JRO. The notification will identify the point of contact and the function type(s) for which the Lead Entity of the JRO is registered on behalf of the JRO parties and a point of contact for each of the JRO parties.

[4] The primary compliance contact for the Lead Entity of a JRO can be the same person who serves as the point of contact for the Lead Entity of the JRO. However, it is not required that the same person serve as both the primary compliance contact and the point of contact.

5. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs, the Lead Entities, the JRO parties,es and the function type(s) for which the Lead Entity of the JRO has registered for each partythat. It is the responsibility of the Lead Entity of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

6. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the JRO and can request such additional information as the Regional Entity deems appropriate.

7. The Regional Entity's acceptance of a Lead Entity's registration as part of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the Lead Entity of the JRO meets the Registration requirements of Section 501(1.4).

8. NERC shall maintain, and post on its website, a listing of all JROs, Lead Entities, JRO parties, and the function type(s) for which the Lead Entity of the JRO has registered for each party.

9. The Lead Entity of the JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

10. Nothing in Section 507 shall preclude any party to a JRO from registering on its own behalf and undertaking full compliance responsibility for the function type(s) for which the Lead Entity of the JRO has registered. Such registration shall include submission of data or information that includes any documentation that the agreement supporting the JRO has been terminated as to the registering party. In addition to any notification requirements contained within the written agreement, a JRO party, that registers as responsible for any function type(s) for which the Lead Entity of a JRO was previously responsible shall inform the Lead Entity of the JRO and/or other parties once its Registration has been accepted by the Regional Entity.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities using a CFR must register for the function associated with the CFR. The CFR submission to the Regional Entity must include a written agreement that: (1) governs itself; (2) specifies the entities' respective compliance responsibilities; (3) identifies which entity is the Lead Entity, a point of contact within the Lead Entity, and a point of contact for each of the parties to the CFR The Lead Entity identified for each CFR is responsible for providing the written agreement between the parties, including submitting updates for currently active CFRs to the Regional Entity related to the CFR Registration; and (4) lists one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type.

2. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the function type for which the parties are registered and the responsibility(ies) which are addressed through the CFR.

3. The CFR Registration data must include all Registration and Certification information and data, as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance, as it relates to the CFR. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact(s) identified for each of the CFR parties.

4. Each party to a CFR shall have compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements for which it has registered pursuant to the CFR.

5. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts, and the notification shall include identification of the Lead Entity of a CFR, the function type that the CFR addresses, a point of contact for each of the CFR parties, and any updates to currently active CFRs.

6. For purposes of Compliance Audits, the Regional Entity shall keep a list of all CFRs, the Lead Entities, the CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties.

7. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the CFR and can request such additional information as the Regional Entity deems appropriate.

8. The Regional Entity's acceptance of a Lead Entity's registration as part of a CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the CFR meets the Registration requirements of Section 501(1.4).

9. NERC shall maintain, and post on its website, a listing of all CFRs, the Lead Entity of CFRs, CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

10. Any noncompliance shall be investigated in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*.

11. Nothing in Section 508 shall preclude a party to a CFR from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards to which a CFR is applicable. Such

registration shall include submission of data or information that includes any documentation that the agreement supporting the CFR has been terminated or revised as to the Reliability Standards for which the registering party is now taking compliance responsibility. In addition to any notification requirements contained within the written agreement, an entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the Lead Entity of the CFR and/or other parties once its Registration has been accepted by the Regional Entity.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION AND CREDENTIAL MAINTENANCE PROGRAM

601. Scope of Personnel Certification and Credential Maintenance Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification and Credential Maintenance Program to:

1. provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam;

3. award the system operator Certification Credential to individuals who pass the exam; and,

4. prescribe requirements for System Operators to maintain their Certification Credential.

The NERC Personnel Certification and Credential Maintenance Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that both establishes the policies, sets fees, and monitors the performance of the Personnel Certification and Credential Maintenance Program for system operators.

602. Structure of ERO Personnel Certification and Credential Maintenance Program

1. PCGC shall develop a system operator program manual, approved by the NERC Board of Directors, which outlines the following:

   1.1 requirements for administering the system operator examinations;

   1.2 requirements for exam eligibility;

   1.3 requirements for awarding the Certification Credential;

   1.4 requirements for Certification Credential maintenance;

   1.4.1 NERC requires a system operator to earn CE Hours in NERC-Approved Learning Activities within the three-year period preceding

the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual.

1.4.2 NERC requires a system operator to request a renewal and submit the appropriate fee for Certification renewal evaluation.

1.5 dispute resolution procedures; and

1.6 disciplinary action guidelines.

2. PCGC shall develop a Credential Maintenance Program and maintain an accompanying manual, which outlines the following:

2.1 requirements for approving contining education Providers and Learning Activities;

2.2 requirements for auditing continuing education Providers and Learning Activities;

2.3 multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and credential maintenance disputes; and,

2.4 requirements on fees for continuing education Providers and Learning Activities.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the

required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC

chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

    5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

    1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

1.1 Adopt and implement a formal policy of periodic review of exams to assess ongoing relevance to knowledge and skill needed in the discipline; and

1.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

    1.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

    1.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

    1.3 The PCGC shall dictate how long examination records are kept in their original format; and

    1.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

610. [PLACEHOLDER]

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. [PLACEHOLDER]

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall participate in and, where appropriate, coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America. NERC shall, where appropriate, take a leadership role in Critical Infrastructure protection of the electricity sector to help reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electricity Information Sharing and Analysis Center (E-ISAC)

    1.1 NERC shall operate the E-ISAC on behalf of the electricity sector. In 1998, the U.S. Secretary of Energy asked NERC to serve as the information sharing and analysis center for the electricity sector, in implementation of Presidential Decision Directive 63, as part of a public/private partnership to deal with matters related to infrastructure security.

    1.2 The E-ISAC gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity sector, across interdependent sectors, and with government partners. The E-ISAC, in collaboration with the United States Department of Energy (DOE) and the Electricity Subsector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity sector and enhances the sector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

    1.3 NERC shall improve the capability of the E-ISAC to fulfill its mission.

    1.4 NERC shall work closely with governmental agencies, including, among others, DOE, the United States Department of Homeland Security, Natural Resources Canada, and Public Safety Canada.

    1.5 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.6 NERC shall coordinate with the ESCC and the Government Coordinating Council.

1.7 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, other ISACs, and the National Infrastructure Advisory Council.

1.8 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

1.9 As part of the E-ISAC's efforts to fulfill its mission, it may issue, as circumstances warrant, written communications, referred to as All Points Bulletins (APBs), to disseminate critical security information rapidly to electricity sector asset owners and operators as security threats and attacks develop, and critical, time-sensitive security information becomes available. The E-ISAC shall share all APBs with Federal Energy Regulatory Commission staff no later than at the time of issuance.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, through identification, protection, detection, response, and recovery functions.

2.2 NERC shall consider security along-side considerations of reliability and resiliency of the Bulk Power System.

2.3 NERC shall keep abreast of the changing threat environment through collaboration with appropriate government agencies.

2.4 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methods, and assess effectiveness of physical and cyber protection measures.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness of security matters and respond to the security needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and endeavor to improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.10 NERC shall improve methods to assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[5] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[5] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Electric Infrastructure** means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

4. **Critical Electric Infrastructure Information** means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

5. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

6. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

7. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the

"Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls, and by adding any labels required by rules or regulations of an Applicable Governmental Authority. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity. Commission regulations regarding access to Critical Electric Infrastructure Information or Critical Energy Infrastructure Information will also apply as appropriate when the Commission is the Submitting Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality

in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement provided by NERC.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion

of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Resolved Noncompliance** — Nothing in this Section 1500 shall prohibit the disclosure of a noncompliance at the point when the matter is filed with an Applicable Governmental Authority, a Registered Entity admits to the violation, or the Registered Entity and the CEA resolve the noncompliance in accordance with Appendix 4C.

2. **Information Exchange** — NERC and the Regional Entities are authorized to exchange Confidential Information to perform their respective statutory and delegated functions, including, but not limited to, evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information consistent with the delegation agreement.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses Confidential Information may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.