Pacific Northwest Power Supply Adequacy Assessment for **2027**

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

Pacific Northwest Power Supply Adequacy Assessment for 2027

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This report summarizes the Northwest Power and Conservation's assessment of the aggregate regional power supply's adequacy for the 2027 operating year (October 2026 through September 2027). Analytical results are based on the Council's redeveloped GENESYS model, which performs a Monte-Carlo[1] 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.

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. In 2011, the Council adopted a 5 percent annual loss-of-load probability (LOLP) as its measure for adequacy. The power supply is deemed to be adequate when the likelihood of one or more shortfalls occurring during the year is no greater than 5 percent. While the LOLP has proven to be a good measure of resource adequacy, the Council believes a more comprehensive set of metrics are needed for the assessment. These include shortfall frequency, duration, and magnitude.

Metrics chosen for the enhanced assessment are described later in this report. Provisional limits (or thresholds) for the new metrics were used for this assessment, with the understanding that those limits will be reevaluated in the coming year. The Council reviewed all analytical results from many potential future scenarios and considered all stakeholder feedback to make an informed judgement regarding the adequacy of the 2027 power supply.

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.

[1] In this context, the Monte-Carlo GENESYS model simulates the hourly operation of the region's power system many times, with different combinations of future conditions (river flow, demand, wind and solar generation, and generator forced outages) for each simulation.

Executive Summary

For the regional power supply to be adequate in 2027, the region will need to develop new resources at least as aggressively as the 2021 Power Plan outlines. The 2027 regional power supply would not be adequate if the region relied solely on existing resources, existing reserve levels, and with no new energy efficiency measures. If demand growth remains consistent with the plan's baseline forecast, then the power supply *would* be adequate with resources and reserves identified in the 2021 Power Plan's resource strategy. However, if future electricity market supplies are significantly limited, if new policy commitments to electrification accelerate demand growth, or if major resources are retired earlier than expected without replacement, then additional resources and reserves will be required to maintain system adequacy, as detailed in the 2021 Power Plan.

To better assess customer risk, the Council examined additional adequacy measures, in conjunction with its current loss of load probability (LOLP) adequacy metric. The additional metrics provide information about the frequency, duration, and magnitude of potential shortfall events as follows:

- Loss of load events, or LOLEV, sets a limit for the expected frequency of shortfall events to prevent an excessively frequent use of emergency measures
- Duration Value at Risk sets a limit for shortfall duration during rare (once per 40 year) events
- Peak and Energy Value at Risk set limits for the maximum capacity and energy shortfalls during rare (once per 40 year) events

Using this full suite of metrics, along with provisional thresholds that postulate the tolerable range of risk to avoid, the Council was able to provide a more complete assessment of system adequacy.

The 2021 Power Plan's resource strategy recommends that between 750 and 1,000 average megawatts of energy efficiency, at least 3,500 megawatts of renewable resources, and 720 megawatts of demand response be acquired by 2027.[2] The plan also highlighted the importance and need for achieving the increasing reserves requirement to respond to the growing short-term uncertainty in generation from significant additions of variable energy

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[2] See pages 46-47 in the 2021 Power Plan Section 6: Resource Development Plan.

resources (primarily solar and wind generation).[3] As part of this assessment, the resource strategy was tested under a large range of potential future conditions. Like the plan, this assessment confirms that an adaptive approach is required to maintain adequacy, from the perspective of ensuring that the full suite of adequacy metrics remain within their provisional thresholds.

This assessment finds that the 2021 Power Plan resource strategy is effective at eliminating nearly all summer shortfalls, when resource needs peak in the rest of the Western grid. Implementing the strategy does not eliminate winter shortfall events, but it does mitigate them by reducing shortfall event magnitude and shortening event duration to only a few hours during the morning and evening ramps.

New clean energy policies will result in a significant level of renewable generation built throughout the west, both within and outside the region. This projected renewable resource acquisition changes market supply and demand dynamics because the hourly pattern of renewable generation does not always coincide with the hourly pattern of greatest energy need. This leads to periods during certain times of the day with a surplus of very inexpensive market supply (mostly solar).

During these periods, due to this increased market supply and persistence of lower prices, the Northwest is expected to consistently import more power than it has in the past. However, there also will be times within the same day, often during morning and evening ramps, when available market supply is smaller and more expensive than in the past, providing an opportunity for the Northwest to export to other regions in the West. The ability of Northwest hydroelectric and thermal systems to ramp up and down to respond to those changing market dynamics requires appropriate market signals, either from a regional reserve pooling effort or from an enhanced market structure.

In light of these changing dynamics, this assessment considers a number of potential market uncertainties. The findings indicate that out-of-region market supply uncertainties have, for the most part, a minimal effect on regional adequacy, assuming the Council's current market reliance limits. However, under certain future scenarios, results show regional adequacy levels becoming borderline or unacceptable. These scenarios include futures with high gas prices, continued supply chain challenges, increased demand (due to accelerated electrification without a supply and reserve increase), and lower than expected West-wide renewable generation acquisition.

[3] See pages 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 for a description of the three methods suggested in the plan.

As in the plan, this assessment found risk factors to monitor when determining how to implement and adapt the resource strategy to the wide range of uncertainties the region faces. If regional planners observe increased demand due to accelerated electrification in any part of the region without an associated increase in resources and reserves, and/or resources of significant size are retired without replacement, the risk of adequacy issues increases significantly.

The plan analysis identified these same risks and indicated that significantly larger builds of renewable resources and accompanying reserves would be required to maintain an adequate system.[4] The resource strategy recommends that jurisdictions pursuing aggressive emissions reductions should evaluate adding more renewables to avoid these risks.[5] The plan also recognized that additional energy efficiency would likely be cost-effective for those jurisdictions pursuing electrification policies.[6,7]

If the region is ineffective at coupling the investment recommendations from the plan with a coordinated reserve pooling effort of sufficient size to match the increase in the short-term uncertainty from load and generation, the region will be more susceptible to adequacy risk from the market.[8]

During this time of significant uncertainty, the Council will continue to track these risk factors and revisit them in the annual adequacy assessment and its other efforts as part of the ongoing 2021 Power Plan implementation. In addition, the Council will continue to host discussions exploring the provisional thresholds and interpretation of a multi-metric approach to assessing adequacy with stakeholders to better characterize and help the region address the evolving adequacy issues as they arise.

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[4] See page 89 in the 2021 Power Plan Section 6: Resource Development Plan for additional analytical results.

[5] See page 46 in the 2021 Power Plan Section 6: Resource Development Plan for a discussion of generation resource recommendations.

[6] See page 39 in the 2021 Power Plan Section 5: Energy Conservation Program, the Model Conservation Standard on Conversion to Electric Space Conditioning and Water Heating.

[7] While not explicitly identified in the 2021 Power Plan Resource Strategy, analysis demonstrates that jurisdictions with increased demand would also have an increase in demand response potential from time of use rates and demand voltage regulation, the two types of demand response products recommended by the plan resource strategy.

[8] Monitoring the market enhancements and regional collaboration efforts will be key to evaluating whether the region is overly relying on market purchases to mitigate increasing regional reserve need.

Improved Metrics for Adequacy

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard[9] to "provide an early warning should resource development fail to keep pace with demand growth." The standard also tests the power plan's resource strategy to ensure that it will provide an adequate future power supply. A power supply is deemed to be adequate when its annual Loss of Load Probability (LOLP) is 5 percent or less; that is, when the likelihood of having one or more shortfalls during an operating year is less than or equal to 5 percent.

While the probabilistic LOLP metric is a better measure of adequacy than the deterministic load/resource balance (historically used in the region), it has limitations. For example, it provides no indication of shortfall magnitude, duration, or frequency. It also does not indicate the timing (or seasonality) of shortfalls. Furthermore, it cannot differentiate among power supplies with a 5 percent LOLP that have vastly different shortfall magnitudes, durations, and/or frequencies. A 5 percent LOLP means that the simulated operation of the power supply yields only one year out of 20 with shortfalls. Thus, two power supplies that meet this criterion would both be considered adequate, even though during the shortfall year, one system may show only a single shortfall while the other shows multiple shortfalls.

The Council recognizes that today's power system is very different from that of 1980, when the Council was created by Congress. 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.

An adequacy standard consists of one or more metrics (measures) with corresponding limits for those metrics. For example, the Council's current standard uses the annual LOLP metric and sets its limit to 5 percent. To better assess adequacy, the Council developed a new comprehensive multi-metric standard to meet the following objectives:

- Prevent excessively frequent use of emergency measures
- Limit occurrences of very long shortfall events
- Limit occurrences of big capacity shortfalls

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[9] "A New Resource Adequacy Standard for the Pacific Northwest," Council Document Number 2011-14, 12/6/2011 https://www.nwcouncil.org/sites/default/files/2011_14_1.pdf

- Limit occurrences of big energy shortfalls

A detailed description of the proposed metrics is provided below. Provisional limits for these metrics will be used until further review of the GENESYS adequacy model is complete and after additional stakeholder feedback.

Loss of Load Events (LOLEV) to prevent excessively frequent use of emergency measures

Because of the difficulty involved, emergency measures (actions utilities can take to avoid a loss of service) are not included in the Council's adequacy model. Such measures include the use of undeclared (usually high cost) resources; high-cost market purchases; demand buy-back provisions; use of industry backup generators; and demand reduction protocols.

Thus, a simulated shortfall is not equivalent to an actual curtailment of service. The frequency of shortfalls, however, is equivalent to the frequency of using emergency measures. To prevent an overly frequent use of emergency measures, a limit can be set for the frequency of simulated shortfalls.

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.

The provisional limit for this metric ranges from 0.1 to 0.2 shortfall events per year (or one to two shortfall events per 10 years). For comparison to other standards that use this metric, the Western Power Pool's standard for its Western Resource Adequacy Program allows no more than one event day[10] per 10 years. Seattle City Light's standard allows no more than one bad[11] event per five years (or two bad events per 10 years). Tacoma Power's standard doesn't allow any event to occur more than once per five years or twice per 10 years.

Duration Value at Risk (VaR) to limit occurrences of very long shortfall events

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

[10] An "event day" is a day with one or more shortfall events. The WRAP standard limits the Loss of Load Expectation (LOLE) to one event day per 10 years. In this case the LOLE is the frequency of event days and not the frequency of shortfall events.

[11] For Seattle City Light, a "bad" event is one whose loss of service is 200 average megawatts or greater or whose duration is four hours or greater.

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 (or zero if there is no shortfall). The ***Duration VaR$_{97.5}$*** is the 97.5th highest duration from that record. 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 or twice per 10 years), it represents the risk of a real curtailment and not just a shortfall.

The provisional limit for this metric ranges from 8 to 12 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.

<u>Peak Value at Risk (VaR)</u> to limit occurrences of big capacity shortfalls

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 supply'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 is 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 zero if there is no shortfall). The ***Peak VaR$_{97.5}$*** is the 97.5th highest single-hour shortfall from that record. Choosing the 97.5th percentile limits the risk of an excessively 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 emergency measure capability, whereas the LOLEV frequency represents the risk of using emergency measures too often.

The provisional 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 $VaR_{97.5}$ 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 provisional limit for this metric ranges from 2,000 to 3,000 megawatts based on the assumption that, during an emergency, the region could acquire 1,000 to 1,500 megawatts of market capacity (albeit at very high prices) and 1,000 to 1,500 megawatts of emergency demand response.

Energy Value at Risk (VaR) to limit occurrences of big energy shortfalls

The region's power supply continues to be energy limited because hydroelectric resources make up the lion's share of the supply. It is very important to include a metric to protect against excessively high 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 Value at Risk (VaR) for energy shortfall at the 97.5^{th} 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*** $\boldsymbol{VaR_{97.5}}$ is the 97.5^{th} highest total annual unserved demand from that record. Choosing the 97.5^{th} percentile limits the risk of an excessively high annual energy shortfall to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (no more than once or twice per 10 years), it represents the risk of a real curtailment and not just a shortfall.

The provisional 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 $VaR_{97.5}$ 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.

But because of the difficulty in accurately assessing the amount of available emergency energy, alternative approaches can be used to set the $VaR_{97.5}$ limit. For example, some utilities set a limit on the tolerable amount of <u>average</u> annual unserved load (referred to as the expected unserved load or EUE). The $VaR_{97.5}$ limit, however, sets the <u>tail-end</u> annual unserved load tolerance; that is, for high-shortfall years that occur only once per 40 years. If the probability distribution for annual unserved load were known, then the tail-end limit could be estimated relative to an accepted EUE limit.

This and other potential methods of setting the $VaR_{97.5}$ limit will be explored by the Council and its advisory committees. In the meantime, the limit for this metric is approximated, if only 500 to 1,000 megawatt-hours per hour of emergency energy is available over an extended period, such as over the 8 hours representing the low end of the Duration $VaR_{97.5}$ adequacy limit. The provisional limit for this metric is assumed to range from 4,000 to 8,000 megawatt-hours.

Identifying the Timing (Seasonality) of Shortfalls

The Council's current annual LOLP standard does not indicate the seasonality of potential shortfalls. The decision to not use seasonal LOLP limits was originally based on the assumption that the timing of shortfalls was immaterial; that is, regardless of when shortfalls occurred, it was the magnitude of the shortfall that informed the solution. The same assumption is made for the new standard, meaning that the peak and energy VaR metric limits will be based on annual values. Monthly values for those metrics and others will be reported simply to provide additional information.

However, seasonal limits for the duration, peak and energy VaR metrics should be implemented if emergency measure capability varies significantly by month or season.

Table 1. Summary of Proposed New Adequacy Metrics

Metric	Definition and Adequacy Limit
LOLEV (Events/year)	Loss of Load Events = Expected number of shortfall events per year (total number of shortfall events divided by total number of simulations) Provisional limit ranges from 0.1 to 0.2 shortfall events/year
Duration $VaR_{97.5}$ (Hours)	Duration Value at Risk = Longest shortfall event for the 97.5th worst simulation year Provisional limit ranges from 8 to 12 hours
Peak $VaR_{97.5}$ (MW)	Peak Value at Risk = Highest single-hour shortfall for the 97.5th worst simulation year Provisional limit ranges from 2,000 to 3,000 megawatts
Energy $VaR_{97.5}$ (MW-hours)	Energy Value at Risk = Total annual shortfall energy for the 97.5th worst simulation year Provisional limit ranges from 4,000 to 8,000 megawatt-hours

The Council chose to include these additional metrics as part of its adequacy assessment, with the understanding that provisional limits for these metrics will be reviewed and amended, if necessary, after further review and stakeholder feedback. This proposed new adequacy standard will be evaluated over the next few years.

Based on this enhanced approach, the power supply is deemed to be inadequate if any one of the metric limits is violated. The level of inadequacy is assessed by the number and magnitude of violations. For example, a severe inadequacy occurs when all metric limits are exceeded or when violations are large. A marginal inadequacy occurs when some of the limits are exceeded, and violations are small. The system is deemed to be adequate when all metrics are within their adequacy limits.

Scenario Description

The development of scenarios to analyze the effects of market reliance, rapidly increasing demand and early retirement of major resources required modifying the baseline inputs of available resources, policies, loads, fuel prices, and transmission rating.

The first step in the adequacy assessment was determining the specific set of new resources (inferred by the plan) to test. The power plan's resource strategy recommends that between 750 and 1,000 average megawatts of energy efficiency; at least 3,500 megawatts of renewable resources; and 720 megawatts of demand response be acquired by 2027.[12] The strategy also emphasized the importance of increasing reserve requirements in response to the growing short-term uncertainty in generation from significant additions of solar and wind resources.

To determine the amount of new renewable resource capacity to test, the full range of regional renewable resource builds from all scenarios analyzed in the 2021 power plan was examined, as shown in Figure 1 below.

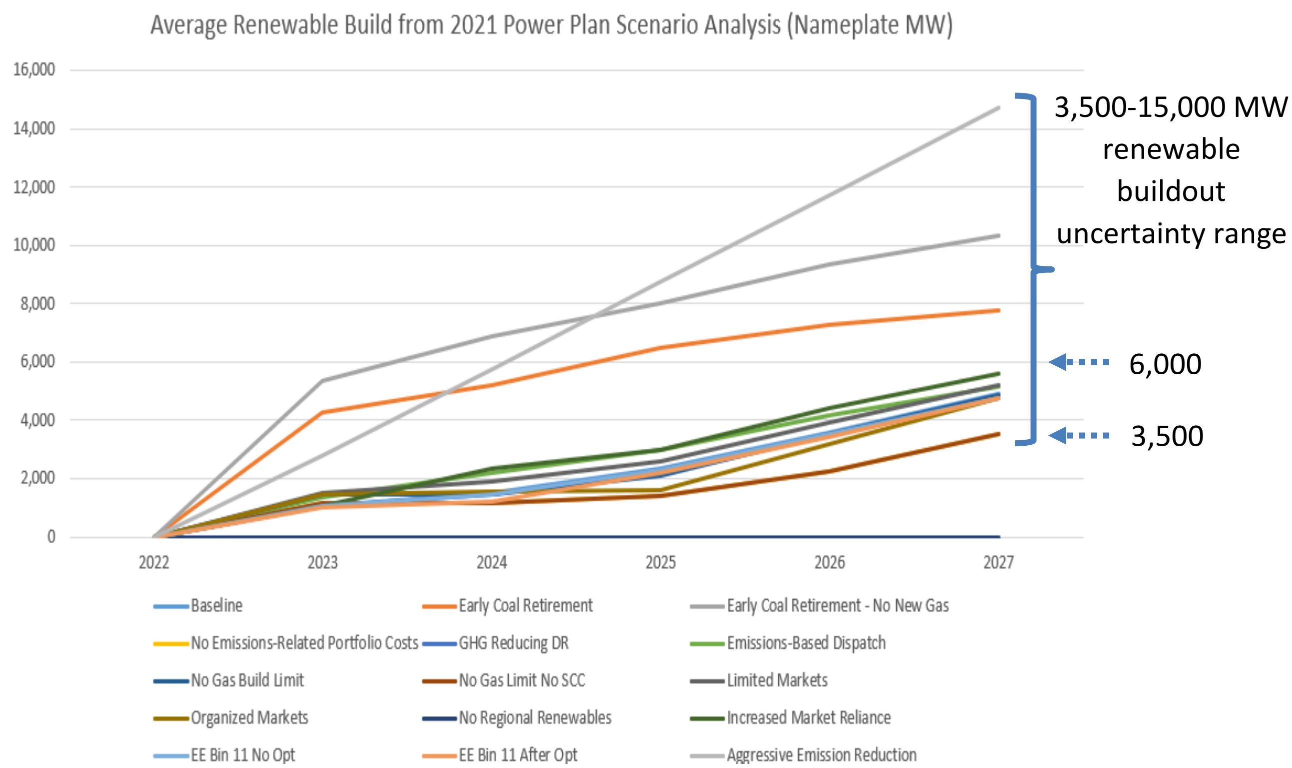

Figure 1. Average Renewable Build from 2021 Power Plan Scenario Analysis

The amount of additional renewable resource capacity needed by 2027 can range from 3,500 to about 15,000 megawatts, depending on the scenario. The plan's resource strategy specified a minimum need of 3,500 megawatts of renewable resources by 2027. The minimum resource strategy (Min RS) resource mix includes only 3,500 megawatts of renewable resources.

However, to capture the need for a wider range of potential future scenarios, the resource strategy reference (RS Ref) resource mix includes 6,000 megawatts of renewable resources. That amount of additional renewable resource capacity is sufficient for all but the early coal retirement, limited market, and aggressive emission reduction scenarios.

[12] See pages 46-47 in the 2021 Power Plan Section 6: Resource Development Plan.

Since the resource dataset was frozen for the development of the 2021 power plan, 590 megawatts of renewables have been built in the region. The 3,500 and 6,000 megawatts of renewable resource capacities in the Min RS and the RS Ref resource mixes were reduced to 2,910 and 5,410 megawatts respectively, and the 590 megawatts were included as part of existing resources.

For energy efficiency measures, the Min RS resource mix includes the lower end of the plan's recommended range, 750 average megawatts, and the RS Ref resource mix includes the high end of the range, 1,000 average megawatts. Both the Min RS and the RS Ref resource mixes include the 720 megawatts of cost-effective demand response identified in the power plan. [13]

Lastly, to be consistent with the 2021 power plan analysis, both the Min RS and the RS Ref strategies include 6,000 megawatts of incremental balancing reserves. The plan highlighted the need to increase balancing reserves to respond to added short-term uncertainty in generation from rapidly increasing additions of solar and wind resources.[14] The plan added an additional 3,100 megawatts of incremental reserves[15] over the 2,900 megawatts of reserves currently assumed to be held by regional utilities.

The following section offers brief descriptions to aid stakeholders in understanding the different conditions and assumptions of each scenario analyzed for this assessment. Each scenario title includes the resource strategy tested in parentheses.

1. <u>Resource Strategy Reference (RS Ref)</u>

The *RS Ref* scenario comprises the resource strategy of new renewables, energy efficiency, and demand response tested in all scenarios, aside from the no resource strategy, minimum resource strategy, and high Western Electricity Coordinating Council (WECC) demand scenarios. All scenarios have the same 6,000 megawatts incremental reserves. The reference strategy includes:

- 1,000 average megawatts of new energy efficiency measures
- 720 megawatts of new demand respond capabilities
- 5,410 megawatts of new renewables
- 590 megawatts of renewables added to the existing resource mix
- 6,000 megawatts of total Incremental reserves

[13] See page 47 in the 2021 Power Plan Section 6: Resource Development Plan.

[14] See pages 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 for a description of the three methods suggested in the plan.

[15] See page 107 in the 2021 Power Plan Section 9: Cost Effective Methodology for Providing Reserves

2. **No Resource Strategy (*No RS)***

The *No RS* scenario only includes the 590 megawatts of new renewables that have already been built since the 2021 Power Plan.

3. **Minimum Resource Strategy (Min RS)**

The *Min RS scenario* is like the *RS Ref* scenario, but includes the plan's minimum amounts of renewables (2,500 megawatts less) and energy efficiency (250 average megawatts less):

- 750 average megawatts of new energy efficiency measures
- 720 megawatts of new demand respond capabilities
- 2,910 megawatts of new renewables
- 590 megawatts of new renewables added to the existing resource mix
- 6,000 megawatts of total Incremental reserves

4. **Limited Markets (RS Ref)**

The limited markets scenario evaluates the regional power supply's adequacy with a more limited WECC buildout. Specifically, the planning reserve margins of each zone are removed, meaning that planning for adequacy is no longer the objective, and resources are built to meet renewable and clean air policies.

This is implemented by eliminating the operating pool planning reserve margins in the AURORA production-cost model while keeping all other conditions of the *RS Ref* case. Using post-processing analysis of the AURORA buildout, the WECC market capabilities and prices are extracted as inputs for GENESYS out-of-region market inputs.

While this sensitivity is important to evaluate, the plan's resource strategy recognizes the impact of limited markets and explicitly calls on the region to explore new market tools, such as capacity and reserve products, to improve system efficiency and increase reliability.

Staff believe the resource strategy addresses this risk. Additionally, staff believe the region is addressing this risk through its efforts to develop the Western Power Pool's Western Resource Adequacy Program (WRAP) and explore potential organized day-ahead markets.

5. **High WECC Demand (RS Ref, +200 aMW EE)**

The high WECC demand scenario uses the same resource strategy as the *RS Ref* but with an additional 200 average megawatts of energy efficiency, reaching 1,200 average megawatts. The scenario includes higher loads due to increased electrification, mainly in the Pacific Northwest, California, and the Canadian provinces of British Columbia and Alberta. All other inputs are the same as *RS Ref,* aside from updating renewable policy targets in megawatt-hours.

While the increased regional load forecast by 2045 is substantial, the average load increase by 2027 is 9.5 percent, based on the aggressive emission reduction scenario in the 2021 Power

Plan. Throughout the WECC, 2027 will see an average load increase of 1.5 percent, with WECC values updated in May of 2022. More work needs to be done to understand how that compares to actual expected load growth driven by new policies implemented since the adoption of the plan.

Plan analysis suggests that the level of renewables tested (5,410 megawatts) is well below what would be required in a world on a path to high electrification (plan analysis suggests closer to 15,000 megawatts would be required). However, staff believe that the 2021 Power Plan resource strategy and conservation program provides sufficient guidance on the types and amounts of new resources needed to address adequacy needs in a world of high WECC demand.

Staff will continue to track load growth, as well as resource builds, both in region and across the WECC to determine if the region and WECC are on a high demand path and will work to size the potential need for increased renewables and energy efficiency to ensure that adequacy is maintained.

6. <u>Persistent Global Instability (RS Ref)</u>

The persistent global instability scenario tests delayed deployment of WECC renewables and prolonged higher fuel prices. Since completing the plan, several global events have affected supply chains and increased natural gas prices, warranting further evaluation. Utilities have been planning for many of the resources identified in the plan, which may buffer somewhat the impacts of supply chains, but more tracking is needed. Staff agree that this is indeed a challenging scenario and one to monitor closely between now and the next adequacy assessment. For renewables in the rest of the WECC, the delay is implemented by reducing the maximum annual new additions of solar, wind, and short duration storage until 2030, with remaining resources unchanged due to online dates or previous restrictions. For fuel, the scenario evaluates natural gas prices that are 56 percent – 68 percent higher than the baseline prices following seasonal fluctuations.

7. <u>Early Coal Retirement (RS Ref)</u>

The early coal retirement scenario removes the Montana based Colstrip 3 and 4 coal plants from the 2027 assessment, which is earlier than their projected retirement dates, without the addition of replacement resources. All other parameters and conditions are the same as in the *RS Ref* scenario.

While not explicitly addressed in the plan resource strategy, the plan analysis demonstrated that additional resources would be needed if the WECC were to retire coal plants earlier than already slated. The plan analysis showed over 10,000 megawatts of renewable builds would be required to replace the power of early coal retirements. This need for new renewables is decreased to just under 8,000 megawatts when those coal resources are replaced by other thermal options. As in the high WECC demand scenario, staff will work to size the potential need for increased renewables and energy efficiency to ensure that adequacy is maintained if major resources are anticipated to be shut down earlier than expected.

8. No WECC Buildout (RS Ref)

The no WECC buildout scenario models the *RS Ref* conditions for the region, but only existing resources across the WECC. Council staff do not see this sensitivity as a likely future as there has already been an additional 25 gigawatts of resource developed across the WECC since the plan (note these 25 gigawatts of resources were included in this adequacy assessment). The fact that so many builds have occurred already, and other indications, show that the WECC is planning to build to meet planning reserve margins. But while the risk of a future with no additional WECC buildout seems low, it still warrants an evaluation. Staff will continue to monitor WECC-wide resource development on this.

9. Southwest Drought (RS Ref)

The Southwest drought scenario evaluates a future where four major hydroelectric projects are removed from California, Arizona, and Nevada due severely low reservoir elevations that eliminate their ability to generate. The projects include Glen Canyon, Hoover (spilt between Nevada and Arizona), Lake Oroville, and Lake Shasta. To implement severe drought conditions (eliminating hydroelectric generation from these projects), the generating capability of each project was removed from the hydro market price bin ($0) in their respective zones, representing an average total generating capability loss of 2,826 megawatts, as presented in Table 2.

Table 2. Hydro projects removed for SW Drought scenario

Project	Average Capacity Removed (MW)	Zone
Glen Canyon	923	Arizona
Hoover	730	Arizona
	316	Nevada South
Lake Oroville	542	North California
Lake Shasta	315 (was already at 50%)	North California

These dams were selected because of their historic drought conditions, recent operational changes (due to low reservoir levels), and forecasts of low-to-no generation probabilities by 2025 to 2027. Figure 2 shows the locations of the dams and associated balancing authority zones in California, Nevada, and Arizona. All other conditions are the same as in the baseline scenario.

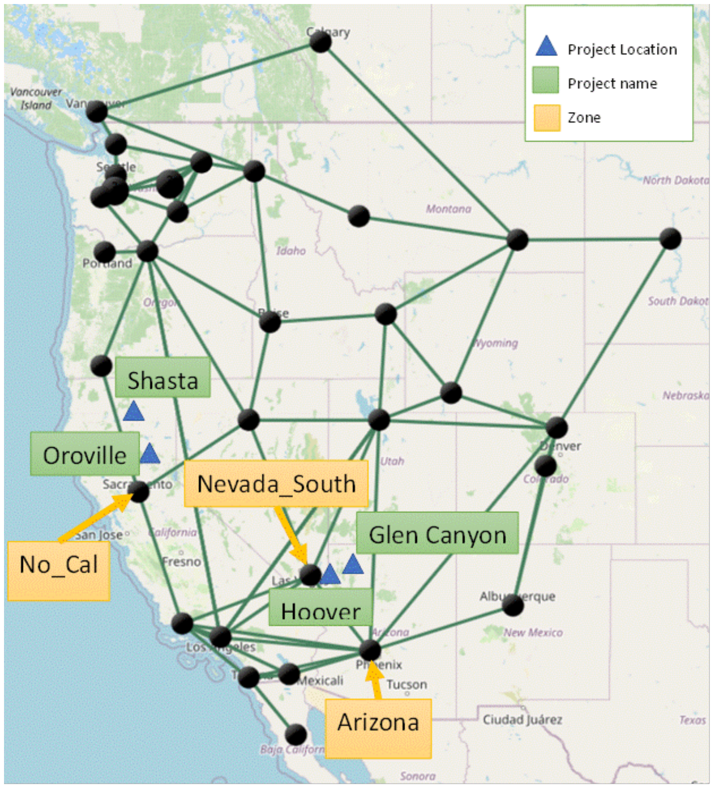

Figure 2. Map of SW Drought Scenario

10. <u>Pipeline Freeze (RS Ref)</u>

The pipeline freeze scenario evaluates the impact of losing 5,000 megawatts of natural gas supply from Arizona during the winter, from November until February. The loss was implemented by removing 5,000 megawatts of available capability from the Arizona natural gas price bins (i.e., the $30 and $40 price bins). All other conditions are to the same as in the baseline scenario.

11. <u>Wildfire (RS Ref)</u>

The wildfire scenario represents an initial attempt at evaluating the adequacy impact of a wildfire in the Pacific Northwest. Because the potential impact of wildfires includes transmission line shutoffs, this scenario implements a wildfire by derating specific bulk transmission lines. The chosen scenario represents a wildfire affecting three transmission paths connecting the balancing authority areas of Bonneville Power Administration Oregon, PacifiCorp West, Idaho Power, and Bonneville Power Administration Washington as illustrated in Figure 3. These lines were derated by 50 percent – 90 percent, during an entire July week (July 16 – 23). Generally, a transmission shut down due to a wildfire is not expected to last a week, but the current model does not have the capability to simulate shorter transmission derates.

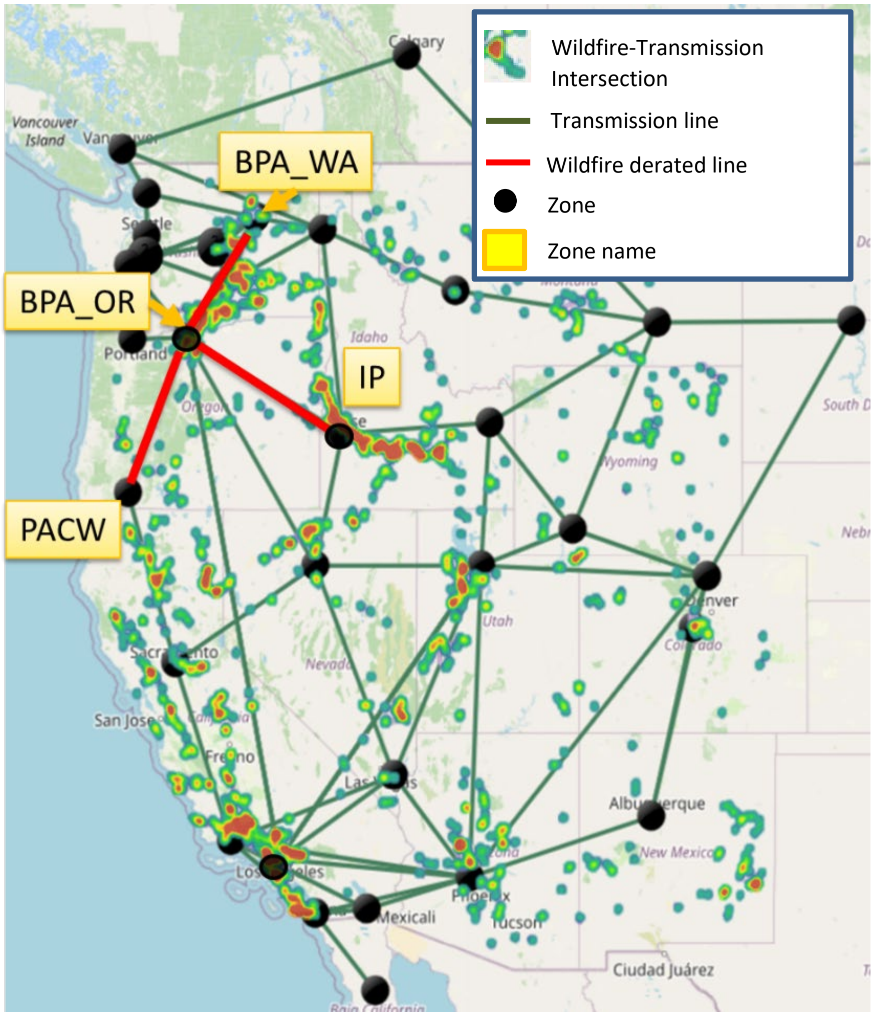

Figure 3. Map of Wildfire Scenario

These specific lines were selected for the wildfire scenario after analyzing historic intersections of wildfires with transmission lines from 1984-2020 and consulting with industry partners. Future wildfire modeling efforts will focus on stochastic transmission outages to evaluate different wildfire-outage profiles for different lines and time periods, both for within region and for out-of-region connections that could jeopardize import and export capability.

Adequacy Study Results

Under expected future conditions, the reference resource strategy delivers an adequate supply with an LOLP of less than 5 percent. While the minimum resource strategy also results in an adequate supply with an LOLP of less than 5 percent, the reference scenario greatly reduces the size of capacity and energy shortfalls for rare events (relative to the minimum resource strategy). This is significant because it affects the resiliency of the power supply; the impact of rare events is reduced.

Table 3 presents results relative to the current standard (5 percent LOLP) and to the proposed multi-metric standard for all scenarios that were analyzed. The table illustrates the significance of shifting to a multi-metric approach, as the five scenarios deemed adequate under the LOLP standard have varying degrees of differences, most notably in terms of tail-end risk to peak and energy demand. The scenarios deemed adequate from the LOLP standard are also considered adequate under the proposed multi-metric standard.

Considering scenarios that are not adequate under the LOLP standard sheds light on the value of a multi-metric approach. Though limited markets, global Instability, and no WECC buildout share a similar LOLP (7.8, 7.2, and 8.3) as well as borderline LOLEV, limited market has peak and energy values within the provisional range. Global instability and no WECC buildout are borderline. And while early coal retirement has a higher LOLP (13.9), it has peak and energy values that are acceptable.

Results suggest that all scenarios protect against long duration events, with the Duration $VaR_{97.5}$ values falling well below the 8–12-hour provisional limit. This finding does not imply that the duration metric is not important, but rather that it may either be (a) non-binding or (b) may need to be modified to test different duration risks.

The scenario that suggests the greatest risk to adequacy, aside from not implementing the resource strategy, is the high WECC demand, with all metrics exceeding the LOLP and provisional thresholds, aside from duration.

Table 3. Summary Adequacy Results

	Current Standard	Proposed Multi-Metric Standard			
Study	**LOLP**	**LOLEV**	**VaR Duration**	**VaR Peak**	**VaR Energy**
RS Ref	4.4	0.067	2	357	590
No RS	46.1	0.933	6	2922	12504
Min RS	4.4	0.061	2	837	1666
Limited Markets	7.8	0.144	2	1450	3147
High WECC Demand	17.2	0.589	5	4792	36617
Global Instability	7.2	0.144	3.5	2041	5969
Early Coal	13.9	0.233	2.5	1895	3807
No WECC Buildout	8.3	0.172	3.5	2015	6410
SW Drought	5	0.083	2	744	1421
Pipeline Freeze	5	0.072	1.5	505	710
Wildfire*	4.4	0.067	2	357	590

Acceptable
Borderline
Exceed

While the proposed metrics are emphasized in this adequacy assessment, it should be noted that adequacy during the 2021 Power Plan was evaluated according to the 5 percent LOLP standard only. The LOLP results for scenarios examined in this assessment are shown in Figure 4. Accordingly, the assessment provides a high level of confidence in reporting that the 2021 Power Plan resource strategy will result in an adequate power supply under baseline market/WECC conditions (resource strategy reference and minimum resource strategy), as well as under several WECC stress conditions (Southwest drought, pipeline freeze, and wildfire).

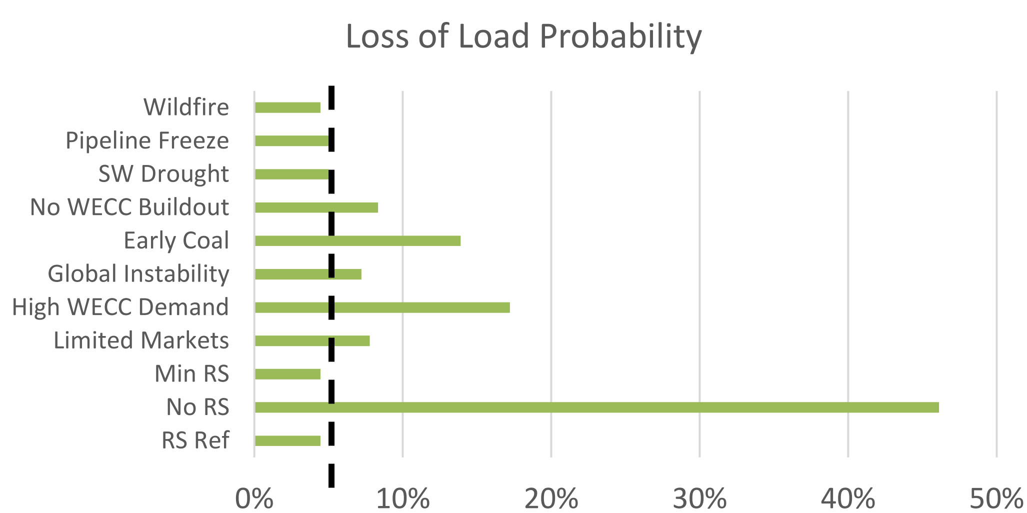

Figure 4. Loss of Load Probability

However, if future electricity market supply conditions are significantly limited, or if accelerated electrification policies result in rapid demand increase, or if major resources are retired earlier than expected, the baseline resource strategy is insufficient to maintain adequacy. This point is evident both from the perspective of LOLP and from the proposed set of new metrics. Under these market and electrification conditions, additional resources are needed, as detailed in the 2021 Plan analysis.

Protection Against Overly Frequent Use of Emergency Measures

The adequacy assessment finds three scenarios that exceed the LOLEV threshold, namely the no resource strategy, the high WECC demand, and the early coal retirement scenarios, with substantial violations of LOLEV for the first two. Of the remaining scenarios, the no WECC buildout, global instability, and limited markets are deemed borderline as they fall within the provisional range, as seen in Figure 5. These borderline scenarios illustrate the importance of appropriately setting metric thresholds, because a higher limit tolerance (in this case 0.2 events/year) would deem these borderline scenarios adequate, whereas the lower limit tolerance would deem them inadequate.

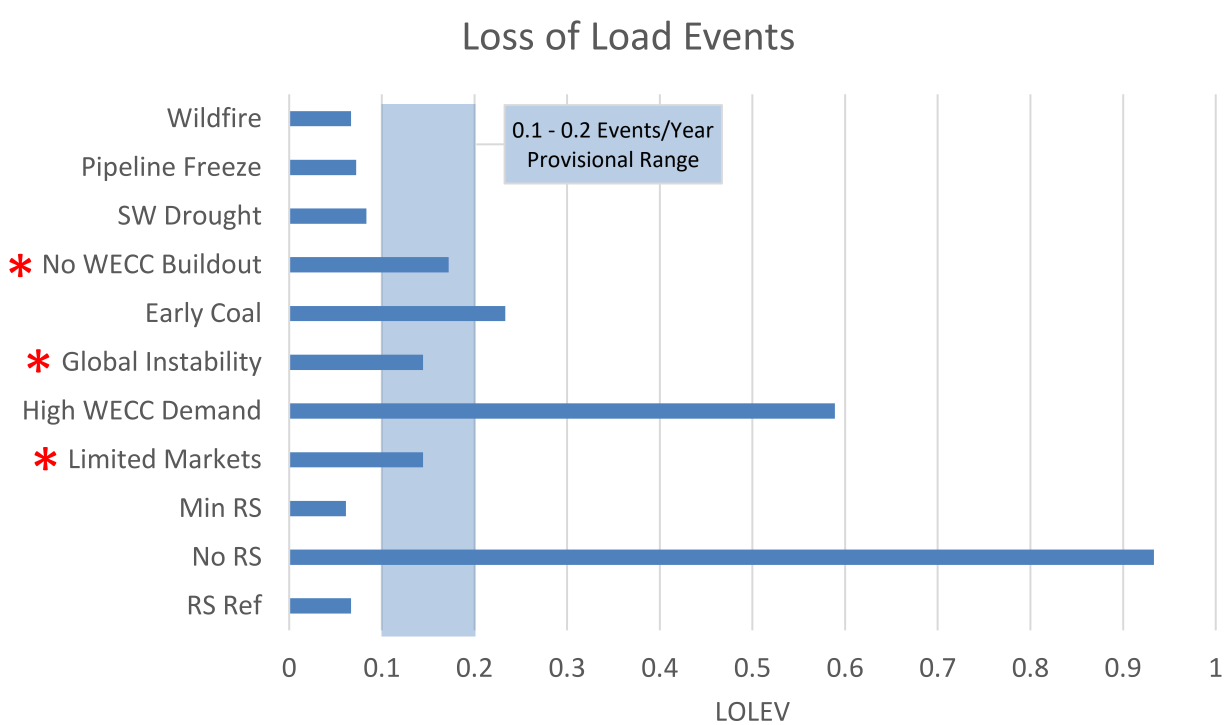

Figure 5. Loss of Load Events metric

Limit Occurrences of Long Duration Events

Current analysis shows that all scenarios protect against long shortfall durations, as the Duration $VaR_{97.5}$ values are all below 8 hours. Most scenarios hover around 2 hours, with the higher stress scenarios reaching 3, 4, and 5 hours, as shown in Figure 6. In fact, all but the high WECC demand scenarios have maximum shortfalls below the 8-hour lower bound, meaning all observed shortfalls are below the threshold.

Given that all scenarios are adequate from the duration perspective, it could signal that such a metric is either non-binding or that it could be modified to test the risk tolerance for different event durations. For example, if the duration thresholds were 3 to 4 hours, then the no WECC buildout, global instability, high WECC demand, and no resource strategy scenarios would be deemed inadequate.

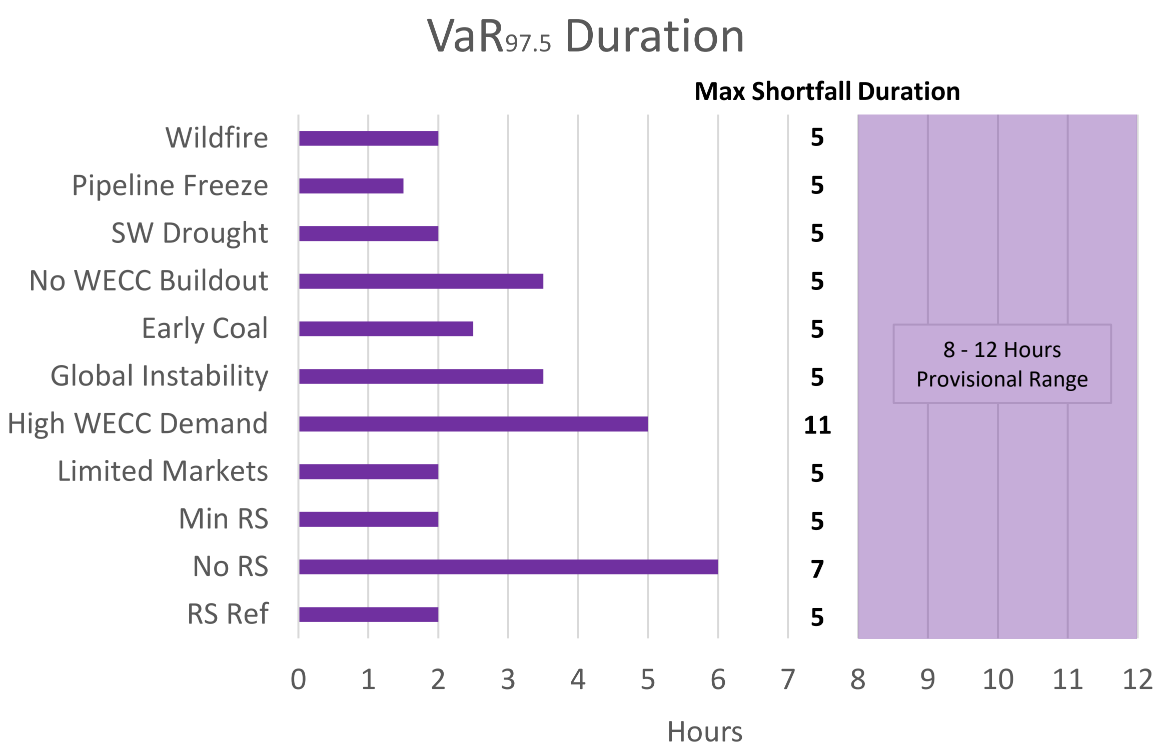

Figure 6. VaR 97.5% Duration Metric

Limit Occurrences of Big Capacity Shortfalls

The peak shortfall capacity metric shows greater variability across the scenarios, with the baseline and WECC stress scenarios well below the provisional 2,000-to-3,000-megawatt range. The only scenario to exceed the threshold is the high WECC demand at 4,792 megawatts at the 97.5 percent percentile. However, the no WECC buildout, global instability and no resource strategy scenarios are borderline, with the former two slightly above the minimum as seen in Figure 7. The early coal scenario is just below the lower end of the provisional limit at 1,895 megawatts.

In terms of maximum observed capacity shortfalls, most scenarios fall between 3,200 - 4,200 megawatts, with high WECC demand surpassing 6,000 megawatts. However, as with the duration metric, these events are expected to occur once every 180 years and are therefore not planned for mitigation. For the scenarios deemed peak capacity adequate, the difference in tail-end values signals the possible acceptable magnitude of each scenario's impact to the system.

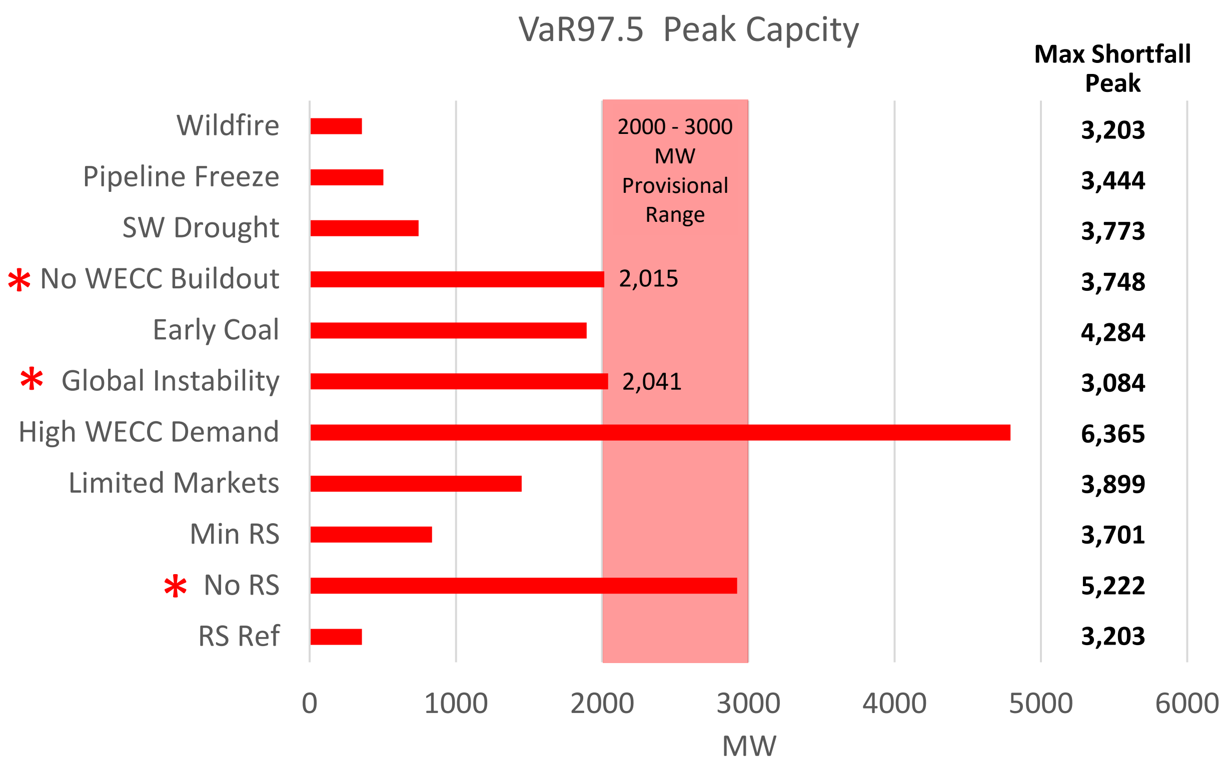

Figure 7. VaR 97.5 Peak Capacity Shortfall

Limit Occurrences of Big Energy Shortfalls

From an energy perspective, there are two scenarios exceeding the adequacy threshold: high WECC demand and no resource strategy. As visualized in Figure 8, the high WECC demand scenario demonstrates a substantial violation of the metric, over four times the upper end of the 8,000 megawatts provisional range. The no WECC buildout and global instability scenarios offer borderline adequacy protection, both around 6,000 megawatt-hours, the midpoint of the provisional range.

The remaining scenarios are deemed energy adequate, with early coal retirement just below the provisional limit, at 3,807 megawatt-hours. However, though these scenarios are adequate, the variation in tail-end values illustrated the risk impact of each to the overall region.

Considering the maximum energy shortfall, the benefit of utilizing a tail-end metric is further highlighted. Unlike the previous metrics, many of maximum values are significantly higher than the provisional range, signaling the significance of setting a limit based on emergency resources that accounts for 97.5 percent of possible shortfall values.

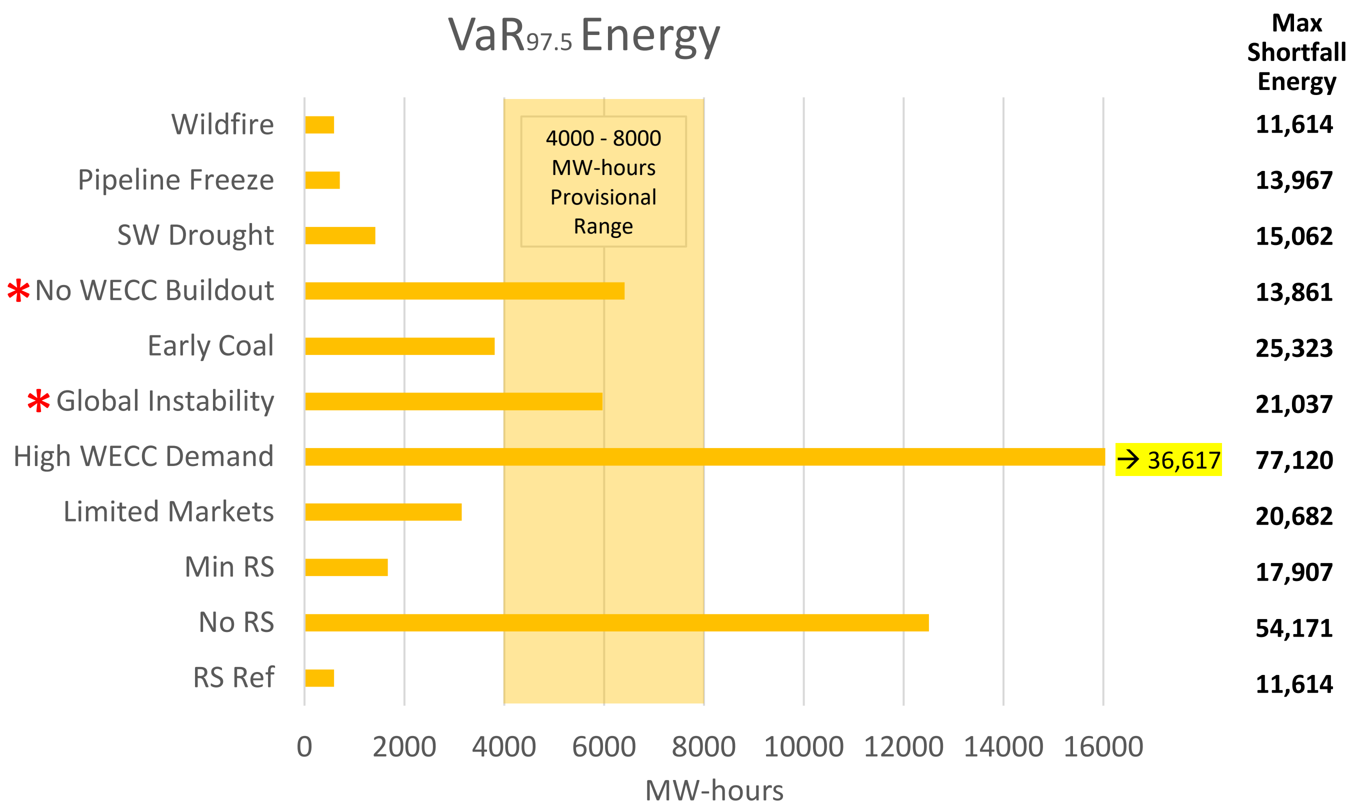

Figure 8. VaR 97.5 Energy Shortfall

Impact of Reference Resource Strategy and Minimum Resource Strategy

The reference strategy has an additional 2,500 megawatts of renewables and 250 average megawatts of energy efficiency above the minimum resource strategy. While both offer similar adequacy benefits in terms of LOLP, protection against frequent use of emergency resources and limiting long duration events, they differ in terms of peak capacity and energy shortfalls. Both are still considered adequate, but the reference scenario further reduces the peak capacity shortfall by 480 megawatts and energy shortfall of 1,076 megawatt-hours over the minimum interpretation.

Both scenarios mitigate summer shortfalls associated with the no-new-resource scenario, but neither eliminates winter shortfalls. As observed in Figure 9, the monthly expected unserved energy (EUE), a measure of the average magnitude (not tail-end magnitude) of energy demand not served, demonstrates the contribution of the reference resource strategy in reducing average loss of service over the minimum resource strategy.

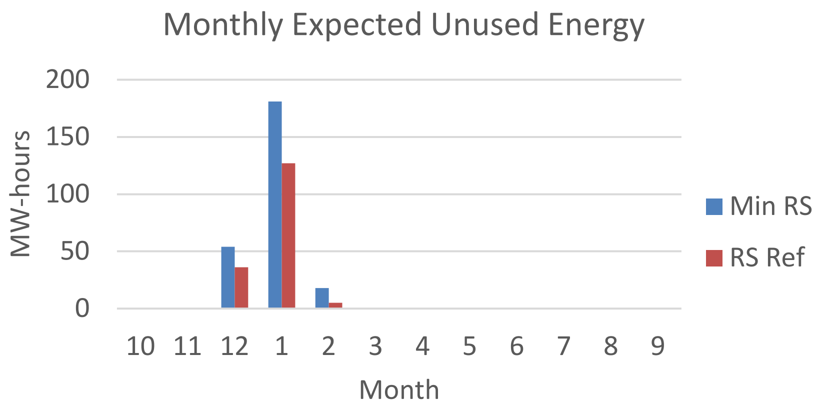

Figure 9. Monthly EUE of reference (RS Ref) and minimum resource strategy (Min RS)

While both the reference and the minimum strategies are considered adequate across the metrics, these differences can be significant, especially when considering the ramp hours. The remaining shortfalls, aside from one, occur mostly during the morning ramp between 6:00 a.m. - 11:00 a.m. and the evening ramp of 5:00 p.m. - 7:00 p.m. Figure 10 demonstrates the heatmap of the maximum capacity shortfalls by monthly hours. The blank space indicates no shortfalls were recorded, which is why most of the heatmap is white, aside from the ramp hours in winter. Generally, the reference resource strategy scenario reduces the maximum shortfall by 400 - 800 megawatts over the minimum strategy.

	Reference with Resource Strategy (*RS Ref*)																							
Month / Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1						1300	3203	2856	1915	792														
2							402	443																
3																								
4																								
5																								
6																								
7													9											
8																								
9																								
10																								
11																								
12							173										1942	2160						

	Reference with Minimum Resource Strategy (*Min RS*)																							
Month / Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1						1787	3701	3297	2439	1596														
2						298	896	856																
3																								
4																								
5																								
6																								
7																								
8																								
9																								
10																								
11																								
12							730										2706	2858						

Figure 10. Heatmap of Maximum Capacity Shortfall by Month-Hour
Top: Reference resource strategy. Bottom: Minimum resource strategy

Figure 11 further illustrates the impact of the reference resource strategy on the region in mitigating summer shortfalls and the magnitude of winter shortfalls if no strategy is implemented.

	Reference with Resource Strategy (*RS Ref*)																						
Month / Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1						1300	3203	2856	1915	792														
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7													9											
8																								
9																								
10																								
11																								
12							173										1942	2160						

	Reference Without Resource Strategy (*No RS*)																						
Month / Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1						3149	5222	4964	4398	3699	496													
2					334	2560	3010	3357	2011	1844														
3																								
4																								
5																								
6									676	1780	1154		248	1189	1526	1174	979	1089	587	29				
7												625	285	384	749	370	398	355						
8														303	767	1153	888	697						
9																								
10																								
11							782	780	94															
12							746	191	467							1323	4275	4496	1732					

Figure 11. Heatmap of Maximum Capacity Shortfall by Month-Hour
Top: Reference resource strategy. Bottom: No resource strategy. Boxes highlight summer (red) and winter (blue) shortfalls.

The reference strategy mitigates summer challenges across all scenarios as seen in Figure 12, and remaining shortfalls are almost entirely winter problems. Most of the scenarios have similar EUE values, aside from the high WECC demand and no resource strategy in January. This is consistent with the findings of the VaR 97.5 percent energy metric and observed variation across the scenarios, which does not offer seasonal perspectives.

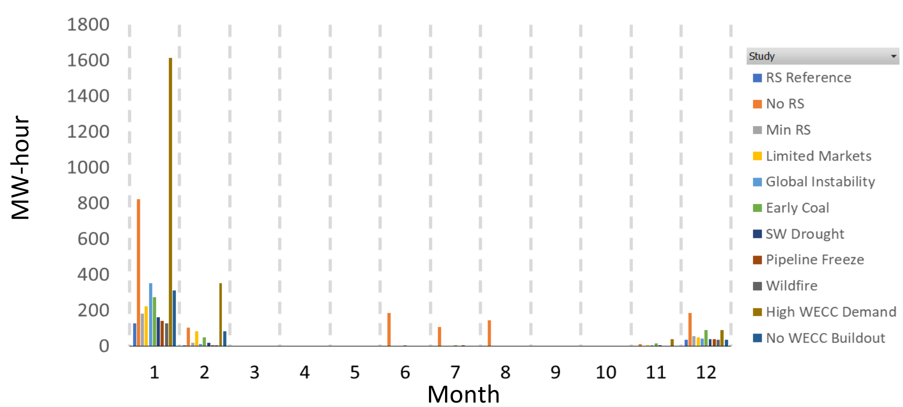

Figure 12. Monthly Expected Unserved Energy (EUE)

High Level Market Observations

The size of the WECC buildout can have substantial impacts on import/export behavior between the Pacific Northwest and the rest of the WECC, especially California, British Columbia, and Alberta. In California, scenarios with similar WECC buildouts had minimal impact to the import/export dynamics in comparison to the reference case, including min resource strategy, early coal retirement, pipeline freeze, wildfire, and Southwest drought. However, the import/export levels in the minimal/no buildout scenarios, limited markets and no WECC buildout, and high WECC demand scenarios had the biggest changes from the reference case. The import/export behavior under persistent global instability is more aligned with the reference scenario, having a similar buildout but with delayed renewable deployment. All import/export comparisons discussed in this section are in relation to the reference scenario, unless mentioned otherwise.

Considering that remaining shortfalls are mostly during winter ramp hours (except for high WECC demand, which may result in January shortfalls during 12:00 a.m. – 12:00 p.m. and 5:00 p.m. – 11:00 p.m.), it is valuable to observe the market dynamics during the morning and evening ramps in winter (December – February) and summer (July – September). The ratio of import/export hours over a time period may suggest the level of current market utilization and how each scenario responds to market conditions. As expected, different import/export dynamics are observed during the ramp hours, with the limited/no buildout scenarios showing less import during these hours.

For example, as seen in Figure 13, the reference resource strategy imports 67 percent of the time during the summer morning (6:00 a.m. – 10:00 a.m.) ramp, and 34 percent during evening (6:00 p.m. – 10:00 p.m.) ramp. However, under the limited markets and high WECC demand scenarios, summer morning imports fall to 28 percent of the time, and evening imports are all but eliminated. The substantial decrease in evening imports is due to lack of available market supplies, either from reduced capacity in the WECC (limited markets), or greater utilization of renewable resources to meet increased demand (high WECC demand) that minimize renewable curtailments. This helps explain why there are no imports during the ramp hours, both in winter and summer under the no WECC buildout scenario. The persistent global instability scenario suggests a different market response, having similar morning ramp imports in summer, but substantially lower evening imports (in the summer, 9 percent) than reference resource strategy.

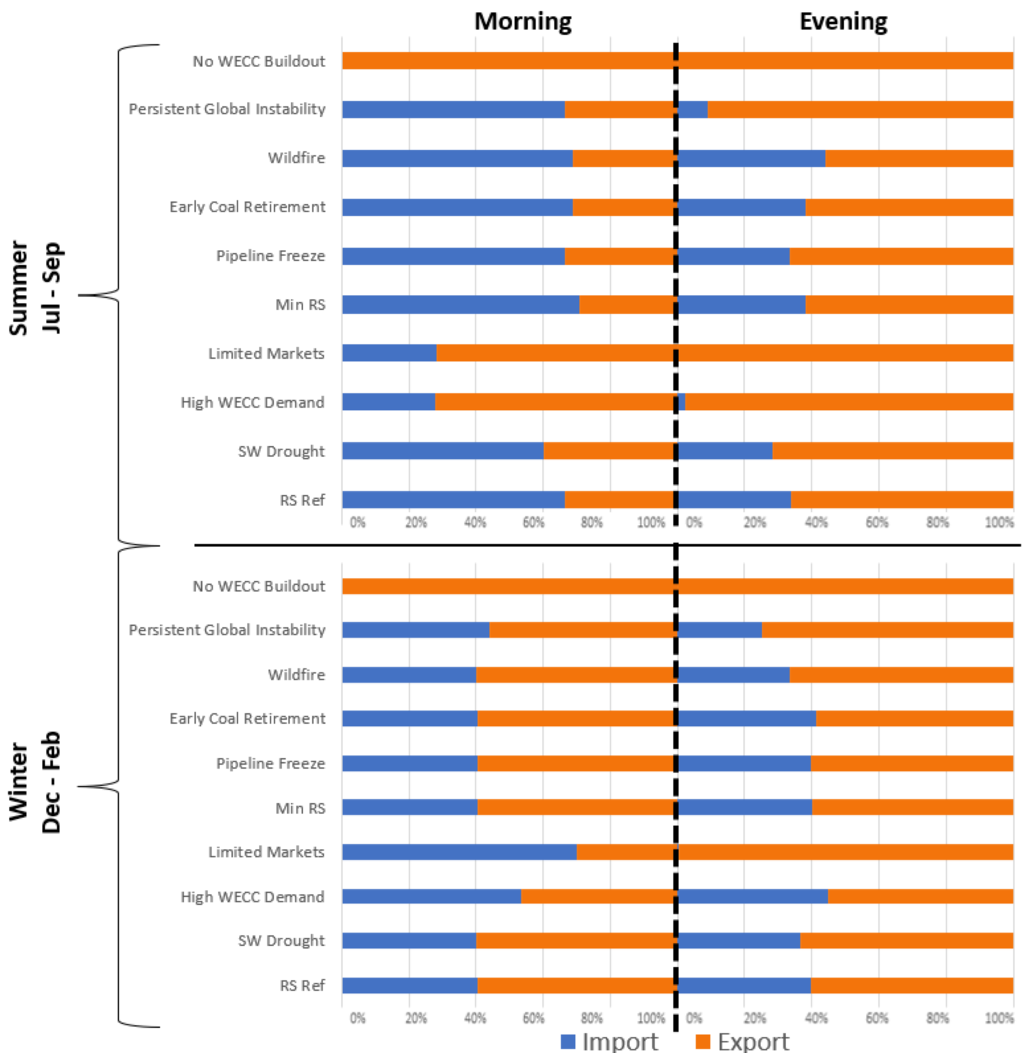

Figure 13. Seasonal Import/Export Dynamics during Ramp Hours

During winter, the morning ramp period has increased imports under limited markets and high WECC demand, with no imports under the no WECC buildout. This is likely caused by WECC resource expansion strategies that are designed to mitigate summer peak need challenges. Since most of the WECC is not dual peaking, the summer peak need is higher than the winter peak need, so many regions will have surplus winter generation available. However, in the evening ramp in the limited markets scenario, the Pacific Northwest only exports. This finding is not surprising, since often the time of greatest need in the WECC is the summer evening ramp period. Reduced reserve margins in the WECC would severely decrease excess generation during the evening ramp and cause other regions to rely more heavily on the Northwest system.

In terms of market reliance, the current net import limit assumption in the model is 2,500 megawatts in winter and 1,250 megawatts in summer. This level of reliance seems to mitigate the potential market fundamental risks of different WECC buildouts, relying more on in-region resources. Evidence for this lies in the fact that Southwest drought, pipeline freeze, and wildfire are adequate across all metrics, with varying degrees of adequate or borderline metrics under limited markets, persistent global instability, early coal, and no WECC buildout scenarios.

However, analysis suggests transmission limitations may have a larger influence on market dynamics. For example, on the one hand, the year-round imports from California appear to consistently reach the transmission limit of the AC and DC lines connecting California to the Northwest under the reference and persistent global instability scenarios. On the other, imports can be below (high WECC demand) or significantly below (limited markets and no WECC buildout) transmission limits in other scenarios.

Keep in mind that imports from California also include imports destined to go to Canada, the main reason why transmission limits are reached, as the Northwest market reliance limit alone is less than the transmission limitation. Traditionally, Canada imports and exports through the Northwest mostly in the winter, with 30 percent – 50 percent of the California midday solar surplus going to British Columbia.

Conversely, Canadian exports to the region during the morning ramp account for 20 percent – 50 percent of transmission flow through the region to California. Throughout the year, Canada imports primarily from the Northwest during the spring and winter evenings, and exports during winter morning ramps. Though a net Northwest importer, Canada uses its hydro system to provide targeted imports during higher priced ramping periods. In fact, the projected WECC buildouts are similar in almost all the scenarios, with buildouts only in Alberta.

Projected Impact on California Prices

Changes in import/export dynamics may also be driven by financial considerations, as the market price under different WECC buildouts would directly influence market decisions of when to purchase more expensive resources. As illustrated in Figure 14, analysis of monthly California electricity price distributions suggests limited markets and no WECC buildout have higher prices, in addition to the reduction or elimination of negative pricing due to lack of large renewables. The high WECC demand scenario also suggests higher prices with additional demand soaking up renewable surplus during midday hours. Under the conditions of persistent global instability, hourly prices generally appear to follow a similar pattern as in the reference scenario.

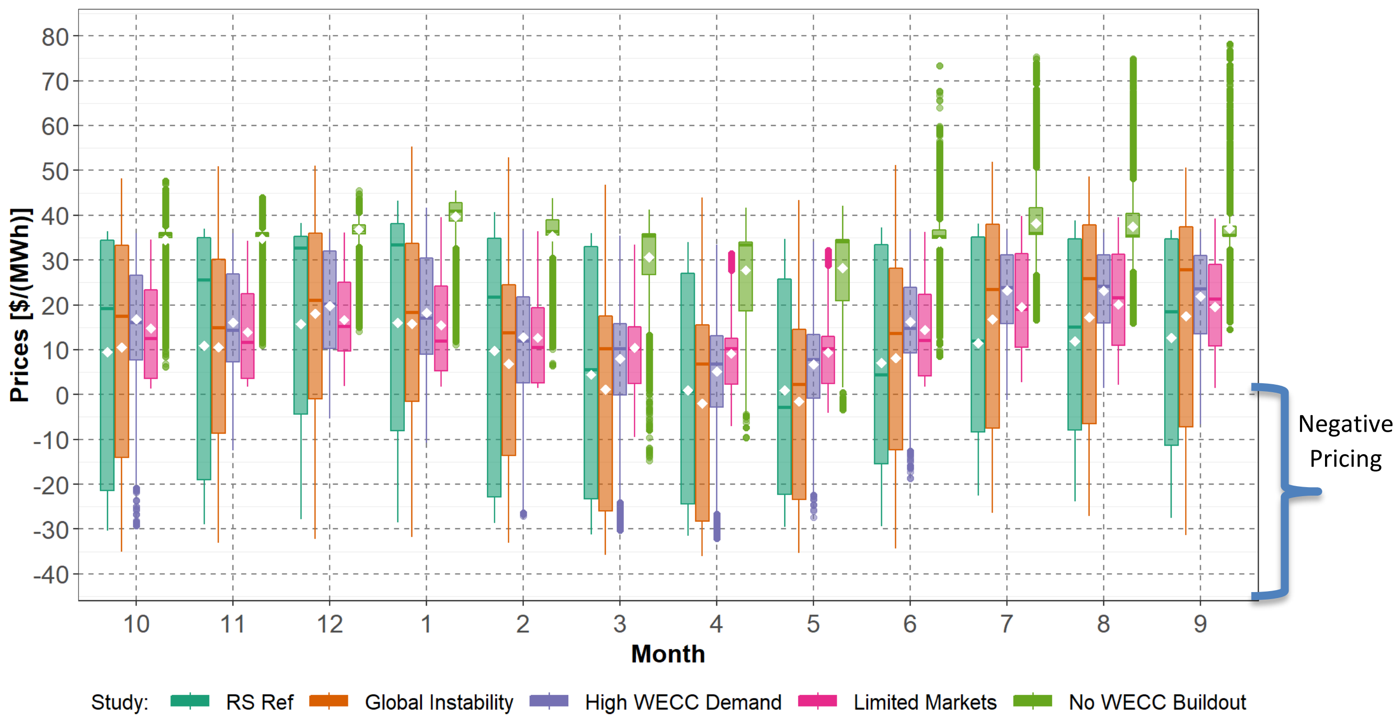

Figure 14. Projected California Monthly Electricity Prices

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