Pacific Northwest Power Supply Adequacy Assessment for 2029

Northwest Power and Conservation Council

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2029 Adequacy Assessment

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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.

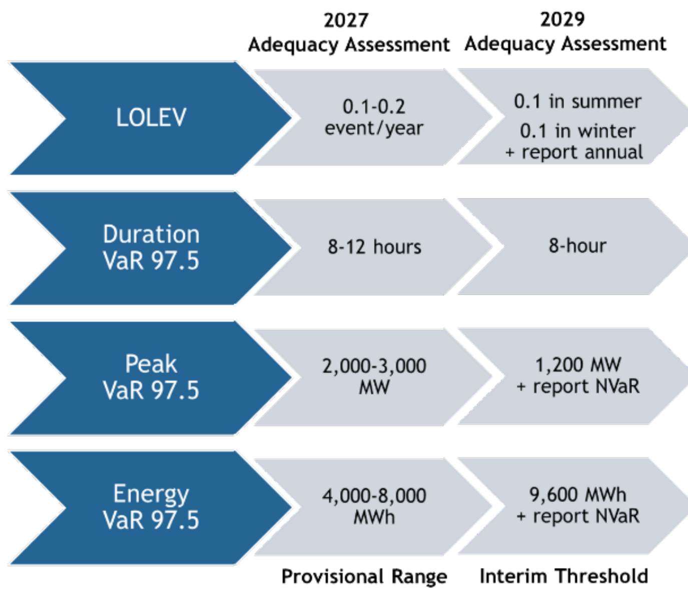

Figure 1. Evolution of metric thresholds

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.

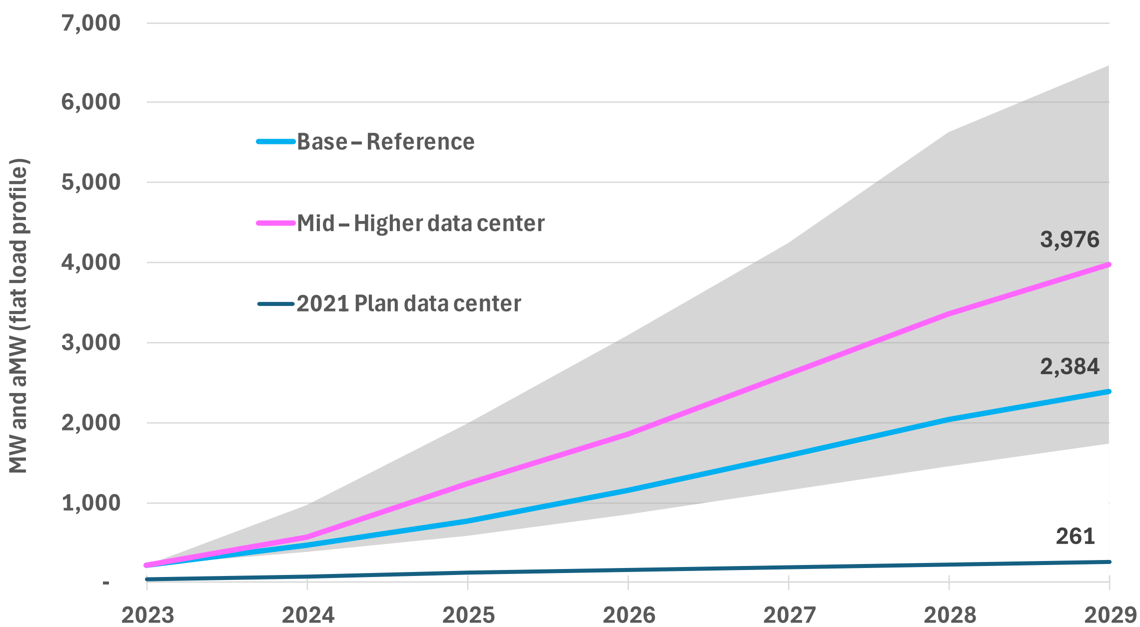

Figure 2. Incremental data center and fab growth forecast, 2023 to 2029

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.

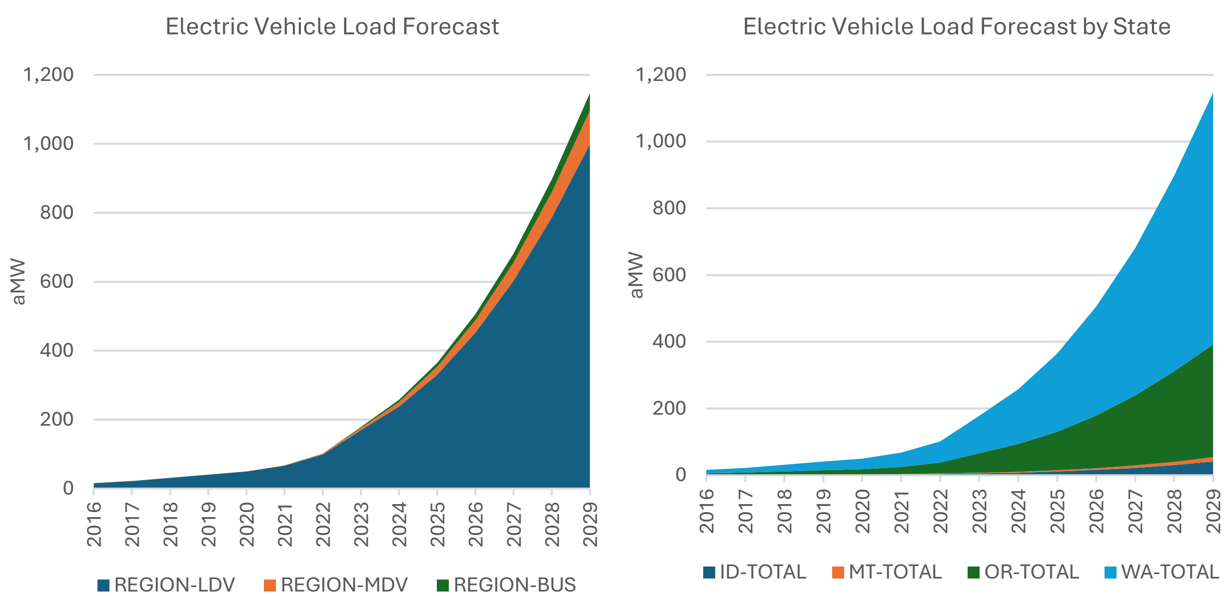

Figure 3. Electric vehicle load forecast by region and state

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*	–

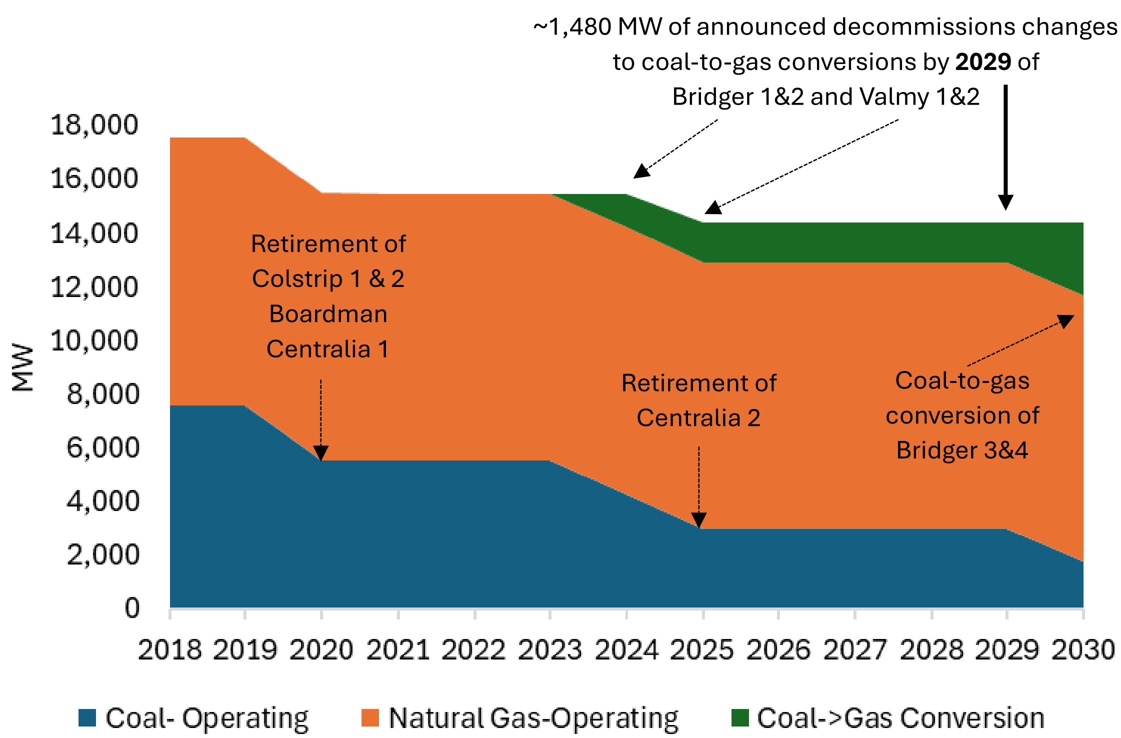

Figure 4. Cumulative thermal capacity changes in the region

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.

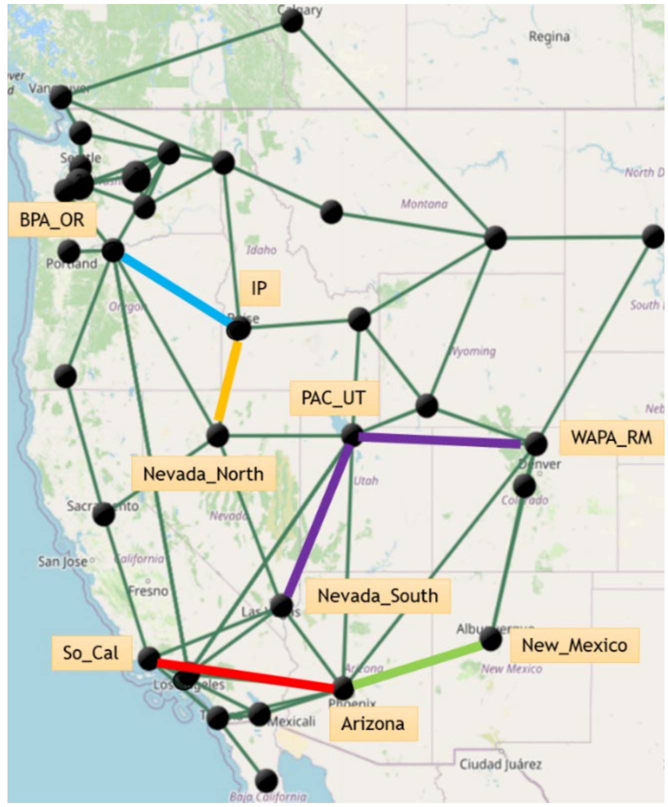

Figure 5. Transmission expansions in 2029 Assessment

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.

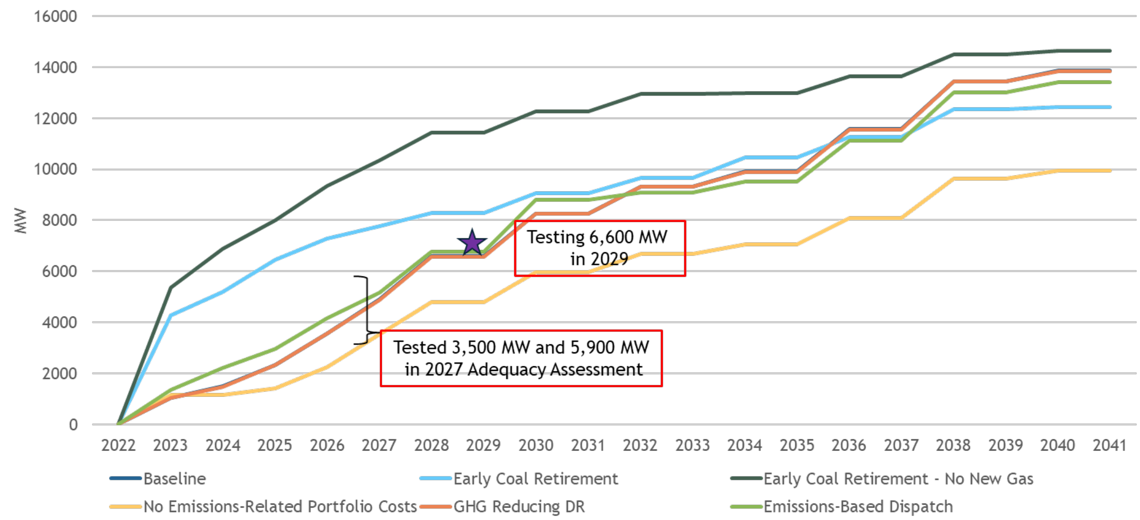

Figure 7. Example of renewable buildout trajectories from the 2021 Power Plan Resource Strategy

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.

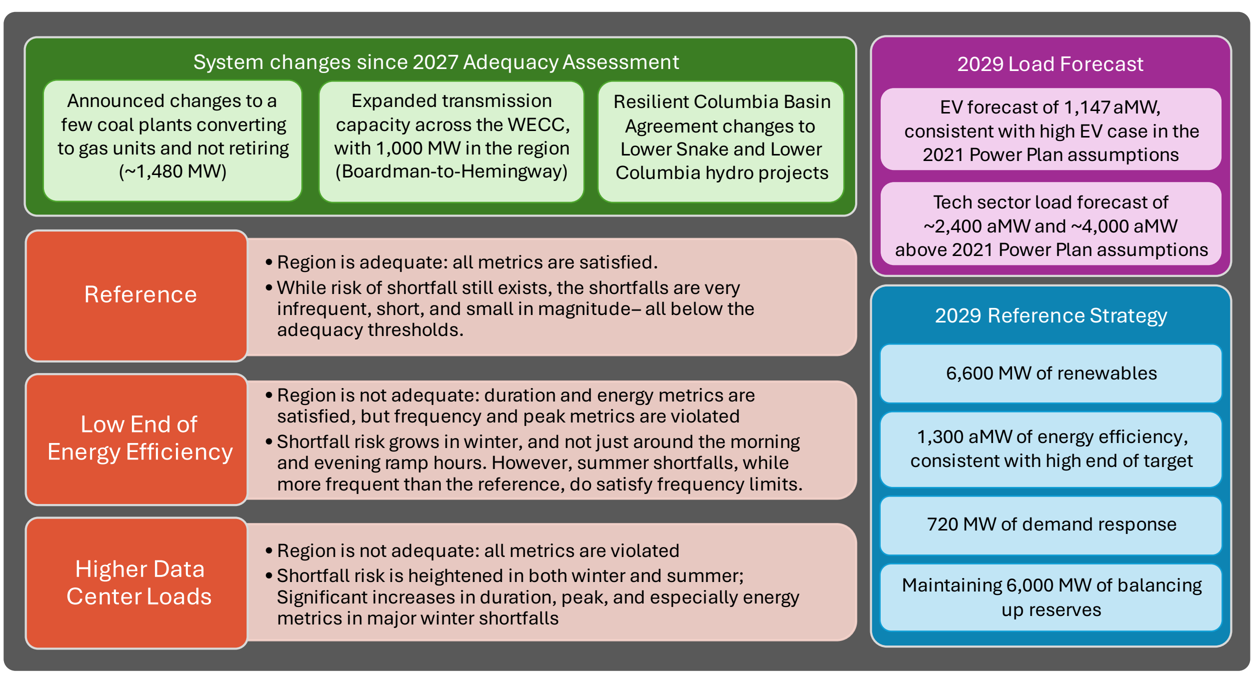

Figure 8. High-level summary of 2029 Adequacy Assessment

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.

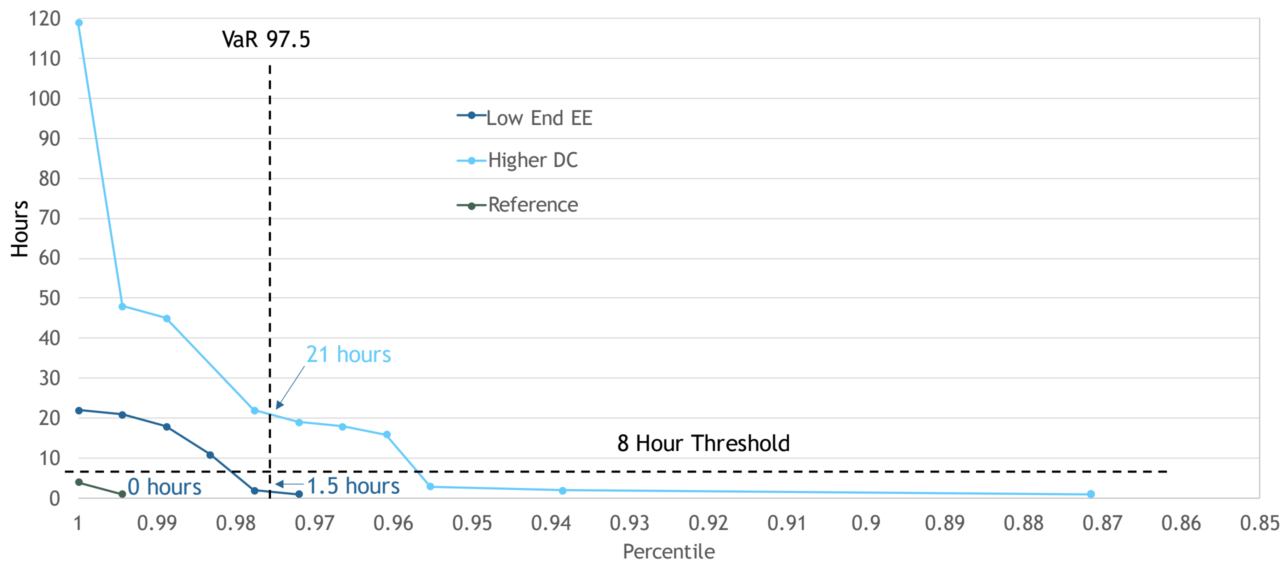

Figure 9. Max duration curves across the scenarios

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.

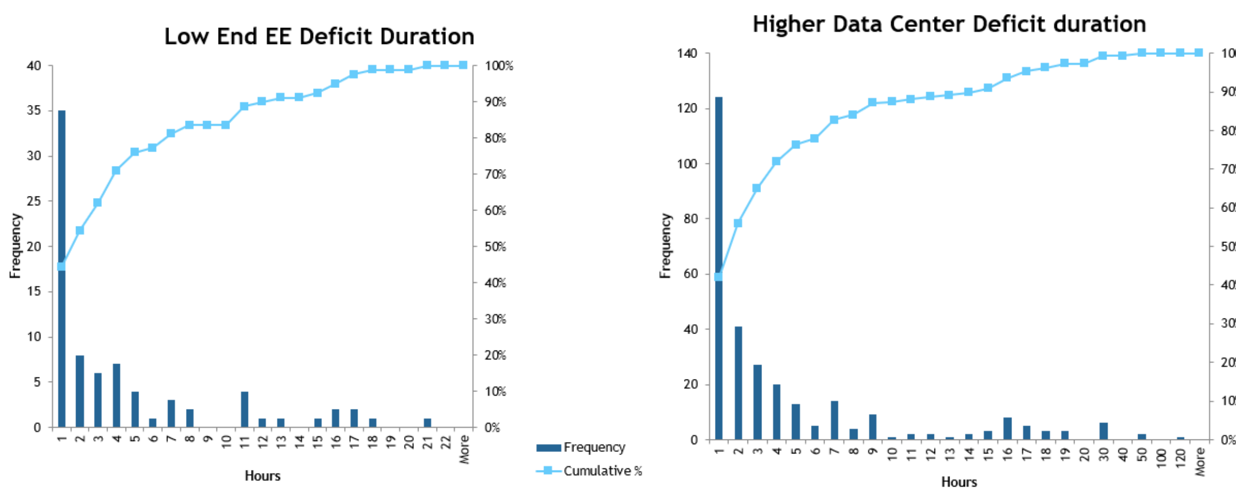

Figure 10. Distribution of shortfall durations in Low End EE and Higher Data Center scenarios

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.

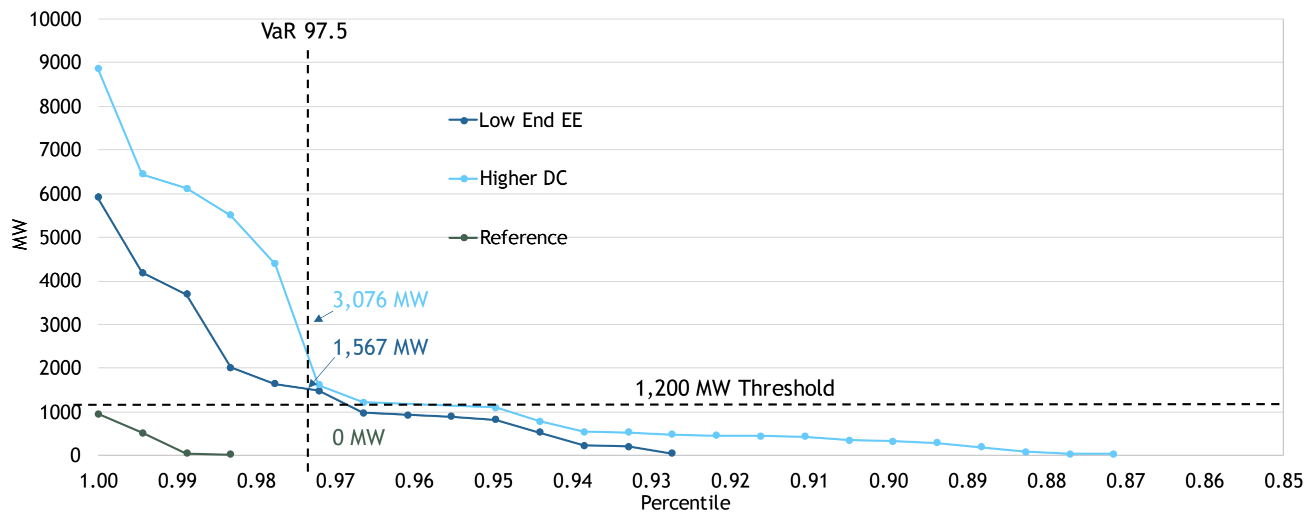

Figure 11. Max peak curves across the scenarios

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.

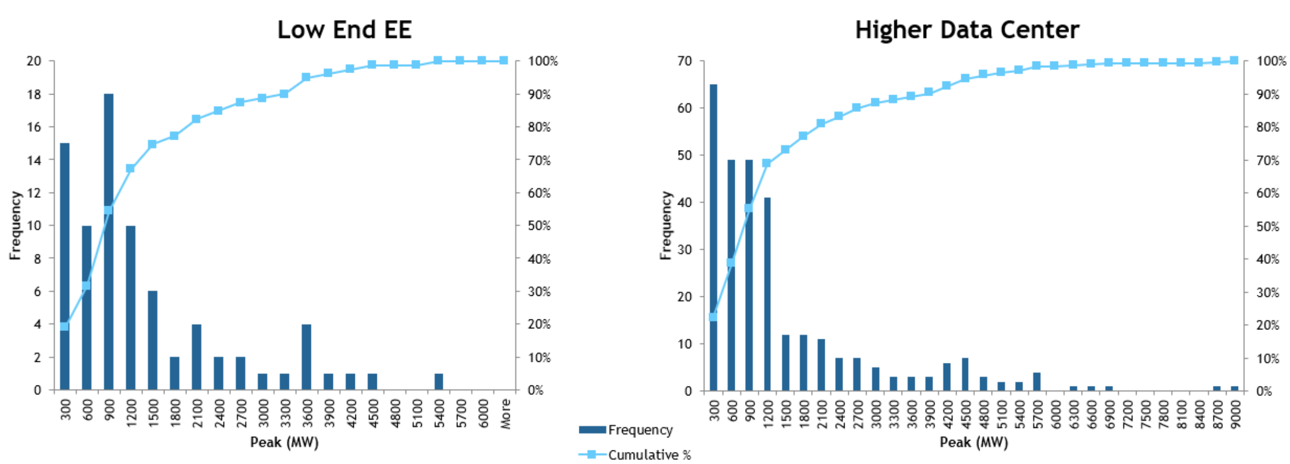

Figure 12. Distribution of shortfall peaks in Low End EE and Higher Data Center scenarios

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.

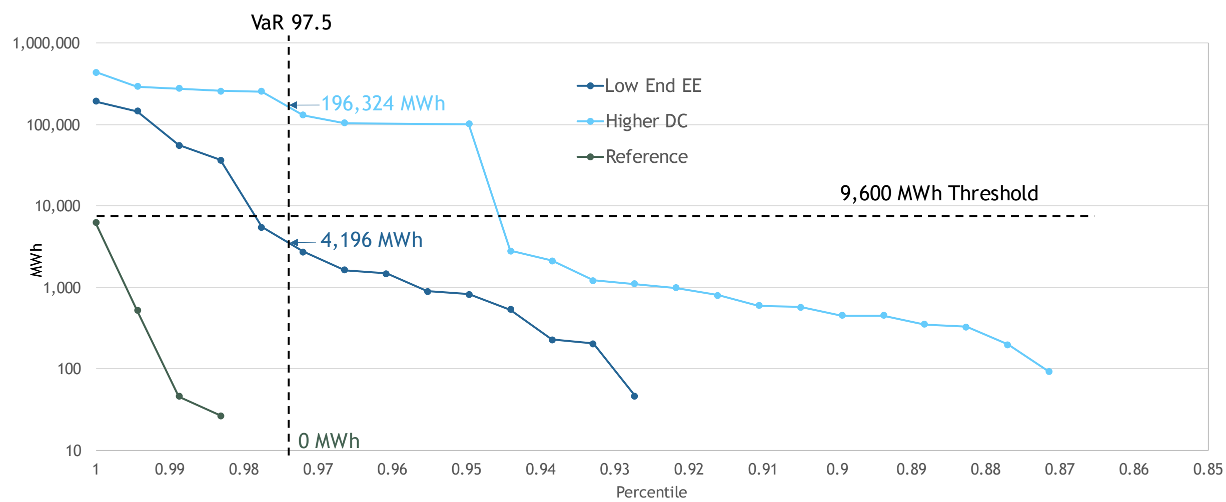

Figure 13. Annual energy curves across the scenarios

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.

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan																					689	844	960	924
Feb																								
Mar																							46	
Apr																								
May																								359
Jun																								
Jul																			27					525
Aug																								
Sep																								
Oct																								
Nov																								
Dec																								

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

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan		219			620	1394	2524	3855	5346	4414	3431	1220	336	450	768	521	1491	2785	2767	2972	542			413
Feb	726	658	618	612	652	730	1147	3694	1606	835	1223	1026	262	461	936	1200	1643	2162	2681	3455	2798	1259	1714	3511
Mar																								
Apr																							894	609
May						1159		224	347	98						2020	817							1489
Jun																							1426	825
Jul																								230
Aug																				576	635			975
Sep																						533		504
Oct																								
Nov																								
Dec	1184	1571	693	743	1560	2327	3203	4179	5328	5915	3383	3136	2461	2060	2241	2225	1972	3694	5100	4208	3549	2433	67	

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

Month / Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan	925	900	876	871	894	1146	3986	6117	5586	3963	3684	1726	1558	1431	1433	1326	2121	1910	2759	3043	1501	1022	981	1621
Feb	1144	653	613	607	647	1094	3062	5684	5138	4762	3648	1059	1059	947	888	1303	803	1856	1790	2433	1346			
Mar																		45						1217
Apr														38.439										
May																							69	199
Jun													978			193		550	551	533		208	141	
Jul																				34			368	1026
Aug														278	623	616	1479	1978	1865	1981	1820	539	1277	1680
Sep																								788
Oct																								
Nov																								
Dec	3999	1527	685	697	724	1541	3213	8090	8863	8407	7561	5121	3306	2700	4068	4414	6688	6440	5563	4829	3521	2547	1404	

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.