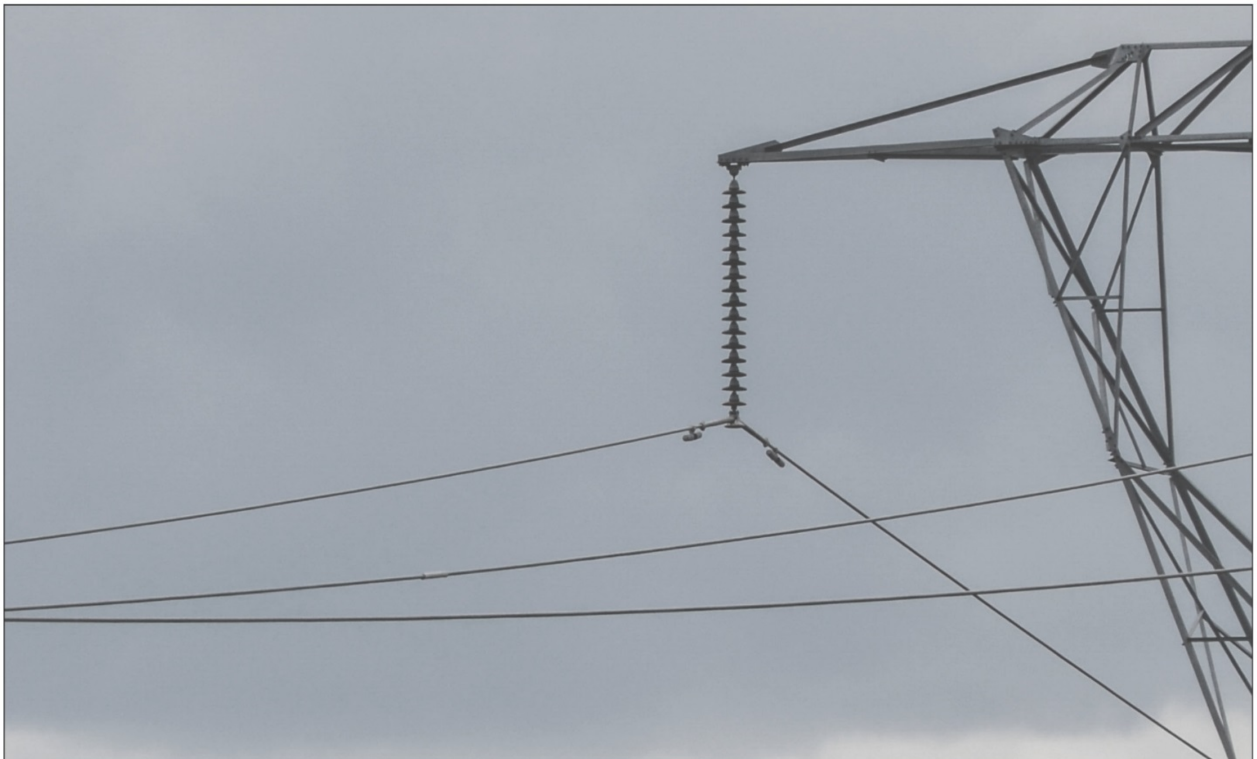
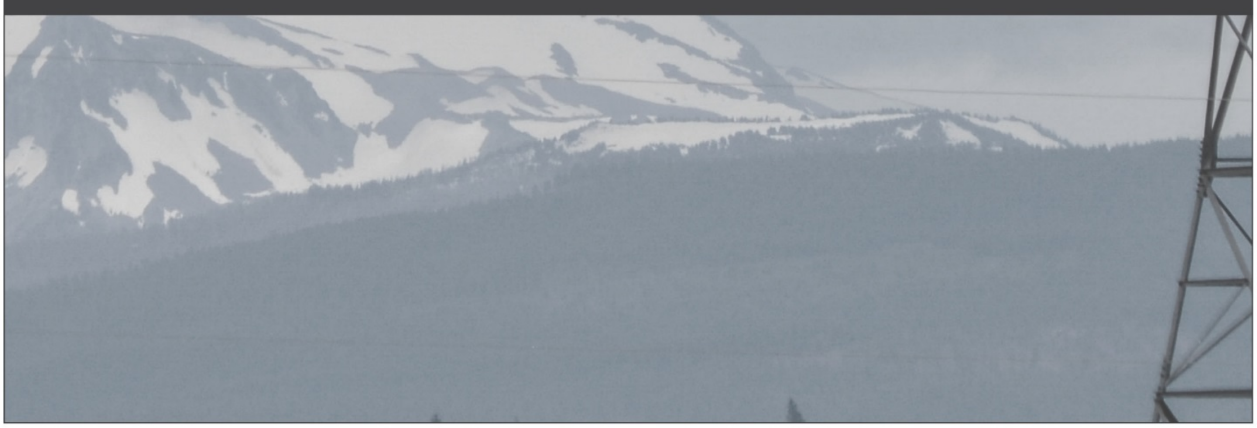


Pacific Northwest Power Supply Adequacy Assessment for **2023**



June 14, 2018
Document 2018-7

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

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FORWARD

This document summarizes the Northwest Power and Conservation Council’s assessment of the adequacy of the power supply for the 2023 operating year (October 2022 through September 2023). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for power supply adequacy and set its maximum value at 5 percent. For a power supply to be deemed adequate, the likelihood (LOLP) of a shortfall (not necessarily an outage) occurring anytime in the year being examined cannot exceed 5 percent.

The Council, with help of the Resource Adequacy Advisory Committee (RAAC), updated its resource and load data, examined all appropriate operating assumptions and ran the GENESYS model to produce the results shown in the charts and tables in this report. Other adequacy metrics that measure the size of potential shortages, how often they occur and how long they last are also reported because they provide valuable information to planners as they consider resource expansion strategies.

The Council is currently in the process of enhancing its adequacy model (GENESYS), in particular the hourly hydroelectric system dispatch simulation, and expects to complete the work by September of 2018. In addition, the Council has initiated a process to review its current adequacy standard. Council staff and RAAC members will be asked to review the viability of the current metric (LOLP) and threshold (5 percent). This review should consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).

EXECUTIVE SUMMARY

Accounting for existing resources, planned resources that are sited and licensed, and the implementation of the Council's energy efficiency targets, the Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 megawatts combined). The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the Council's standard of 5 percent.

By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants and the Pasco gas-fired plant (479 megawatts combined). In 2023 the LOLP is expected to remain at about 7 percent. The increase in LOLP would be higher except for the Council's targeted energy efficiency savings and savings from codes and federal standards. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 megawatts in 2021 with an additional need for 300 to 400 megawatts in 2022.

It should be noted that this analysis examines the adequacy of the aggregate regional power supply. Individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources. In aggregate, Northwest utilities have identified 540 megawatts of wind, about 800 megawatts of (unspecified fuel source) capacity and other small resources that could be developed by 2021, if needed.[1] These planned resources are not included in this assessment because they are not sited and licensed. Also excluded from this analysis are approximately 400 megawatts of demand response, which is the remaining part of the 600 megawatts identified in the Council's Seventh Power Plan as likely being available by 2021. While the Council believes this level of demand response will be available, it is not included in this analysis because of ongoing concerns regarding barriers to its acquisition.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent[2] results in an LOLP of just under 5 percent and has roughly the same effect as adding 650 megawatts of capacity. Increasing the load forecast by 2 percent[3] raises the 2023 LOLP to about 10 percent and almost doubles the amount of capacity needed (from 650 to 1,000 megawatts) to satisfy the Council's 5 percent standard.

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[1] Source: Pacific Northwest Utilities Conference Committee's 2018 Northwest Regional Forecast.

[2] This means multiplying the load in each hour of the year by 0.98.

[3] This means multiplying the load in each hour of the year by 1.02.

The reference case results assume a conservative level of available Southwest market supply. Increasing that supply by 500 megawatts lowers the 2023 LOLP to a little over 5 percent and only about 50 megawatts of additional capacity are needed to meet the Council's 5 percent standard. However, decreasing the Southwest market supply by 500 megawatts raises the LOLP to 8.6 percent and would require 1,050 megawatts of additional capacity.

Reducing the load forecast by 2 percent and increasing the Southwest market availability by 500 megawatts lowers the LOLP to 3.5 percent and no additional capacity is required for adequacy. However, increasing the load forecast by 2 percent and decreasing the Southwest market by 500 megawatts raises the LOLP to 12 percent and requires about 1,500 megawatts of additional capacity to satisfy the Council's adequacy standard.

Potential shortfall events for the 2023 operating year occur almost exclusively during December, January and February. Event durations range from a single hour to over 24 hours and average about 20 hours. The most common event duration is 16 hours, which occur over the commonly defined peak hours of the day. Events also tend to have a uniform hourly magnitude because, whenever possible, the hydro system is operated in a way to spread out projected shortfalls evenly across the peak hours of the day. For example, it is much easier to resolve a flat 100 megawatt shortfall over the 16 peak hours of the day than a 2-hour 800 megawatt shortfall.

THE COUNCIL'S RESOURCE ADEQUACY STANDARD

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to "provide an early warning should resource development fail to keep pace with demand growth." The standard defines an adequate power supply to be one in which the likelihood of a power supply shortfall is less than or equal to 5 percent.

The Council assesses adequacy using a stochastic analysis to compute the likelihood of a supply shortfall. It performs a chronological hourly simulation of the region's power supply over many different future combinations of stream flows, temperatures, wind generation patterns and forced generator outages. Besides targeted energy efficiency savings, existing generating resources are included, along with sited and licensed plants that are expected to be operational in the study year. The simulation also assumes a fixed amount of out-of-region market supply and explicitly models the economic dispatch of in-region merchant resources.

If the supply is deemed inadequate, the Council estimates how much additional capacity is required to bring the system's LOLP back down to 5 percent. However, this analysis is not intended to provide a resource-expansion target because it assesses only one of the Council's criteria for developing a power plan. The Council's mandate is to develop a resource strategy that provides an adequate, efficient, economic and reliable power supply. There is no guarantee that a power supply that satisfies the adequacy standard will also be the most economical or efficient. Thus, the adequacy standard should be thought of as simply an early warning to test for sufficient resource development.

Because the computer model used to assess adequacy (GENESYS) cannot possibly take into account all contingency actions that utilities have at their disposal to avert an actual loss of service, an LOLP greater than 5 percent should not be interpreted to mean that actual curtailments will occur. Rather, it means that the likelihood of utilities having to take extraordinary and costly measures to provide continuous service exceeds the tolerance for such events. Some utility emergency actions are captured in the LOLP assessment through a post-processing program that simulates the use of what the Council has termed "standby resources."

Standby resources are demand-side actions and small generators that are not explicitly modeled in the adequacy analysis. They are mainly composed of demand response measures, load curtailment agreements, small thermal resources and pumped storage at Banks Lake.

Demand response measures are expected to be used to help lower peak-hour demand during extreme conditions (e.g. high summer or low winter temperatures). These resources primarily provide peaking capacity and have a very limited amount of energy (i.e. once the assigned energy is used up, they are no longer available for dispatch). The effects of demand response measures that <u>have already been implemented</u> are assumed to be reflected in the Council's load forecast. New demand response measures that have no operating history and are, therefore, not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions, which are contractually available to utilities to help reduce peak hour load, and small generating resources may also provide some energy assistance. However, they are not intended to be used often. High usage of these resources is a good indicator that the underlying supply is inadequate. The energy and capacity capabilities of these non-modeled resources are aggregated along with the demand response measures mentioned above to define the total capability of standby resources. A post-processing program uses these capabilities along with the simulated curtailment record to calculate the final LOLP and other adequacy metrics.

RECENT ADEQUACY ASSESSMENTS

Table 1 below highlights the results of recent adequacy assessments. Since 1998, when the Council began using stochastic methods to assess adequacy, the power supply and, to some extent the methodology, have changed significantly, sometimes making it difficult to compare annual assessments. The evolution of adequacy assessments will continue and the Council has initiated efforts to improve its adequacy model and to revisit the viability of the current adequacy standard.

The Council recognizes that the power system of today is very different from that of 1980, when the Council was created by Congress. In particular, the trend for increasing penetration of variable energy resources, such as solar and wind, have added a greater band of uncertainty surrounding the adequacy assessment. This has led to a greater need for the ability to model hourly operations, especially for the hydroelectric system. Toward this end, the Council is currently in the process of redeveloping its adequacy model (GENESYS) to add more precision to the simulation of hydroelectric generation. The thrust of this effort is to improve the hourly operation simulation by adding a better representation of unit commitment, balancing reserve allocation and plant-specific hourly operations (the current model simulates hourly hydroelectric generation in aggregate for the region). These enhancements, expected to be completed by 2018, could likely change the results in a significant way. It will require an extensive vetting effort to ensure that the results of the redeveloped model are a better representation of expected operations.

Table 1: Reported[4] Adequacy Assessments

Year Analyzed	Operating Year	LOLP	Observations
2010	2015	5%	Was part of the Council's 6th Power Plan
2012	2017	7%	Imports decreased from 3,200 to 1,700 MW, load growth 150 aMW per year, only 114 MW of new thermal capacity
2014	2019	6%	Load growth 120 aMW per year, over 600 MW new generating capacity, increased imports by 800 MW
2015	2020	5%	Lower load forecast, 350 aMW of additional EE savings
2015	2021	8%	*Early estimate (BPA INC/DEC only)* Loss of Boardman and Centralia 1 (~1,330 MW)
2016	2021	10%	Including regional INC/DEC requirements reduces hydro peaking capability
2017	2021	6.9%	Lower LOLP primarily due to lower load forecast and shift in Canadian hydro operations
2017	2022	7.2%	LOLP increases slightly even with the loss of Colstrip 1 and 2 coal plants because of the 317 aMW of targeted EE savings for this year.
2018	2023	6.9%	No major resource change. LOLP drops slightly, due to improvements in the short-term load forecasting method

[4] The LOLP values in this table are the reported results from analyses performed at the time. Current estimations of LOLP values for the listed operating years could differ because of ongoing improvements to the GENESYS model and because of changes in operating assumptions (such as import availability).

2023 RESOURCE ADEQUACY ASSESSMENT

To ensure that sufficient time is available, if needed for resource acquisition, the Council's annual adequacy assessment looks at the status of the power supply five years out. However, because of the retirement of major generating resources starting in 2021, the Council has also looked at the adequacy for 2021 and 2022.

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the planned retirements of the Boardman and Centralia 1 coal plants (1,330 MW of nameplate capacity), the system will no longer meet the Council's adequacy standard in 2021. The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent. By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants and the Pasco gas-fired plant (479 megawatts combined).

In 2023 the LOLP is expected to remain at about 7 percent because no major resources are expected to retire and net load growth is expected to stay low. The increase in LOLP would be higher except for the Council's targeted energy efficiency savings and savings from codes and federal standards.

Additional capacity needed to maintain adequacy is estimated to be on the order of 300 megawatts in 2021 with an additional need for 300 to 400 megawatts in 2022. These amounts of needed capacity are estimated by adding combustion turbines to the future power supply as surrogate replacement resources. Of course, the actual amount of resource capacity needed for adequacy varies by resource type and, in fact, future resource additions will most certainly be a mix of different types of resources. Selecting the most cost effective and appropriate resources to acquire is beyond the scope of this analysis and is treated explicitly in the Council's power plan.

Sensitivity Analysis

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability in the out-of-region market supply.[5] Long-term load uncertainty for this analysis covers a 2-percent range around the mean. The out-of-region market is limited to only include California surplus generation. Thus, variation in the market supply is influenced only by future resource development (and retirements) in California and by the ability to transfer surplus energy from California into the

[5] Another potential random variable not currently modeled is the availability of transmission (outages and maintenance).

Northwest. For the sensitivity analysis, market availability was allowed to range from a low of 1,500 megawatts to a high of 3,000 megawatts from October through March.[6]

Table 2 summarizes the results of the market and load growth sensitivity analysis for 2023. In the extreme case, with high load growth and low import, the loss of load probability is over 14 percent. Fortunately, this scenario is not very likely. At the other extreme, with low load growth and maximum import availability, the loss of load probability drops to about 3.5 percent. The cells in Table 2 are color coded to better highlight conditions that lead to inadequate supplies. Red cells indicate an inadequate power supply with LOLP values greater than 5 percent and green cells indicate the power supply meets the Council's standard.

Table 2: 2023 Loss of Load Probability (LOLP in %)

Import (MW)	1500	2000	2500	3000
High Load +2%	14.3	12.1	10.1	7.8
Medium Load	11.0	8.6	6.9	5.1
Low Load -2%	8.0	6.4	4.9	3.5

Table 3 shows how much additional capacity[7] is required for each scenario to maintain adequacy (i.e. to get the LOLP down to the Council's 5 percent standard). In the extreme case, the region would need to acquire about 1,650 megawatts of capacity to maintain an adequate supply. At the other extreme, with low load growth and maximum import availability, no additional capacity is required for adequacy. Again for this table, the cells are color coded with red cells indicating conditions when additional capacity is required and green cells indicating that no additional capacity is needed.

[6] The Council also modeled a separate out-of-region market, namely a purchase-ahead market, which is available all year but allows imports only during non-peak hours and only if a shortfall is expected in the following day or week.

[7] Additional capacity needed to maintain adequacy is estimated using combustion turbines as the surrogate acquisition resources.

Table 3: 2023 Estimated Capacity Needed to Maintain Adequacy (MW)

Import (MW)	1500	2000	2500	3000
High Load +2%	1650	1500	1100	600
Medium Load	1400	1050	650	50
Low Load -2%	950	550	0	0

Monthly Analysis

As discovered during the development of the Council's Seventh Power Plan, it is also important to assess monthly adequacy values in order to better inform the Council's resource acquisition methodology. For example, some resources such as demand response are only seasonally available (e.g. in winter or in summer only).

Figure 1 below highlights the monthly LOLP values for the 2023 operating year.[8] Results show that the Northwest is still a winter peaking region. However, some longer-term load forecasts indicate that the region will begin to see a higher likelihood of summer shortfalls within the next ten years. The small LOLP values for September and October are likely false positive results because of import availability assumptions. The analysis assumes no market availability in September and only half of the expected winter amount in October. Discussions among members of the Resource Adequacy Advisory Committee indicate that these assumptions may be too conservative. The small LOLP result in November reflects the beginning of the winter heating period.

Table 4 summarizes the monthly average dispatch for blocks of resources, namely wind, solar, coal, gas, nuclear and the market (which includes both within-region and out-of-region supplies).

[8] It should be noted that the sum of monthly LOLP values will always be equal to or greater than the annual LOLP value because of the way in which the Council has defined its standard. The annual LOLP counts simulations with at least one curtailment event regardless of when it occurs. A simulation with multiple events, say one in January and one in August, would count the same toward the annual LOLP value as a simulation with only a January event or only an August event.

Figure 1: 2023 LOLP by Month

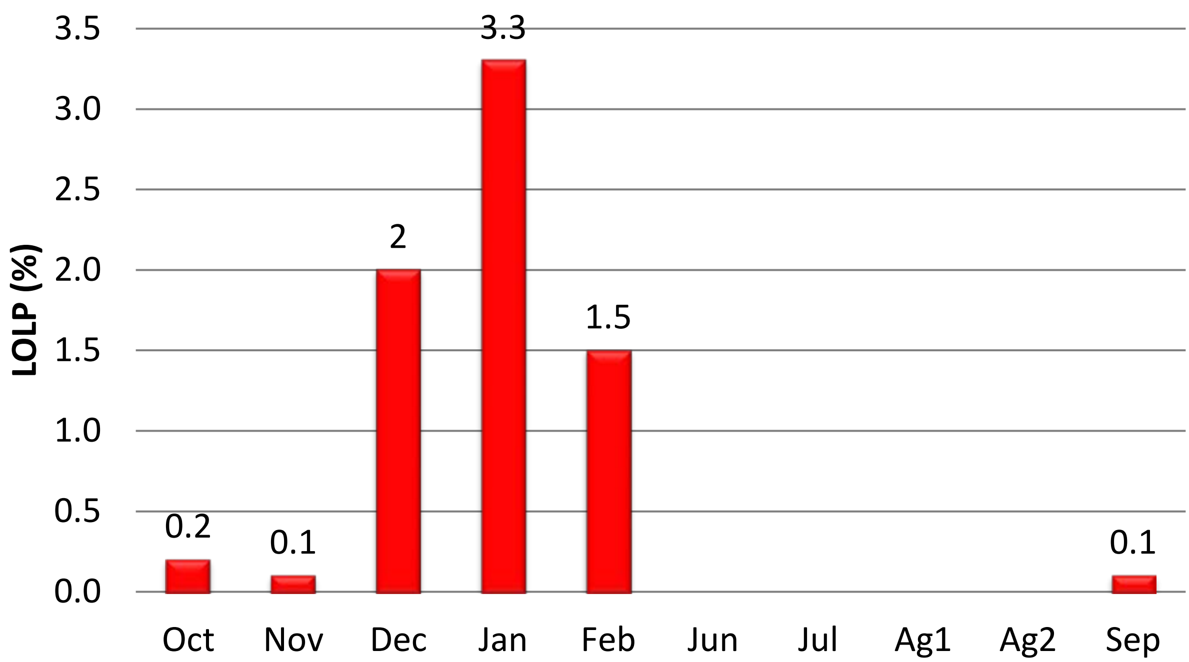

Table 4: Expected Resource Dispatch (aMW) for 2023

	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Solar	141	79	63	70	108	128	159	161	172	175	194	192	176	176
Wind	1246	1302	1222	1343	1351	1617	1841	1920	1806	1785	1638	1532	1408	1210
Coal	3238	2879	3116	2603	2402	2174	1787	1044	352	707	1801	2891	3182	3395
Gas	2975	1416	2087	1876	1610	1094	985	511	412	584	969	1647	2202	2537
Nuclear	1109	1117	1150	1155	1106	1157	1081	1075	1157	1134	1159	1077	1098	1135
Market	459	544	890	799	611	402	307	83	25	39	102	215	301	348

Curtailment Statistics

Curtailment statistics can sometimes provide valuable insight into the behavior of the power system. Table 5 below summarizes several key statistics from the simulated curtailment record for 2023. All adequacy studies were run with 7,040 simulations (which include all combinations of the historical 80-year water record with the historical 88-year temperature record).

The red-colored row in Table 5 highlights the Council's current measure for adequacy, namely a 5-percent maximum for annual LOLP. The green-colored rows highlight metrics currently proposed by the North American Reliability Corporation for reporting. However, NERC does not specify a threshold for its proposed metrics (e.g. a maximum level beyond which the power supply is deemed to be inadequate).

Table 5: 2023 Curtailment Statistics

Statistic	Value	Units
Number of simulations	7,040	Number
Simulations with a curtailment	486	Number
Loss of load probability (LOLP)	6.9	Percent
Number of curtailment events	1,018	Number
Loss of load events (LOLEV)	0.14	Events/year
Average time between events	7	years
Average event peak-hour curtailment	1,800	MW
Average event magnitude	42,500	MW-hours
Average event duration	21	hours
Conditional value at risk (CVaR) peak	3,216	MW
Conditional value at risk (CVaR) energy	121,900	MW-hours
Expected un-served energy (EUE)	6,190	MW-hours
Expected curtailed hours per year (LOLH)	3.0	Hours

An interesting result from Table 5 is the value for the Loss-of-Load-Events (LOLEV) metric. This metric measures the frequency of shortfall events and is the most relevant metric to compare to the historic 1-in-10 year standard. If the "1-in-10" refers to 1-event-in-10 years, then the implied adequacy threshold for LOLEV should be 0.1 events/year. Because the reference case LOLEV of 0.14 events/year (or 1 event in 7 years) exceeds this threshold, we conclude that the reference case does not comply with the 1-in-10 year standard. However, adding sufficient capacity to bring the 2023 LOLP down to the 5 percent level yields an LOLEV of close to 0.1 events/year, which means that when the regional power supply meets the 5 percent LOLP standard, its corresponding LOLEV value is consistent with a 1-event-in-10 year threshold (at least for this one example).

Besides looking at curtailment statistics, it may also be of great value to examine the conditions under which curtailments occurred. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis is provided on the Council's Resource Adequacy website). The four random variables are;

- Monthly river flow volume, as measured at The Dalles Dam
- Daily average regional temperature
- Variable energy resource generation (wind and solar)
- Thermal resource forced outages

Some attempts have been made to correlate shortfall events with the occurrence of certain temperatures, water conditions, wind generation patterns and forced outages, but unfortunately without much success. This is an area of study that is being explored further and may produce better results once the GENESYS model has been enhanced to model plant-specific hourly hydroelectric operations.

Figure 2 displays the event duration histogram, which shows the number of events observed for each event duration up to 24 hours. Not shown are about 20 percent of events that last longer than 24 hours (e.g. are multiple day events). In Figure 2, the x-axis represents event duration and the y-axis represents number of events with that duration. What stands out is that the most common event duration is 16 hours. This is not unexpected because, by design, the hydroelectric system's output is adjusted, whenever possible, to spread any anticipated unserved energy across all 16 peak hours of the day. This produces a relatively flat amount of hourly unserved energy, which is easier to rectify than a shorter duration, higher magnitude and non-uniform shortfall.

From Figure 2, the fact that almost 30 percent of events have a duration less than 8 hours bodes well for demand response and other short-term standby measures. For example, the LOLP of the 2023 power supply prior to applying the effects of standby resources is 8 percent but accounting for standby resources (740 megawatts of capacity in winter and 1,140 megawatts in summer) drops the LOLP to 6.9 percent. Thus, although demand response and other short-term measures can only be applied over several hours, they are nonetheless very effective in eliminating short-duration events (e.g. picking the low hanging fruit, in colloquial terms).

Figure 3 shows the number of shortfall events by month and Figure 4 shows the average peak-hour shortfall by month. As expected, the bulk of simulated shortfall events for 2023 occur in winter months (December, January and February). However, shortfalls can also occur in other months, in particular, during the summer. Although the current load forecast and adequacy assessment still show the region as being winter-peaking, the gap between resources and loads is narrowing for summer months. Separate analyses (for years beyond the 5-year scope of this work) indicate that summer shortfalls will begin to appear in greater numbers and that they will likely have smaller magnitude but will occur more frequently than winter shortfalls.

Figure 2: Event Duration Histogram

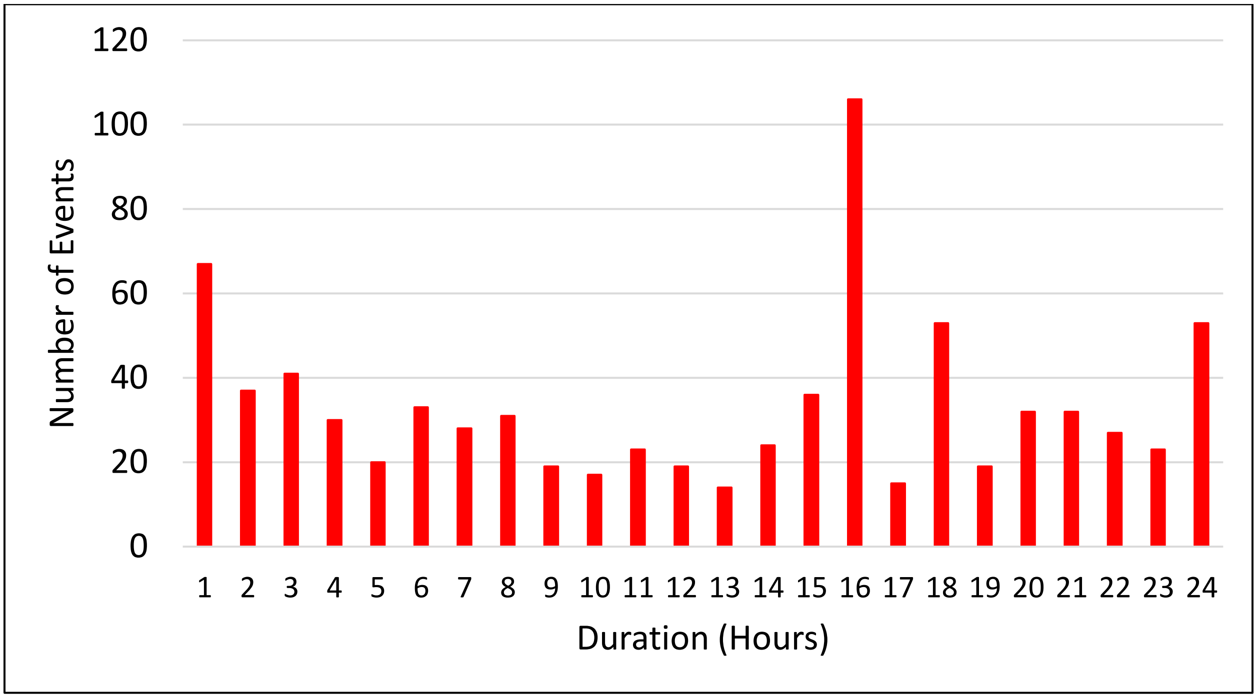

Figure 3: Number of Events per Month

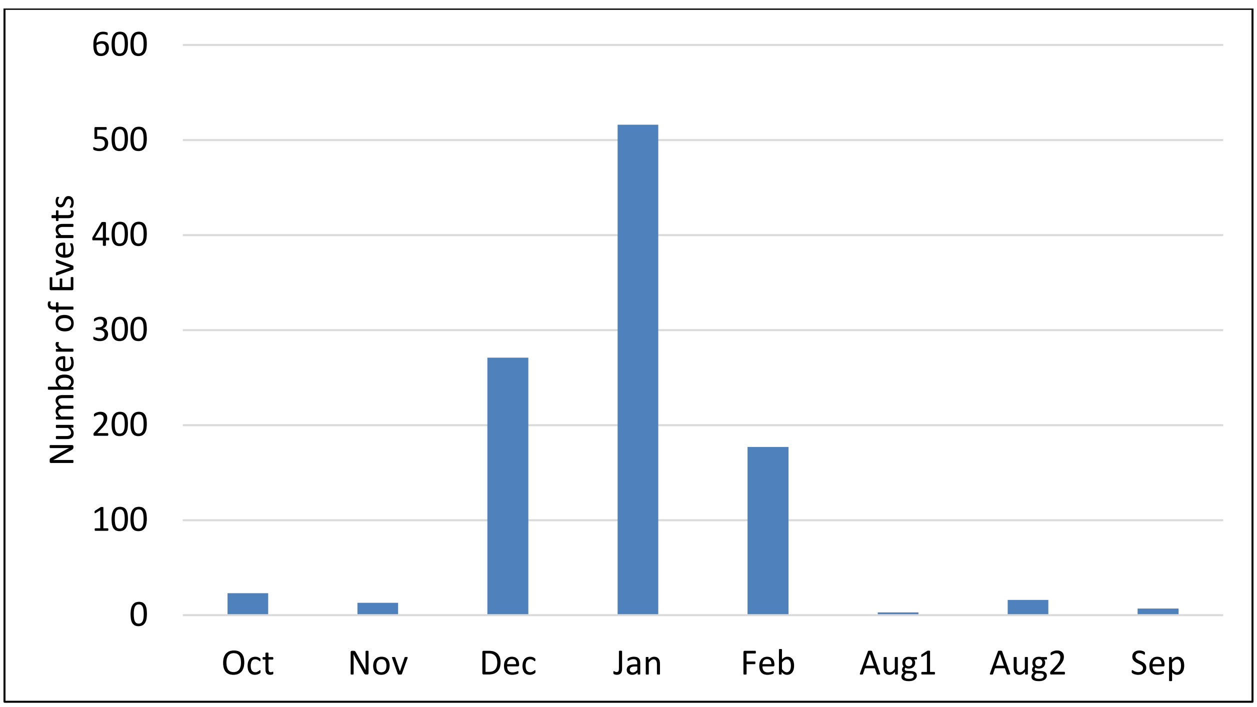

Figure 4: Average Peak-Hour Curtailment per Month

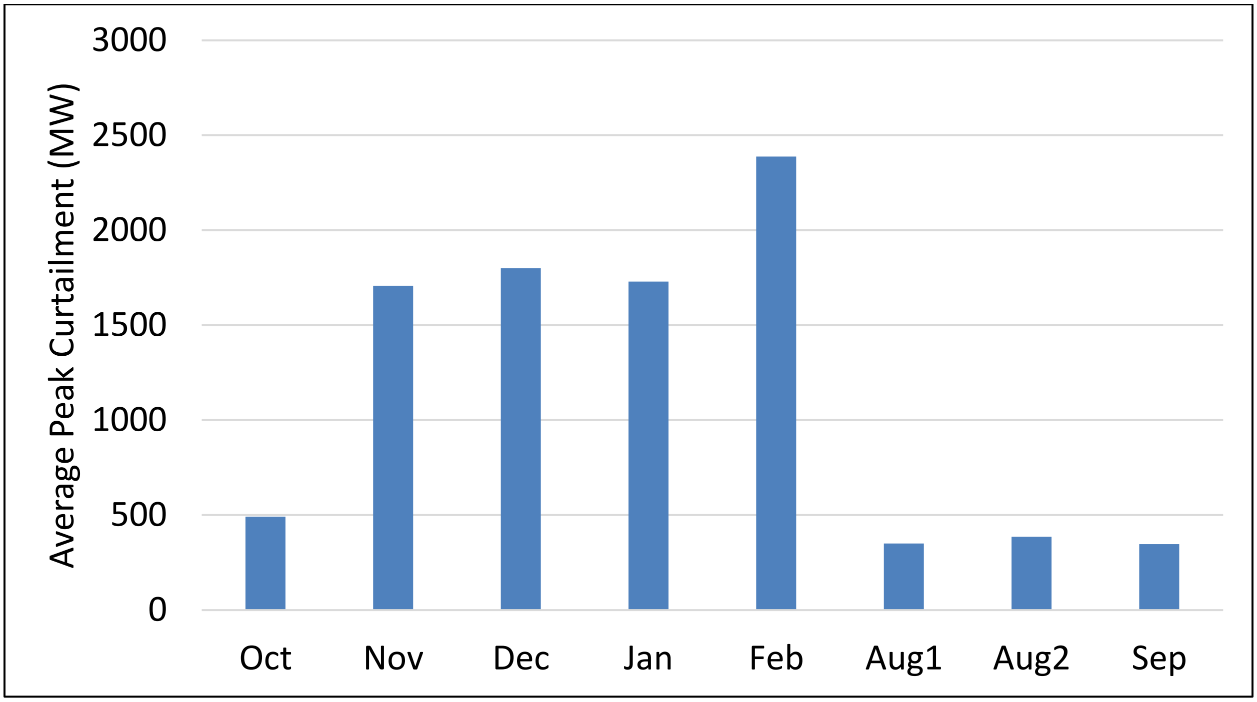

Figure 5 below shows the number of shortfall events by historic water year and Figure 6 shows the number of events by historic temperature year. From Figure 5, regardless of temperature, the 1930, 1932 and 1993 historic river flows provide the worst conditions for adequacy and produce over 20 percent of all simulated shortfall events. From Figure 6, regardless of river flows, 1950 out of all the historic temperature years provides the worst conditions for adequacy, producing 16 percent of all simulated shortfall events.

Finally, Table 6 shows combinations of water and temperature years with the worst conditions for adequacy. From this table, no particular combination of water and temperature year stands out as being significantly worse than other combinations. It should be noted, however, that of the four random variables (or unknown future conditions) river flow and temperature (load) uncertainty have the most significant influence on power supply adequacy.

Figure 5: Number of Events by Water Year

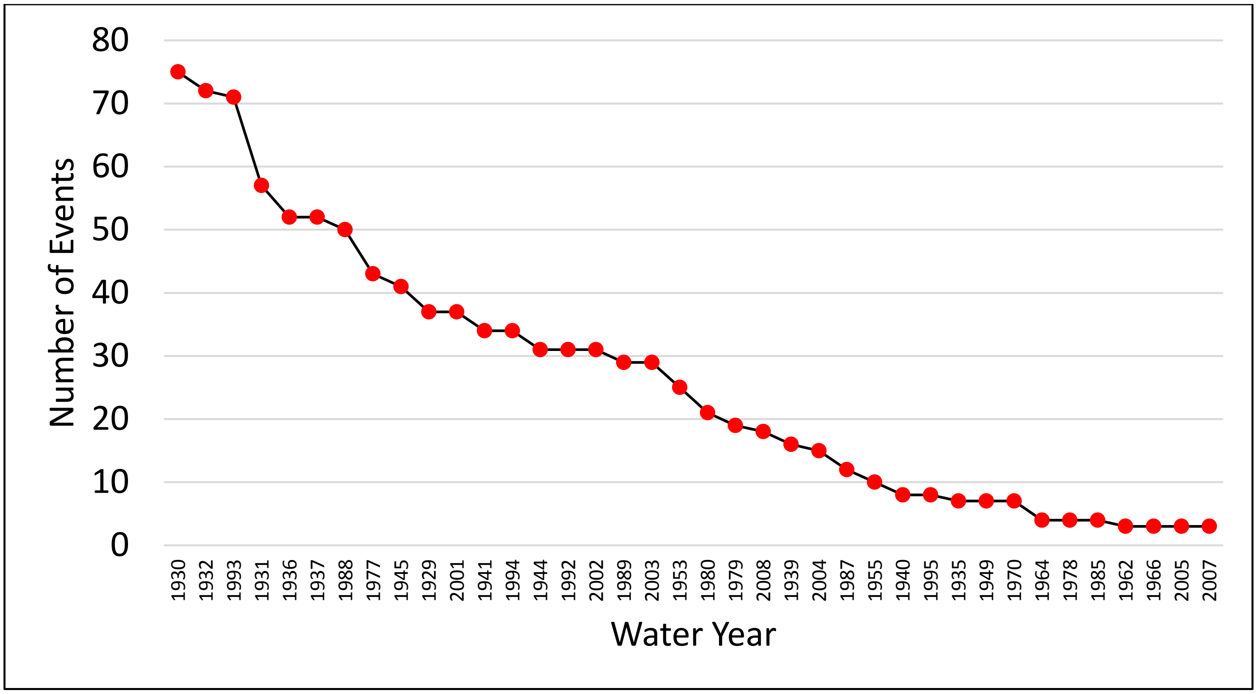

Figure 6: Number of Events by Temperature Year

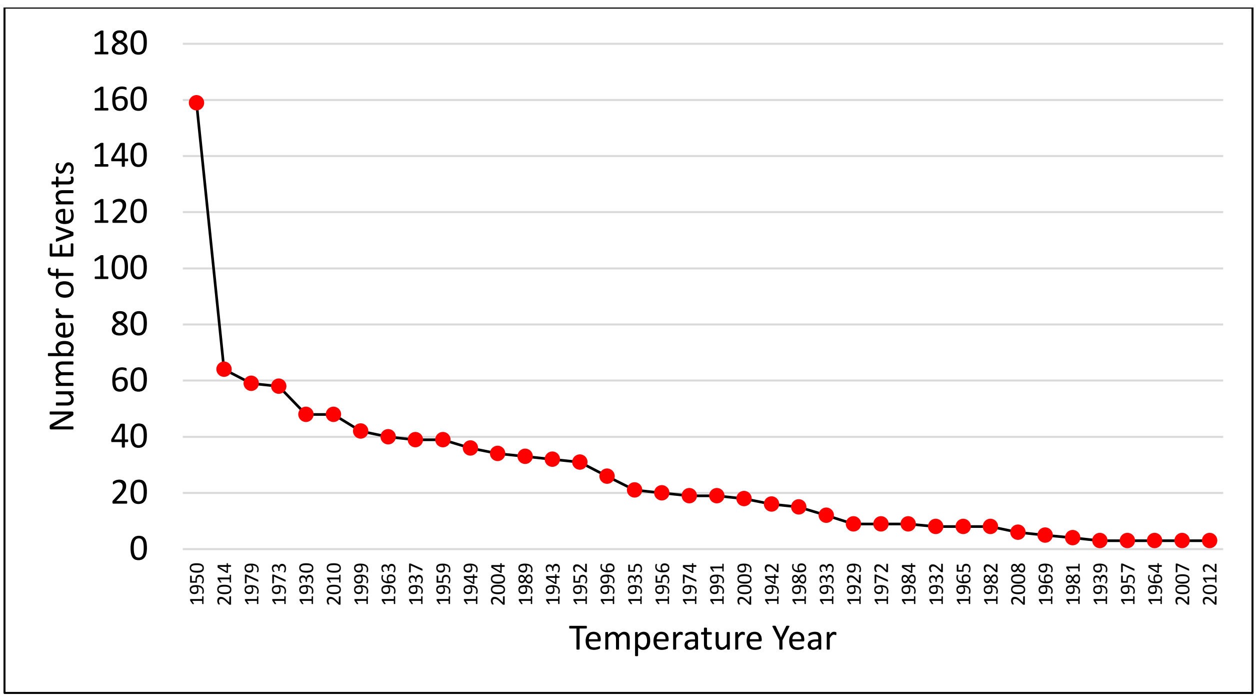

Table 6: Water Year/Temperature Year Combinations with the most Shortfalls

Water Year	Temp Year	Number of Events
1930	1930	10
1993	1930	9
1944	1950	8
1977	1950	8
1930	1937	7
1931	1950	7
1932	1930	7
1937	1930	7
1945	1950	7
1994	1930	7
1930	1950	6
1932	1937	6
1932	1949	6
1932	1950	6
1941	1950	6
1988	1973	6
1989	1950	6

Other Adequacy Metrics

Adequacy metrics help planners better understand the magnitude, frequency and duration of potential future power supply shortfalls. These metrics provide valuable information to planners as they consider resource expansion strategies. Table 7 below provides the definitions for some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 8 shows the value of these metrics for the region for 2023 and past years.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It asked that each of its sub-regions in the United States provide three adequacy measures; 1) expected loss of load hours, 2) expected unserved energy and 3) normalized expected unserved energy (EUE divided by load). This effort is a good first step toward standardizing how adequacy is measured across the United States. However NERC is not tasked with setting nationwide thresholds for these metrics. In fact, it may be impossible to do so because power supplies vary drastically across regions.

While the Council has successfully used the annual LOLP metric to assess adequacy for over a decade, it became evident during the development of the Seventh Power Plan that seasonal adequacy targets will be necessary to develop future power plans. The Council's Regional Portfolio Model uses quarterly reserve margin targets, derived from quarterly LOLP thresholds, to test for adequacy. Using a flat 5 percent annual

LOLP to set quarterly reserve margins could result in power supplies that are not adequate. In other words, if the adequacy test in the RPM is a quarterly 5 percent LOLP, it is possible for a power supply that meets the 5 percent quarterly threshold to have an annual LOLP of nearly 20 percent. This can happen if curtailments in each quarter occur in different years. Thus, the calculation of quarterly adequacy reserve margins requires quarterly adequacy targets. Recognizing this, the Council added an action item to its Seventh Power Plan to review and amend its current adequacy standard, as necessary, to more accurately calculate seasonal planning reserve margins.

Table 9 shows the monthly values for these metrics for the 2023 reference case and tables 10-13 show how some of these metrics change under different load and import availability assumptions made for the sensitivity scenarios described above.

Table 7: Adequacy Metric Definitions

Metric	Description
LOLP (%)	Loss of load probability = number of games with a problem divided by the total number of games
CVaR – Energy (GW-hours)	Conditional value at risk, energy = average annual curtailment for 5% worst games
CVaR – Peak (MW)	Conditional value at risk, peak = average single-hour curtailment for worst 5% of games
EUE (MW-hours)	Expected unserved energy = total curtailment divided by the total number of games
Normalized EUE (ppm)	Normalized expected unserved energy = EUE divided by average load (in MW-hours) multiplied by 1,000,000 in units of parts per million
LOLH (Hours)	Loss of load hours = total number of hours of curtailment divided by total number of games
LOLEV (Events/year)	Loss of load events = total number of curtailment events divided by the total number of simulations

Table 8: Annual Adequacy Metrics (Base Case)

Metric	2017	2019	2020	2021	2022	2023	Units
LOLP	6.6	5.9	4.7	6.9	7.2	6.9	Percent
CVaR - Energy	99.0	59.2	50.6	34.7	40.5	122	GW-hours
CVaR - Peak	4,000	3,337	2,949	1,563	1,625	3,216	MW
EUE	5,000	3,000	2,536	1,743	2,038	6,190	MW-hours
Normalized EUE	N/A	N/A	N/A	N/A	11.6	33.1	PPM
LOLH	2.7	1.7	1.5	1.4	1.6	3.0	Hours/year
LOLEV	N/A	N/A	N/A	N/A	0.14	0.14	Events/year

Table 9: 2023 Monthly Adequacy Metrics (Reference Case)

Month	**LOLP** (%)	**CVaR Energy** (GW-hours)	**CVaR Peak** (MW)	**EUE** (MW-ours)	**NEUE** (ppm)	**LOLH** (hours)
Oct	0.2	134	24	6	1	0.017
Nov	0.1	932	57	46	3	0.027
Dec	2.0	29121	1058	1456	81	0.812
Jan	3.3	57748	1596	2887	159	1.509
Feb	1.5	35720	1072	1786	115	0.621
Ag1	0.0	18	3	1	0.1	0.003
Ag2	0.2	99	16	5	1	0.014
Sep	0.1	23	6	1	0.1	0.004

Table 10: Expected Unserved Energy (EUE in GW-hours)

Import (MW)	1500	2000	2500	3000
High Load	18.0	13.0	9.8	6.2
Med Load	11.5	8.4	6.2	3.9
Low Load	7.3	5.3	3.8	2.3

Table 11: Loss of Load Hours (LOLH in Hours)

Import (MW)	1500	2000	2500	3000
High Load	7.4	5.9	4.6	3.0
Med Load	5.1	3.9	3.0	1.9
Low Load	3.4	2.6	1.9	1.2

Table 12: Conditional Value at Risk for Peak (CVaR Peak in GW)

Import (MW)	1500	2000	2500	3000
High Load	5.3	4.7	4.0	3.3
Med Load	4.5	3.9	3.2	2.4
Low Load	3.7	3.0	2.3	1.5

Table13: Conditional Value at Risk for Energy (CVaR Energy in GW-hours)

Import (MW)	1500	2000	2500	3000
High Load	290	233	184	123
Med Load	205	160	122	78
Low Load	140	105	76	47

Resource and Load Data

Tables 14-20 summarize the resources and load forecasts used for the 2023 adequacy assessment. Table 14 displays the annual average load and the winter and summer peak loads along with the assumed out-of-region market availability. Tables 15-17 provide the energy and capacity contributions for generating and standby resources. Table 18 shows the monthly breakdown of firm contracts, both into and out of the region. Tables 19 and 20 provide the monthly incremental and decremental balancing reserves that are held by the hydroelectric system.

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on market supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,273 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with California utilities, the Northwest market availability is limited to 1,000 megawatts.

Table 14: Loads and Import Availability for 2023

Item	Oct-Mar	Apr-Sep
Average Load (aMW)	21,353	
Avg. Peak Load (MW)	33,649	26,755
DSI Load (aMW)	421	421
Spot Imports (MW)	2,500[9]	0
Purchase Ahead (MW)	3,000	3,000

[9] For October, the spot market availability is set to 1,250 megawatts.

Table 15: Generating Resources

Annual Values	2022	2023	Difference
Nuclear (MW)	1,144	1,144	0
Coal (MW)	3,232	3,323	0
Gas and Misc (MW)	7,497	7,877	380
IPP (MW)	2,653	2,273	(380)
Total Thermal Resource	**14,661**	**14,661**	**0**
Wind Nameplate (MW)	4,906	5,098	202
Solar Nameplate (MW)	407	550	143

Table 16: Standby Resources – Peak (MW)

Item	Oct-Mar	Apr-Sep
Exist DR	452	852
Emergency Generation	288	288
Total Existing	**740**	**1,140**

Table 17: Standby Resources – Energy (MW-hours)

Item	Oct-Mar	Apr-Sep
Monsanto Curtailment	35,000	35,000
Emergency Generation	6,900	6,900
Total Existing	**41,900**	**41,900**

Table 18: Firm Energy Contracts (aMW)

2023	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep
Imports	22	40	51	65	71	63	30	30	30	39	28	21	21	16
PNW West/Canada	455	455	455	455	455	455	473	437	455	455	479	568	572	455
PNW West/S Cal	21	18	13	7	11	13	23	27	29	28	28	18	23	22
Total Exports	476	473	468	462	466	468	496	464	484	483	507	586	595	477

2022	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep
Imports	9	17	21	27	30	26	13	12	13	16	11	9	9	7
PNW West/Canada	434	476	435	476	454	454	413	413	498	454	442	511	509	429
PNW West/S Cal	32	18	16	14	13	22	27	30	29	92	196	23	31	29
Total Exports	466	494	451	490	467	476	440	443	527	546	638	534	540	458

Difference in Firm Contracts (2023 – 2022)

2023 – 2022	Oct	Nov	Dec	Jan	Feb	Mar	Ap1	Ap2	May	Jun	Jul	Au1	Au2	Sep
Imports	13	23	30	38	41	37	17	18	17	23	17	12	12	9
PNW West/Canada	21	-21	20	-21	1	1	60	24	-43	1	37	57	63	26
PNW West/S Cal	-11	0	-3	-7	-2	-9	-4	-3	0	-64	-168	-5	-8	-7
Total Exports	10	-21	17	-28	-1	-8	56	21	-43	-63	-131	52	55	19

Tables 19 and 20 show the monthly balancing reserves (incremental and decremental) held by the hydroelectric system. Using the Council's hourly hydroelectric optimization program (TRAP model), a portion of the peaking capability and an amount of minimum generation at specific hydroelectric projects is reserved to support the within-hour balancing needs. Unfortunately, not all balancing reserves could be assigned to the hydroelectric system. The remaining reserves would be assigned to other resources but GENESYS does not currently have the capability to simulate thermal reserves. This is one of the major enhancements targeted in the GENESYS redevelopment process.

Table 19: BPA Within-hour Balancing Reserves – Incremental (MW)

Period	2022	2023
October	900	602
November	900	602
December	900	602
January	900	602
February	900	602
March	900	602
April 1-15	400	602
April 16-30	400	602
May	400	602
June	400	602
July	900	602
August 1-15	900	602
August 16-31	900	602
September	900	602

Table 20: Within-hour Balancing Reserves – Decremental (MW)

Period	2022	2023
October	662	729
November	899	729
December	687	729
January	751	729
February	728	729
March	690	729
April 1-15	713	729
April 16-30	713	729
May	748	729
June	723	729
July	629	729
August 1-15	609	729
August 16-31	609	729
September	746	729

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply annually as a check for power supply adequacy. This task is becoming more challenging because of continued development of variable generation resources and changing load patterns. For example, regional planners have had to reevaluate methods to quantify and plan for balancing reserve needs. In light of these changes, the Council is in the process of enhancing its adequacy model to represent operations at a more granular level and to address capacity issues.

Another emerging concern is accounting for transmission access to market supplies. For the current adequacy assessment, the Northwest region is split into two sub-regions[10] in which only the major east-to-west transmission lines are modeled along

[10] The dividing line between the east and west areas of the region (for modeling purposes) is roughly the Cascade mountain range.

with the major out-of-region interties. The Council is exploring how to address these issues for future adequacy assessments.

The Council's Seventh Power Plan identifies the following action items related to adequacy assessments:

RES-8	Adaptive Management – Annual Resource Adequacy Assessments
COUN-3	Review the regional resource adequacy standard
COUN-4	Review the RAAC assumptions regarding availability of imports
COUN-5	Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model
COUN-6	Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model
COUN-8	Participate in and track WECC [adequacy] activities
COUN-11	Participate in efforts to update and model climate change data
ANLYS-4	Review and enhancement of peak load forecasting
ANLYS-22	GENESYS Model Redevelopment
ANLYS-23	Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations

Issues identified in 2018 by the Council's Resource Adequacy Advisory Committee to consider for future assessments include:

- Review and update the availability of California market supplies for all months and all hours.
- Investigate ways to incorporate uncertainty in EE savings into adequacy assessments.
- Investigate the availability of the interties that connect the NW with regions that may provide market supplies. Consider adding maintenance schedules and forced outages.
- Explore ways to incorporate the effects of climate change into the adequacy assessments.
- Develop a method to explicitly model the use of standby resources for adequacy assessments, in particular demand response and storage.

Not all of the action items and recommendations listed above will be addressed and resolved before the next adequacy assessment, which is tentatively scheduled for release in June of 2019. However, any enhancements that can be made and tested in time for the next assessment will be implemented.

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