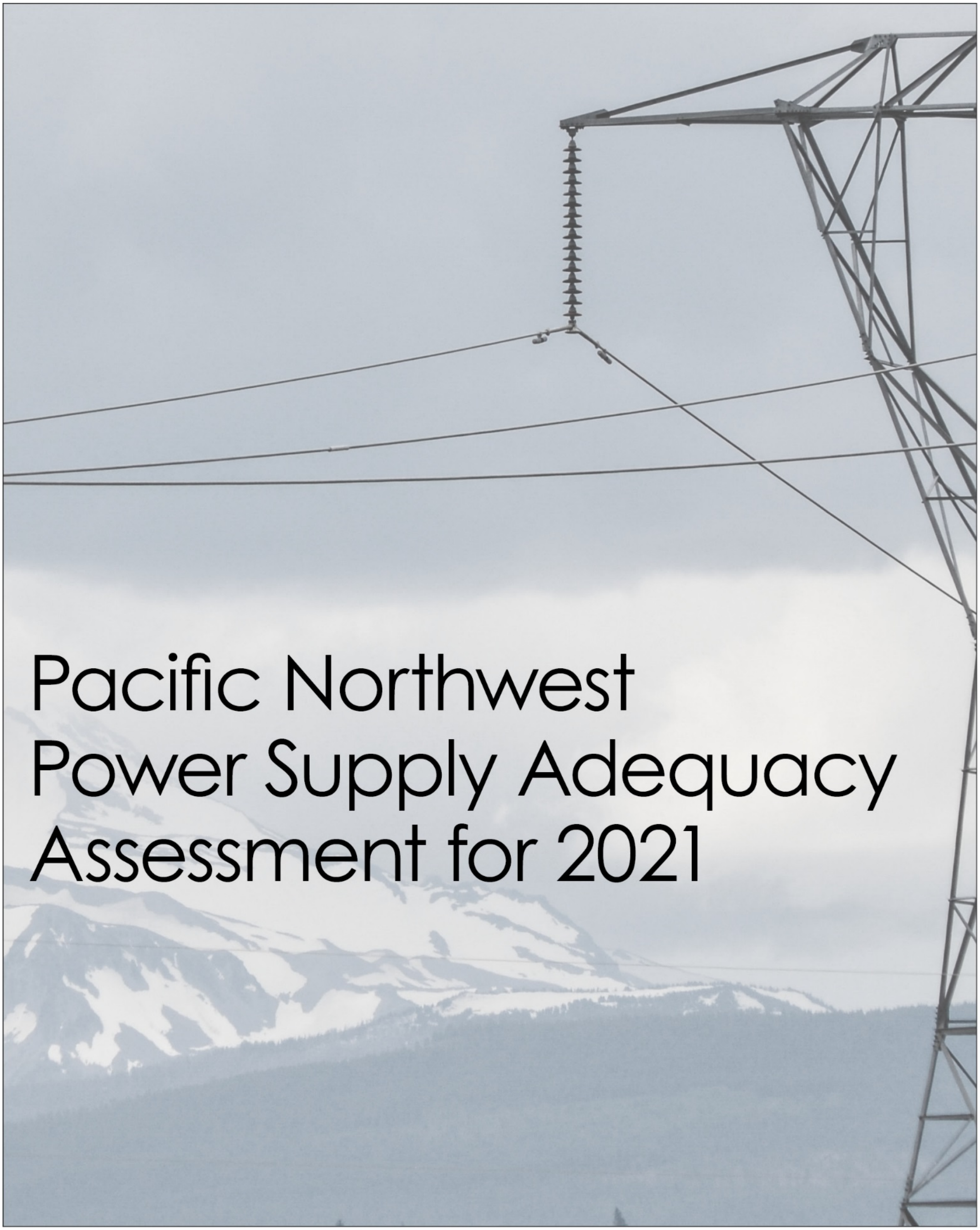

Pacific Northwest Power Supply Adequacy Assessment for 2021

September 27, 2016
Document 2016-10

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 2021 operating year (October through September). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for power supply adequacy and set the 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.

Other adequacy metrics that measure the size of potential shortages, how often they occur and how long they last, also provide valuable information to planners as they consider resource expansion strategies. This report provides that information along with other statistical data derived from Council analyses. The Council, with the help of the Resource Adequacy Advisory Committee, produced the data in the charts and tables.

The format and content of this report continue to be under development. We would like to know how useful this report is for you. For example, is the format appropriate? Would you like to see different types of output? Please send your comments, suggestions and questions to John Fazio at (jfazio@nwcouncil.org).

The Council is improving its adequacy model (GENESYS), in particular the hourly hydroelectric system dispatch simulation, and expects to complete the work by 2018. In addition, the Council has initiated a process to review its current adequacy standard. Staff and RAAC members have been 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).

Cover photo courtesy of SOAR Oregon.

EXECUTIVE SUMMARY

The Pacific Northwest's power supply should be adequate through 2020. However, with the planned retirements of four Northwest coal plants[1] by July of 2022, the system will no longer meet the Council's adequacy standard and will have to acquire nearly 1,400 megawatts of new capacity in order to maintain that standard. This result assumes that the region will meet the Council's energy efficiency targets, as identified in the Seventh Power Plan. Thus, it is imperative that we continue to implement cost-effective energy efficiency programs. Beyond energy efficiency, Northwest utilities have been steadily working to develop replacement resource strategies and have reported about 550 megawatts of planned generating capacity by 2021.[2] These strategies will include the next most cost-effective and implementable resources, which may include additional energy efficiency, demand response or new generating resources. The Council will reassess the adequacy of the power supply next year to monitor the region's progress in maintaining resource adequacy.

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 deems the power supply to be inadequate if the likelihood of a power supply shortfall (referred to as the loss-of-load probability or LOLP) is higher than 5 percent. The LOLP for the region's power supply should stay under the 5 percent limit through 2020. In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.[3] In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire before 2021,[4] the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

These results are based on a stochastic analysis that simulates the operation of the power supply over thousands of different combinations of river flow, wind generation, forced outages, and temperatures. Since last year's assessment for 2021, which resulted in an 8 percent LOLP,

[1] Centralia 1 (670 megawatts) and Boardman (522 megawatts) are scheduled to retire by December 2020, Colstrip 1 and 2 (154 megawatts each) are to be retired no later than July of 2022 and Centralia 2 (670 megawatts) is expected to retire by 2025.

[2] From the Pacific Northwest Utility Conference Committee's 2016 Northwest Regional Forecast (NRF).

[3] Boardman and Centralia 1 coal plants are scheduled to retire in December 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long-term effects of these retirements, and therefore uses the more generic study that has both plants out for the entire operating year.

[4] Currently there is no indication that Colstrip plants 3 and 4 will be retired earlier than expected.

the region's load forecast has slightly decreased[5] and no new resources have been added. This year's LOLP assessment for 2021 has grown to 10 percent because it included all regional balancing reserve requirements instead of only the federal system reserves assumed in last year's analysis.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 30 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But these extreme cases are not very likely to occur.

Resource acquisition plans to bring the 2021 power supply into compliance with the Council's standard will vary depending on the types of new generating resources or demand reduction programs that are considered. In all likelihood, utilities will use some combination of new generation and load reduction programs to bridge the gap.

This analysis does not provide a strategy to maintain an adequate, efficient, economical, and reliable power supply. The Council's Seventh Power Plan outlines a resource strategy to ensure an adequate power supply for 2021.

Northwest utilities, as reported in the Pacific Northwest Utilities Conference Committee's 2016 Northwest Regional Forecast, show about 550 megawatts of planned generating capacity for 2021. However, these planned resources are not sited and licensed and are therefore not included in the 2021 adequacy assessment. As conditions change over the next few years, we expect utilities to revise their resource acquisition strategies to invest in new resources, which include energy efficiency and demand response.

[5] This year's assessment included a hybrid load forecasting method that is different from past forecasts. This was done to insure that the load forecast used for the adequacy assessment was consistent with the one used for the development of the Council's Seventh Power Plan. The RAAC will evaluate this new load forecast in detail prior to next year's assessment for 2022.

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 deems the power supply to be inadequate if the likelihood of a power supply shortfall five years in the future is higher than 5 percent.

The Council assesses adequacy using a stochastic analysis to compute the likelihood of a supply shortfall. It uses 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. We only count existing generating resources, and those expected to be operational in the study year, along with targeted energy efficiency savings. The simulation also assumes a fixed amount of market resource availability, both from inside and outside of the region.

The power supply is deemed to be adequate if the likelihood of a shortfall (referred to as the loss of load probability or LOLP) is less than or equal to 5 percent. If the supply is deemed inadequate, the Council estimates how much additional capacity and energy generating capability is required to bring the system's LOLP back down to 5 percent. However, the standard is not intended to provide a resource-planning 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, a non-zero LOLP should not be interpreted to mean that real 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 emergency utility 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 and small thermal resources.

Demand response measures are typically expected to be used to help lower peak-hour demand during extreme conditions (e.g. high summer or low winter temperatures). These resources only have a capacity component and provide only a very limited amount of energy (i.e. they cannot be dispatched for more than a few hours at a time). The effects of demand response measures that have already been implemented 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 and are, therefore not modeled explicitly in the simulations. 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 to adjust the simulated curtailment record and calculate the final LOLP.

RECENT ADEQUACY ASSESSMENTS

Table 1 below illustrates the evolving nature of the effort to better quantify power supply adequacy. 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. And, while this evolution is likely to continue, the Council believes that the current standard and methodology will be sufficiently stable to create a history of adequacy evaluations that can be used to record trends over time.

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 ever increasing generation from variable energy resources, such as solar and wind, have added a greater band of uncertainty with regard to providing an adequate supply. This has led to a greater need in 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 moving to a plant-specific hourly hydroelectric simulation (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 real-life operations. It will be important to identify the effects of the model enhancements to the resulting adequacy assessments and separate them from the effects of real load and resource changes.

Table 1: History of Adequacy Assessment

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%	2021 loads lower than last year's forecast regional INC/DEC reduces hydro peaking
2016	2021	13%	Same as above but with Colstrip coal plants 1 and 2 retired (307 MW assigned to serve the region)

2021 RESOURCE ADEQUACY ASSESSMENT

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the planned retirements of four Northwest coal plants by July of 2022, the system will no longer meet the Council's adequacy standard (LOLP at 13 percent) and will have to acquire nearly 1,400 megawatts of new capacity in order to reduce the LOLP to the 5 percent standard. This result assumes that the Council's energy efficiency targets, as identified in the Seventh Power Plan, will be achieved.

In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.[6] In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire

[6] Boardman and Centralia 1 coal plants are scheduled to retire in December 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long-term effects of these retirements, and therefore uses the more generic study that has both plants out for the entire operating year.

before 2021, the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 26 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But this extreme case is not very likely to occur.

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability of the out-of-region market supply. Long-term load growth is bounded by the Council's high and low load forecasts, which cover roughly 85 percent of the expected load range. Variation in SW market supply is influenced by future resource development in California and by the ability to transfer surplus energy into the Northwest.

By 2021, California is scheduled to retire 2,641 megawatts of its coastal water-cooled thermal power plants, and nearly 10,000 megawatts will either be retired or replaced over the next 10 years. In addition, in 2012 California lost 2,200 megawatts of San Onofre Nuclear Generating Station capacity.[7] However, according to an Energy GPS report, California surplus is expected to greatly exceed the south-to-north intertie transfer capability during Northwest winter peak-load hours. Based on a look at historical monthly south-to-north transfer availability (BPA data), it appears that the maximum transfer capability hovers around 4,500 megawatts with a 95 percent chance of being at least 3,400 megawatts. The Council chose to set the maximum transfer capability from California into the Northwest to the 3,400 megawatt value.

In spite of the results of the Energy GPS survey of available California surplus, and supported by the Resource Adequacy Advisory Committee, the Council chose to limit California import availability to no more than 2,500 megawatts during peak hours in the winter and to 3,000 megawatts during off-peak hours year round. The on-peak imports are defined as a "spot market" resource, which can be acquired during the hour of need. The off-peak imports are defined as a "purchase ahead" resource, which can be acquired during the light-loads hours prior to an anticipated peak-hour shortfall.

To investigate the potential impacts of different combinations of economic load growth and California import availability, scenario analyses were performed. In one extreme case, with high load growth and no California import, the loss of load probability would be 26 percent. Fortunately, this scenario is not very likely. At the other end of extreme cases, with low load growth and maximum winter import availability, the loss of load probability drops to about 2 percent. Table 2 illustrates how LOLP changes as both long-term load growth and SW imports vary.

[7] By 2025 the Diablo Canyon nuclear plant (2,200 megawatts) is expected to close.

Table 2: Load and SW Market Impacts to LOLP (121 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	22.1	24.2	26.2
Med Load	7.8	9.9	12.0
Low Load	1.9	3.7	5.6

Sensitivity Analysis

Sensitivity analyses are useful in helping to understand how results may change as particular input assumptions vary. We have already seen, in the section above, how LOLP changes as economic load growth and SW market assumptions vary. In this section, the sensitivity of LOLP to additional demand response and to a loss of gas supply is investigated.

Tables 3 and 4 show how LOLP changes as more demand response is added to the power supply.[8] Studies run to produce the results in these tables are identical to those run to produce the results in Table 2, with the exception that more demand response was added to each. In Table 3, an additional 379 megawatts of demand response was added to all the studies (for a total of 500 megawatts of new demand response). In Table 4 an additional 1,136 megawatts (or a total of 1,257 megawatts) of new demand response was added. As evident in the results summarized in these tables, demand response can be a very effective resource toward maintaining an adequate supply. Studies using the Council's Regional Portfolio Model, during the development of the Seventh Power Plan, indicated that up to about 1,300 megawatts of new demand response resource could be cost effective relative to other options to maintain adequacy. Unfortunately, the infrastructure and experience needed to acquire that much new demand response is not as well developed as for energy efficiency programs, thus there remains uncertainty whether this level of new demand response would actually be implementable by 2021. The Council has encouraged utilities to continue to investigate and develop means to more easily acquire cost-effective demand response resources both for winter and summer needs.

[8] It should be emphasized that demand response is exclusively a capacity provider with very limited energy contributions. As such, it may not be the best solution to offset longer-term curtailments (e.g. those that last over the 16 peak load hours of the day).

Table 3: Load and SW Market Uncertainty LOLP Map Existing (500 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	15.9	18.5	20.4
Med Load	5.5	7.7	9.5
Low Load	1.4	3.0	5.0

Table 4: Load and SW Market Uncertainty LOLP Map Existing (1,257 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	7.6	10.0	12.5
Med Load	2.6	4.7	6.7
Low Load	0.4	1.9	3.5

Table 5: Sensitivity – Loss of Gas Supply/Market Friction
(Loss of 650 MW IPP Resource)

Import	Base Case	IPP Loss + 121 MW DR	IPP Loss + 500 MW DR	IPP Loss + 1257 MW DR
High Load	24.2	30.0	23.1	13.3
Med Load	9.9	13.2	9.6	6.1
Low Load	3.7	5.4	4.5	2.9

Table 5 summarizes the sensitivity of LOLP to a loss of Northwest market supply due to a shortage of fuel (gas). The Northwest has about 3,000 megawatts (nameplate) of independent power producer (IPP) generating capability. Council adequacy assessments assume that all of that capability is available for Northwest use during winter months but only 1,000 megawatts is available during summer months (due to competition with SW utilities). These sensitivity studies examined how much the LOLP increases due to a loss of 650 megawatts of IPP generation during winter and about a 220 megawatt loss of IPP generation during summer.

As is evident in that table, a loss of Northwest market has a similar effect on LOLP (making it bigger) as does the loss of SW market supply. This type of analysis could also be thought of as a surrogate for a “market friction” sensitivity analysis. Market friction is commonly thought of as a decrease in market access due to transmission limitations or due to more conservative operations by utilities during periods of short supply (e.g. utilities may hold more generating capability in reserve during certain conditions) or a combination of both. This type of analysis will be important to investigate further for future adequacy assessments.

Monthly Analysis

Currently, the Council's adequacy standard sets a 5 percent maximum threshold for annual loss of load probability. This standard has been very useful in the past, especially compared to older deterministic methods, to aid the region in maintaining an adequate power supply. However, with the addition of more and more variable energy generation resources, such as wind and solar, and with the anticipated large increase in solar rooftop development, an annual metric may no longer be the best measure for adequacy. Figure 1 below shows the monthly LOLP values for both the reference case and the case with Colstrip 1 and 2 also retired. It is clear from this figure that the region has both winter and summer adequacy issues. For the reference case, the highest monthly LOLP values still appear mostly in winter but when the two Colstrip plants are also removed, the late summer LOLP value exceeds the winter month values.

It is important to differentiate by month (or at least by season) in order to find optimum resource acquisition strategies. For example, some demand response programs are only available in winter or in summer. It should be noted that the sum of monthly LOLP values will not equal the annual value because the annual value 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 for the annual LOLP value as a simulation with only a January event or only an August event. Monthly values for other adequacy metrics are summarized in that section of this report.

Figure 1: LOLP by Month

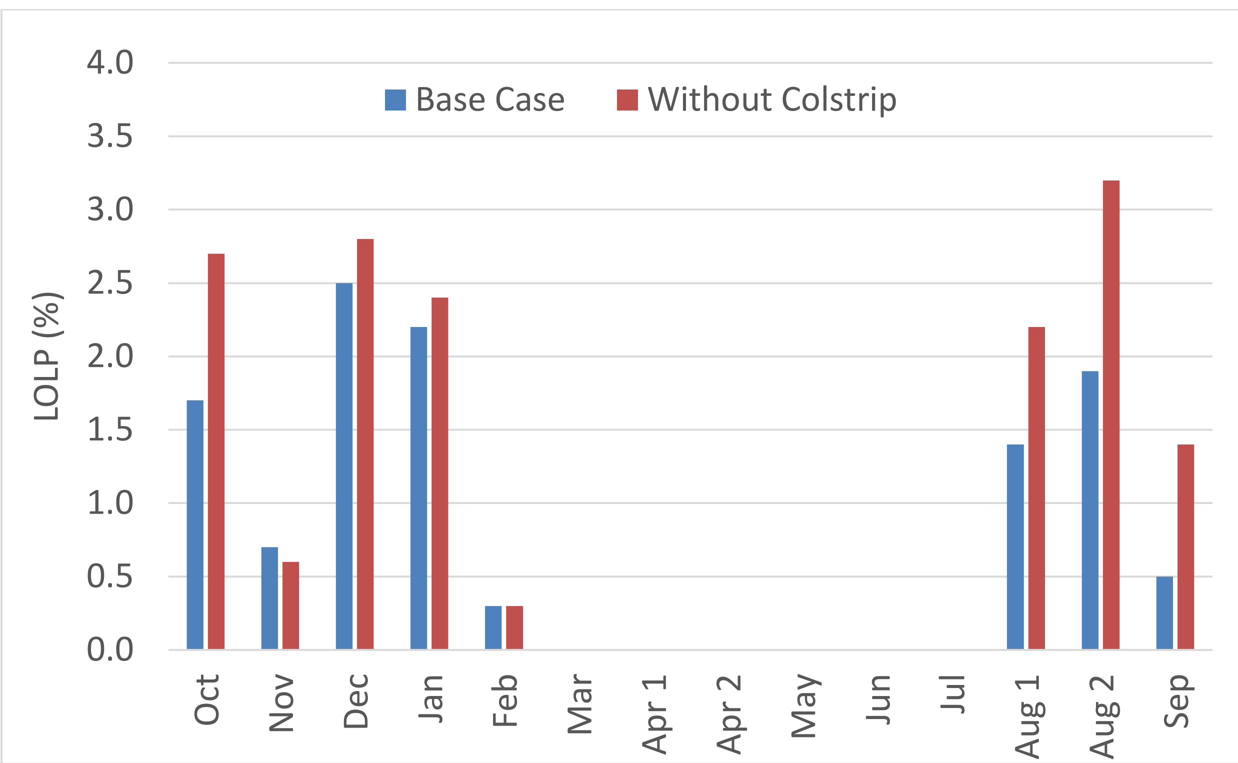

Table 6 summarizes the average monthly dispatch for groups of resources, namely wind, coal, gas, nuclear and SW market. This table shows the monthly dispatch for the reference case and for the case with the Colstrip 1 and 2 coal plant retirement and the difference. With the added loss of Colstrip 1 and 2, as expected, gas generation and SW market purchases go up to cover, as best they can, the loss of the coal generating capability. Obviously, the shift in the dispatch for these resources is not sufficient to offset the loss of the Colstrip plants as evident in the increase in curtailment events and the increase in the LOLP.

Table 6: Expected Resource Dispatch for 2021[9]

2021 Base Case	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	1203	1248	1201	1312	1296	1560	1767	1862	1751	1704	1571	1454	1342	1150
Coal	3254	2754	2861	2225	1828	1484	1557	801	467	670	1784	2862	3259	3533
Gas	2710	1184	1310	1356	1043	752	776	563	494	560	847	1596	2048	2439
Nuclear	1034	1039	1070	1075	1128	1076	1071	1066	1076	1053	1077	1067	1110	1055
SW Market	487	505	603	593	343	174	211	55	9	24	88	249	338	403

2021 No Colstrip	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	1203	1248	1201	1312	1296	1560	1767	1862	1751	1704	1571	1454	1342	1150
Coal	3027	2561	2672	2054	1718	1410	1474	777	466	649	1679	2700	2986	3224
Gas	2895	1271	1409	1425	1093	785	819	574	495	571	898	1711	2197	2625
Nuclear	1034	1039	1070	1075	1128	1076	1071	1066	1076	1053	1077	1067	1110	1055
SW Market	524	569	674	648	383	202	240	64	10	28	99	277	375	440

No Colstrip - Base	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	-227	-193	-189	-171	-110	-74	-83	-24	-1	-21	-105	-162	-273	-309
Gas	185	87	99	69	50	33	43	11	1	11	51	115	149	186
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW Market	37	64	71	55	40	28	29	9	1	4	11	28	37	37

Curtailment Statistics

[9] These studies for the 2021 operating year included no maintenance for the region's sole nuclear plant, which is in error. The 2-year maintenance schedule for the Columbia Generating Station has that plant out of service for about a 2 month period during odd years. So, these studies should have shown zero capability for nuclear during May and June. Since no curtailments are expected during these months, even with the shutdown of the nuclear plant, the resulting LOLP values would remain unchanged.

Sometimes, simply looking at simulation results can provide insight into the behavior of the power system. Table 7 below summarizes a few statistics for the curtailment events reported in our analysis. All adequacy studies were run with 6,160 simulations.

Besides looking at curtailment statistics, it may also be of great use to examine what conditions existed during the time of each shortfall. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis will be provided in a separate spreadsheet (available on the Council's website). The four random variables displayed in the spreadsheet are;

- Water supply, as a percentage of monthly runoff volume
- Temperature, as a percentage of that day's historical temperature range
- Wind generation, based on historical wind capacity factors from BPA's wind fleet
- Forced outage conditions

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.

Table 7: 2021 Simulated Curtailment Statistics

Statistic		**Units**
Number of simulations	6,160	Number
Simulations with a curtailment	610	Number
Loss of load probability (LOLP)	10	Percent
Number of curtailment events	2,374	Number
Number of events per year	0.4	Events/year
Average event duration	11	Hours
Average event magnitude	12,700	MW-hours
Average event peak curtailment	1,200	MW
Expected curtailed hours per year (LOLH)	2.4	Hours
Expected un-served energy (EUE)	2,500	MW-hours
Events with duration of 1 to 2 hours	11	Percent
Duration of 1 to 4 hours	20	Percent
Duration of 1 to 6 hours	28	Percent
Duration of 1 to 12 hours	49	Percent
Duration of 1 to 14 hours	56	Percent
Duration of 1 to 16 hours	86	Percent
Duration greater than 16 hours	14	Percent
Highest likely duration (15 to 16 hours)	30	Percent

Figure 2 can be used to examine the likelihood for particular duration curtailment events. In that figure, the y-axis represents the duration for an event and the x-axis represents the probability of an event with that duration (or greater) of occurring. For example, in Figure 2 the 50th percentile duration (median value) is about 13 hours.[10] This means that we expect a 50 percent chance of observing a curtailment event of 13 hours or more.

Figure 2: Curtailment Event Duration Probability

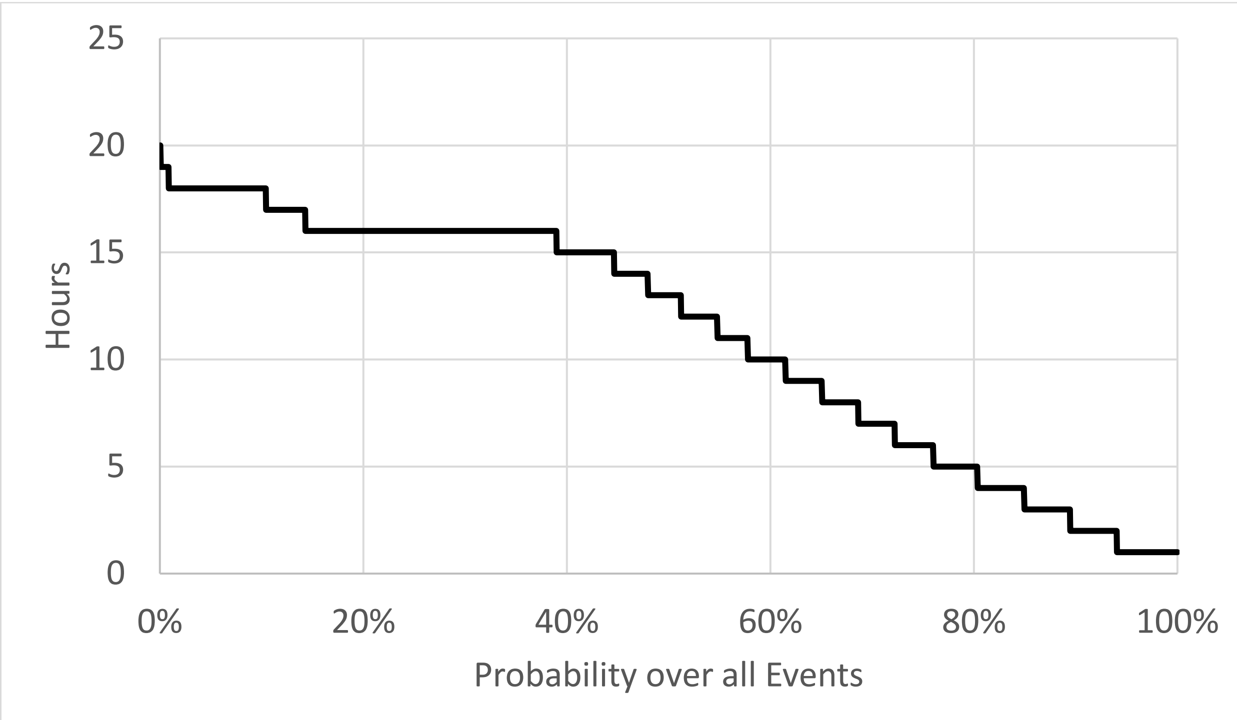

Figure 3 shows the same information in a different way. In that figure, the y-axis represents the percent of times that an event of particular duration occurs in the study. This is commonly referred to as a frequency distribution chart. For example, the most likely duration for an event is 16 hours. From Figure 3 a 16-hour duration event has about a 25 percent chance of occurring. The second most likely duration for an event is 18 hours. This result is not surprising since GENESYS will attempt to uniform any shortfall it sees across all the high-load hours of the day. Figure 4 shows the same information but the curtailment durations have been combined into 2-hour bins (as opposed to single hour bins in Figure 3). Figure 4 simply highlights the result that most event durations are between 15 and 18 hours. And, finally, Figure 5 provides more of a cumulative probability for event duration.

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[10] Note that the median duration is 13 hours while the average duration is 11 hours. This is because the distribution of event durations is not symmetric.

Figure 3: Event Duration Frequency (1-hour block incremental)

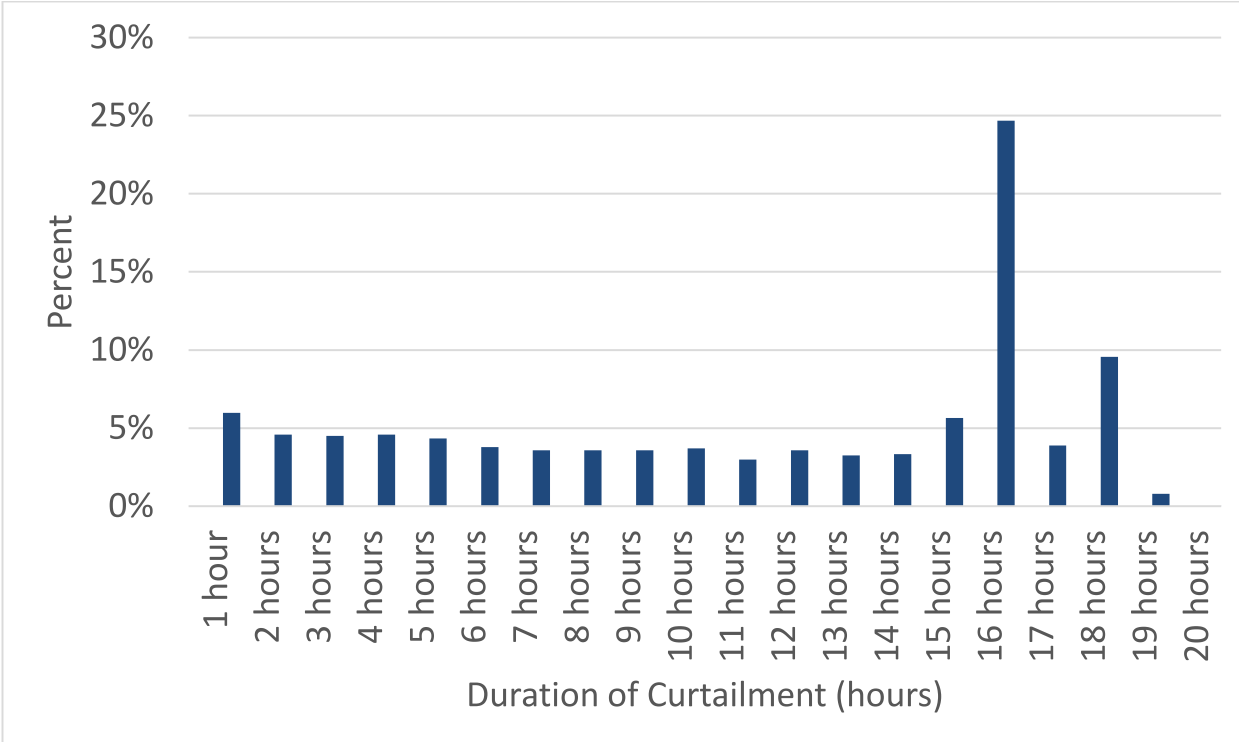


Figure 4: Event Duration Frequency (2-hour block incremental)

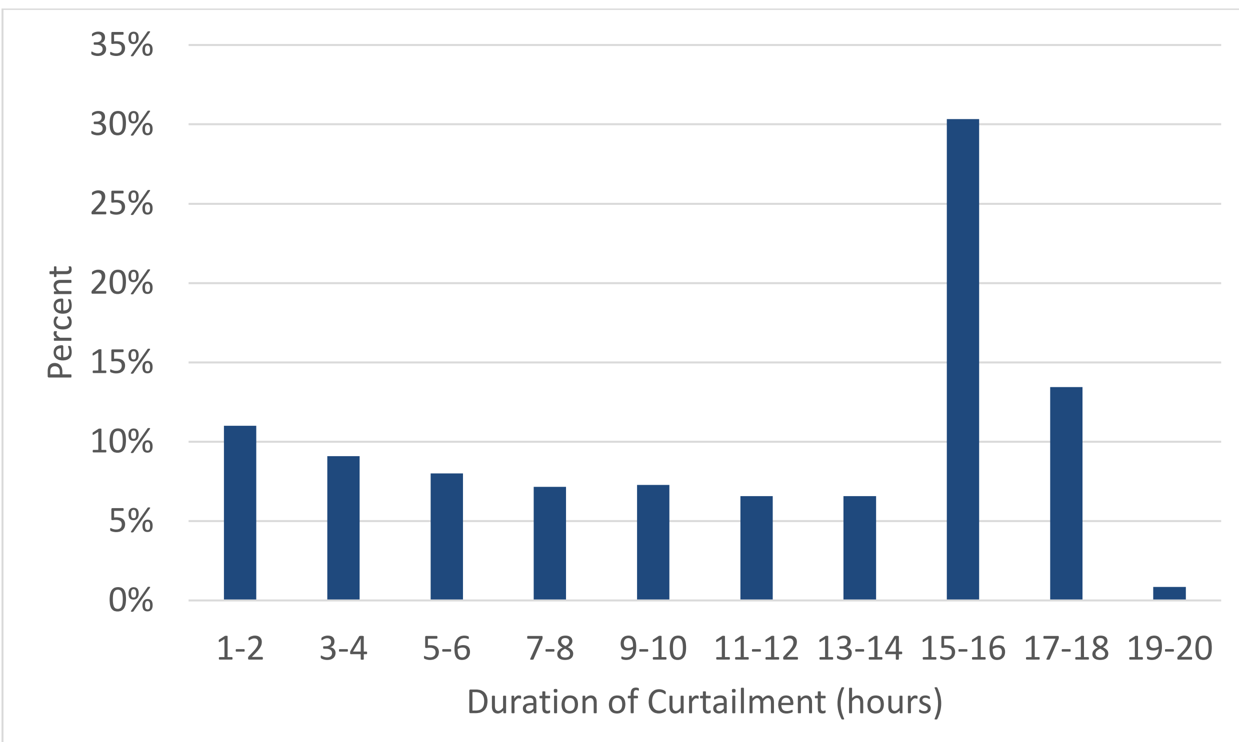
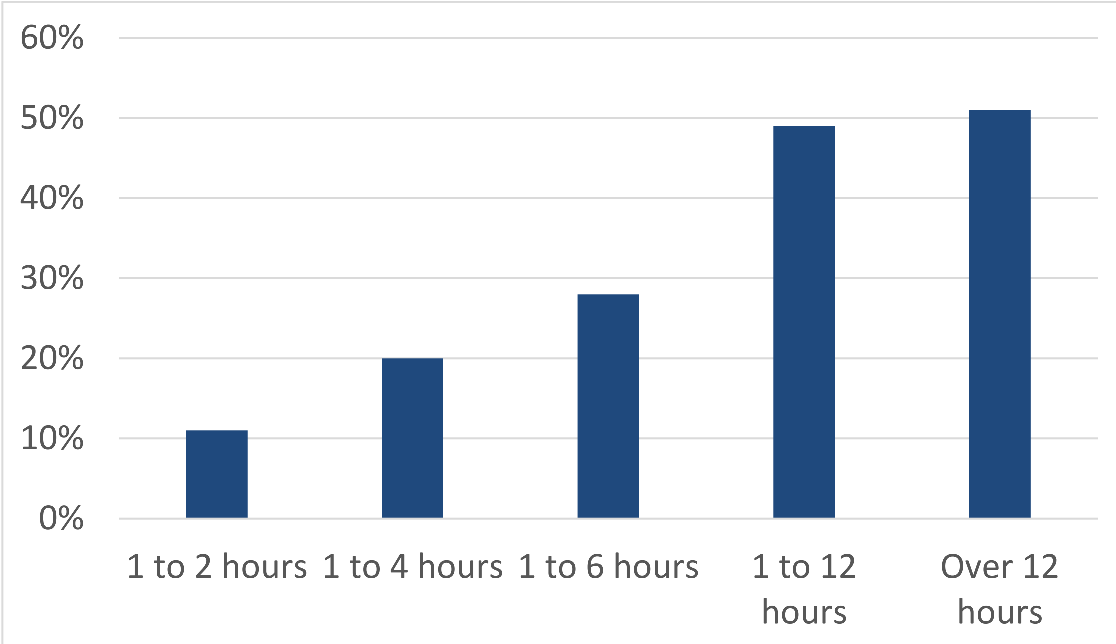


Figure 5: Event Duration Frequency (various time blocks)



The point at which these curves cross the horizontal axis would represent the LOLP except that these data were plotted prior to the implementation of standby resources.[11] By applying the effects of standby resources to the reference case results, the LOLP drops from a little over 13 percent down to the final value of 9.9 percent. In other words, if we could modify the curtailment record for that case to shows the effects of standby resources, the resulting probability curve would shift down and cross the horizontal axis at 9.9 percent. Doing the same for the Colstrip retirement case drops the LOLP to a little over 13 percent.

Figure 6 displays the <u>annual</u> unserved energy probability over all games for both the reference case and the Colstrip retirement case. The total unserved energy for each of the 6,160 games is summed up and then sorted from highest to lowest. Those results are then graphed in Figure 6. The vertical axis represents the amount of annual unserved energy and the horizontal axis represents the likelihood of observing a particular amount of annual unserved energy or more. From Figure 6, without the effects of standby resources, it appears that there is about a 13 percent[12] chance of observing a game with at least one curtailment (this is where the curve in Figure 6 crosses the horizontal axis). The probability curve for the Colstrip retirement case crosses the horizontal axis at about 17.7 percent.

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[11] This is a simplification of the actual process, which takes into account monthly results.

[12] Remember this result is prior to adding the effects of standby resources.

Figure 6: Annual Unserved Energy Probability

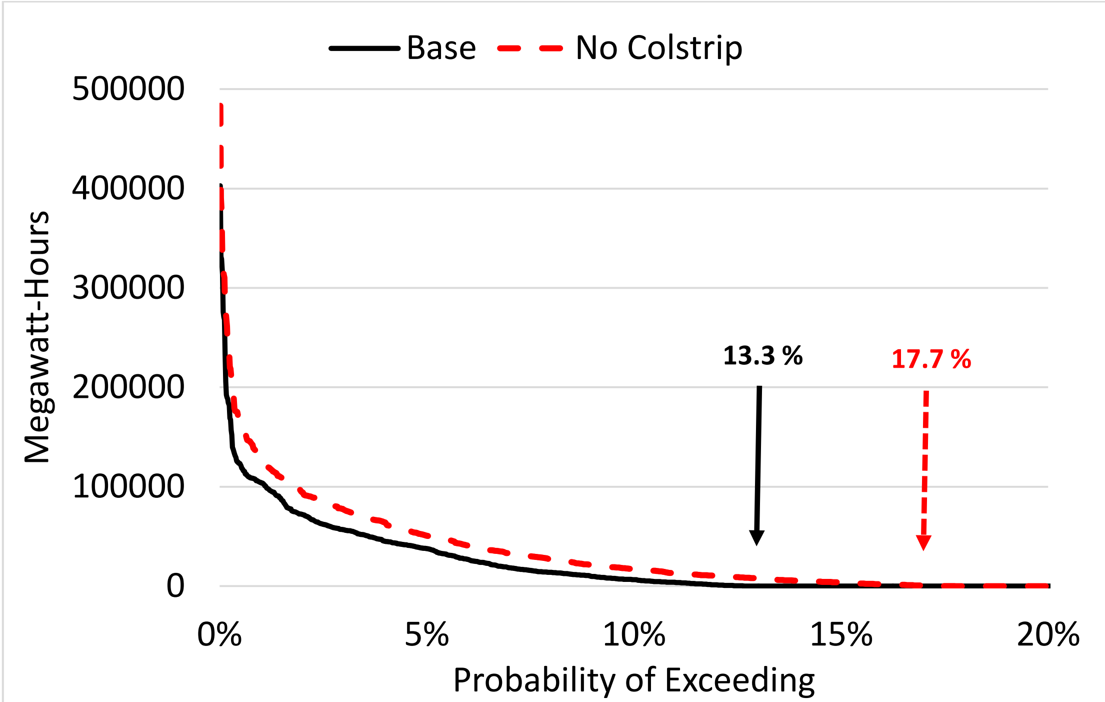


Figure 7a displays the worst-hour unserved energy probability for all games for both the reference case and the Colstrip retirement case. This figure is similar to Figure 6 but plots the worst (highest) single-hour unserved energy for each game, instead of the annual unserved energy. As expected, the probability curves in this figure cross the horizontal axis at the same percentage values as the curves in the annual unserved energy chart (Figure 6).

The curves in this figure can be used to estimate the amount of additional capacity needed to make the power supply adequate (not including the effects of standby resources). By looking at a blown-up section of Figure 7a, shown in Figure 7b, it becomes easier to see how much new capacity is required to shift the entire curve down so that it crosses the horizontal axis at the 5 percent Council adequacy limit. For the reference case, it requires a little over 1,800 megawatts of new capacity (simply draw a straight line up from the 5 percent point on the horizontal axis to the curve and then draw a straight line to the left to see where it would cross the vertical axis). Recall that these data have not been adjusted for standby resources, which contribute a little over 600 megawatts of capacity in winter. Thus, the estimate for required new capacity – in addition to the standby resource contribution – to maintain adequacy is about 1,200 megawatts. For the Colstrip retirement case, the needed amount of new capacity is about 1,500 megawatts. These values, however, are only estimates because they lump the curtailment events from all months together. Results from the more accurate analytical approach (which also include the effects of standby resources) show a need of about 1,040 megawatts and 1,400 megawatts of new capacity to maintain adequacy for the reference case and Colstrip retirement case, respectively.

It should be noted that it requires both new capacity and energy additions to move the 2021 LOLP down to the Council's 5 percent standard. Analysis indicates that the greatest need for the 2021 supply is addition of capacity, however, simply adding capacity with no energy will not result in an adequate supply. Each new resource has at least some energy providing capability, some more than others. For example, demand response programs can provide a lot of capacity but cannot be dispatched for long periods of time and therefore, provide only a very limited amount of energy. Wind resources, on the other hand, can provide a great deal of energy but can only be counted on to provide about 5 percent of their nameplate capacity toward peaking needs. This is why the Council uses its Regional Portfolio Model, which knows the energy and capacity contributions of all new resources, to develop a resource strategy that will lead to an adequate supply.

Figure 7a: Worst-Hour Unserved Energy Probability

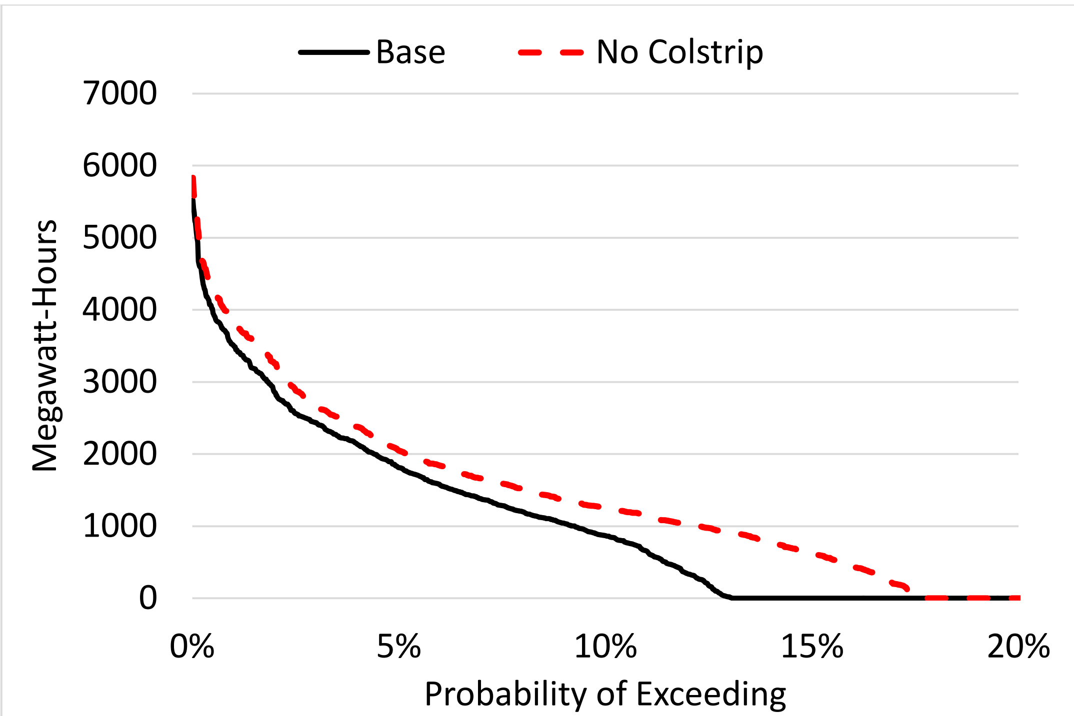
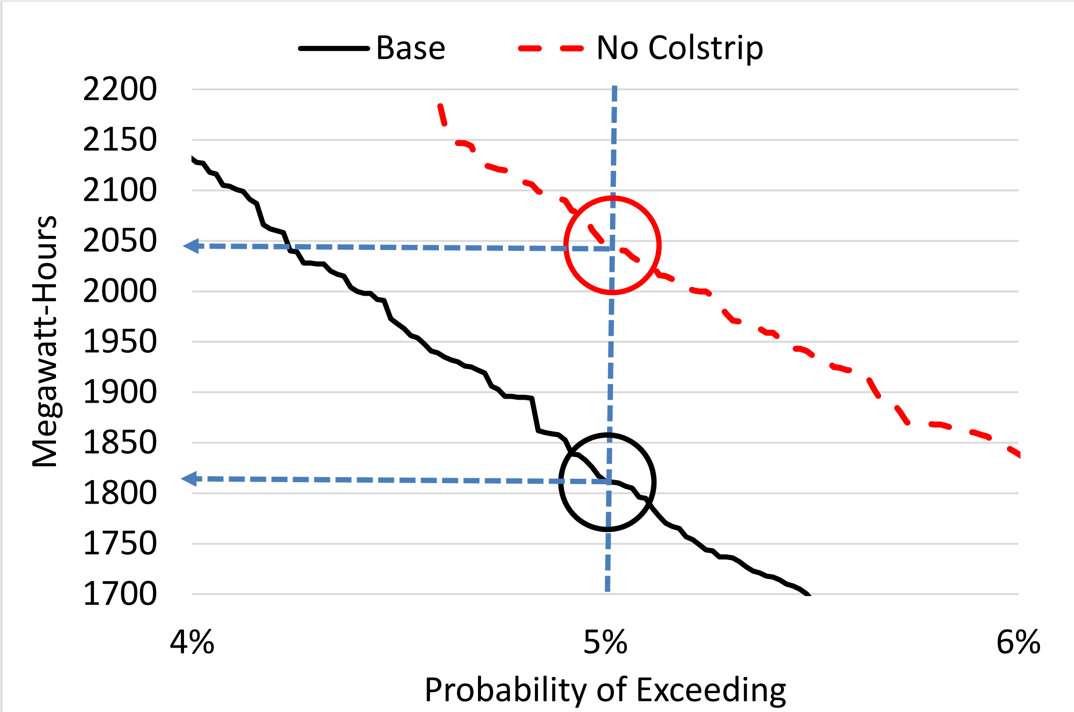


Figure 7b: Worst-Hour Unserved Energy Probability (Blow Up)



Other Adequacy Metrics

Other adequacy metrics help planners better understand the magnitude, frequency and duration of curtailments. These other metrics provide valuable information to planners as they consider resource expansion strategies. Table 8 below defines some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 9 provides the regional assessments of these metrics for 2017, 2019, 2020 and 2021.

While the Council has been using an annual LOLP metric to assess adequacy for nearly a decade, it became evident during the development of the Seventh Power Plan that monthly (or at least quarterly) values are essential to ensure a truly adequate supply. This is because resources can provide different energy and capacity contributions over each quarter. Also, the characteristics of potential shortfalls can vary by season. Thus, the Council's Regional Portfolio Model required quarterly adequacy reserve margins to develop more cost effective resource expansion strategies. The calculation of quarterly adequacy reserve margins requires quarterly adequacy targets. Recognizing this, the Council added an action item to reevaluate and amend its existing adequacy standard. Table 10 provides monthly values for LOLP and other adequacy metrics.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It asked that each sub-region 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 assessed across the United States but it falls far short of establishing adequacy thresholds for these metrics. It may, in fact, be impossible to set thresholds because power supplies can vary so drastically across regions.

Table 8: 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 (MW-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
LOLH (Hours)	Loss of load hours = total number of hours of curtailment divided by total number of games
PGC (%)	Percent of games with curtailment prior to implementing standby resources

Table 9: Annual Adequacy Metrics (Base Case)

Metric	2017	2019	2020	2021	Units
LOLP	6.6	5.9	4.7	9.9	Percent
CVaR - Energy	99,000	59,200	50,589	46,378	MW-hours
CVaR - Peak	4,000	3,337	2,949	2,185	MW
EUE	5,000	3,000	2,536	2,482	MW-hours
LOLH	2.7	1.7	1.5	2.4	Hours/year
PGC	9.7	8.3	6.4	13.6	Percent

Table 10: Monthly Adequacy Metrics (Base Case)

Month	LOLP Peak %	LOLP Energy %	Overall LOLP %	EUE MW-Hours	LOLH Hours
Annual	**9.9**	**1.8**	**9.9**	**2,482**	**2.4**
Oct	1.7	0.3	1.7	240	0.5
Nov	0.7	0.1	0.7	170	0.1
Dec	2.5	0.5	2.5	768	0.6
Jan	2.2	0.6	2.2	930	0.6
Feb	0.3	0.2	0.3	105	0.1
Jul	0	0	0	1	0
Au1	1.4	0.2	1.4	102	0.2
Au2	1.9	0.4	2	146	0.3
Sep	0.5	0.1	0.6	21	0.1

Assumptions

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on non-utility supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,943 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.

Other assumptions used for the 2021 adequacy assessment are shown in Table 11 through Table 15. Table 11 summarizes assumptions for load, energy efficiency savings and out-of-region market availability. Tables 12 and 13 provide the energy and capacity contributions for standby resources. Tables 14 and 15 provide the monthly incremental and decremental balancing reserves that were assumed. To the extent possible, the hydroelectric system was used to carry these reserves. Using the Council's hourly hydroelectric optimization program (TRAP model), a portion of the peaking capability and minimum generation at specific hydroelectric projects was reserved to support the within-hour balancing needs. Unfortunately, not all balancing reserves could be assigned to the hydroelectric system. The remaining reserves should be assigned to other resources but the current adequacy model does not have that capability. This is one of the major enhancements targeted in the GENESYS redevelopment process.

Table 11: Assumptions used for the 2021 Adequacy Assessment

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Mean Load (aMW)	21,234	20,975	18,813	19,987
Peak Load (MW)	33,768	33,848	26,504	28,302
DSI Load (aMW)	338	338	338	338
Mean EE (aMW)	1,545	1,574	1,274	1,208
Peak EE (MW)	2,660	2,660	1,680	1,680
Spot Imports (MW)	2,500	2,500	0	0
Purchase Ahead (MW)	3,000	3,000	3,000	3,000

Table 12: Standby Resource Assumptions – Peak (MW)

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Exist DR	220	220	781	781
Exist Emergency Gen	266	266	266	266
Total Existing	**486**	**486**	**1047**	**1047**
Planned DR	121	121	0	0
Total Exist + Planned	**607**	**607**	**1047**	**1047**
Min DR (from the RPM)	379	379	468	468[13]
Total Exist + Plan + Min	**986**	**986**	**1515**	**1515**
Expected DR (from RPM)	1,136	1,136	1,178	1,178
Total Exist + Plan + Expect	**1,743**	**1,743**	**2,225**	**2,225**

[13] These are existing summer demand response programs.

Table 13: Standby Resource Assumptions – Energy (MW-hours)

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Exist DR	37,250	37,250	69,542	69,542
Exist Emergency Gen	5,800	5,800	5,800	5,800
Total Existing	**43,050**	**43,050**	**75,342**	**75,342**
Planned DR	6,050	6,050	0	0
Total Exist + Planned	**49,100**	**49,100**	**75,342**	**75,342**
Min DR (from the RPM)	18,950	18,950	23,400	23,400
Total Exist + Plan + Min	**68,050**	**68,050**	**98,742**	**98,742**
Expected DR (from RPM)	56,800	56,800	58,900	58,900
Total Exist + Plan + Expect	**105,900**	**105,900**	**134,242**	**134,242**

Table 14: Within-hour Balancing Reserves – Incremental (MW)

Period	BPA Hydro	Non-BPA Hydro	Non-BPA Thermal[14]
October	900	584	562
November	900	748	711
December	900	782	768
January	900	929	816
February	900	763	702
March	900	797	738
April 1-15	400	719	672
April 16-30	400	719	672
May	400	912	910
June	400	810	799
July	900[15]	750	958
August 1-15	900	797	640
August 16-31	900	797	640
September	900	716	662

[14] These balancing reserves were not assigned for this analysis.

[15] BPA's DEC reserve requirements of 400 megawatts extend through the end of July but the analysis in this report incorrectly assumed that the July reserve requirement was 900 megawatts. It was determined that rerunning all of the studies to include this correction was not warranted.

Table 15: Within-hour Balancing Reserves – Decremental (MW)

Period	BPA Hydro	Non-BPA Hydro	Non-BPA Thermal
October	900	662	786
November	900	899	1,264
December	900	687	1,073
January	900	751	908
February	900	728	955
March	900	690	899
April 1-15	900	713	942
April 16-30	900	713	942
May	900	748	1,044
June	900	723	898
July	900	629	811
August 1-15	900	609	872
August 16-31	900	609	872
September	900	746	910

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply. This task is becoming more challenging because planners must now focus on satisfying not only winter energy needs but also summer energy needs and capacity needs year round. Continued development of variable generation resources, combined with changing patterns of electricity demand have added complexity to the task of successfully maintaining an adequate power supply. 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 reflect real life operations and to address capacity issues.

Another emerging concern is the lack of access to supplies for some utilities due to insufficient transmission or due to other factors. For the current adequacy assessment, the Northwest region is split into two subsections[16] in which only the major east-to-west transmission lines are modeled. Similarly, only the major Canadian-U.S. and Northwest-to-Southwest interties are modeled. The Council is hoping to address these issues in future adequacy assessments.

Also, at some point, uncertainties surrounding the change in Canadian flood control operations in 2024 and the effects of a potentially renegotiated Columbia River Treaty will have to be addressed. But besides these issues, the Council's latest 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 2016 by the Council's Resource Adequacy Advisory Committee to consider for next year's assessment include those listed below:

Rec-1	Review methodology of the hybrid load forecast used for the 2021 adequacy assessment, in particular how peak loads are forecast
Rec-2	Provide an hourly forecast for energy efficiency savings.
Rec-3	Investigate how to incorporate uncertainty in EE savings into the adequacy assessments

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

Rec-4 Investigate availability of regional and extra-regional market supplies during periods of stress (supply shortages)

Rec-5 Investigate the availability of fuel during periods of stress, especially for resources without firm fuel contracts.

Rec-6 Investigate the availability of the interties that connect the NW with regions that may provide market supplies. Consider adding maintenance schedules and forced outages.

Rec-7 Explore ways to incorporate the effects of climate change into the adequacy assessments. Should assessments only include the effects of recent temperature years or is there a way to adjust historic temperature profiles to account for climate change?

Rec-8 Explore how an energy imbalance market might affect adequacy assessments. Investigate ways to incorporate an EIM into the analysis.

Rec-9 Review the use of standby resources in the adequacy assessments, in particular how demand response is modeled. The algorithms in the standby resource post processor should be incorporated into the GENESYS model. DR should be dispatched based on price. How do we deal with existing DR, assuming that its impacts have been captured (somewhat) in the load forecast?

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 May of 2017. However, any enhancements that can be made and tested in time for the next assessment will be implemented. Thus, it continues to be important to isolate the effects of modeling changes on the LOLP from the effects of changes in loads and resources.

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