The Year 2030 Extreme Natural Event Study Report

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Executive Summary

The bulk power system (BPS) in the Western Interconnection has recently experienced challenges due to extreme weather events becoming more frequent and more severe. Further, the changing resource mix with higher renewable penetration adds more variability to the system. Various factors such as climate change have emphasized the need to study these extreme events, which can occur simultaneously (such as extreme heat and wildfires) causing widespread effects on the Bulk Power System (BPS).

An extreme natural event in the context of this study is considered multiple, low-probability, widespread weather events occurring simultaneously within a limited period with the potential of having a very large impact on the reliability of the BPS. The purpose of this assessment is to identify some of the key reliability risks associated with multiple extreme events happening simultaneously in the 10-year future, along with expected changes in the resource mix. For this assessment, the reliability metrics explored were system voltage and frequency response, unserved energy, ancillary service deficiencies, and WECC Path utilization.

The assessment assumed that these events would occur during the same two-week period in the 10-year future. The following assumptions were made regarding the extreme natural event studied:

1. Heat wave: A heat wave was modeled in this assessment by increasing the demand that can result from increased temperatures. Three load profiles were selected to study the increased loads:
    - Loads based on the August 2020 heat wave using WECC's year 2030 probability forecast;
    - A 1-in-10-year load profile; and
    - A 1-in -20-year load profile.
2. Wildfire: The assessment assumed that the smoke coverage from the wildfire would reduce solar output. This was based on the September 2020 wildfires in which the Western Interconnection diverged from the forecast solar output levels due to smoke coverage of solar panels, attributed to the extensive wildfires.
3. Drought: Drought conditions affect reservoir levels used to serve hydro-electric dams. The Northwest region, especially, depends heavily on hydroelectric power, which provides about half of the region's annual energy generation [1]. The drought conditions were modeled by reducing hydroelectric availability in the Northwest by 30%.
4. To further emulate the impacts of these extreme conditions and stress the system, seven sustained transmission outages were included in the models. Three frequent transmission outages were also studied by analyzing historic outage data available through the Transmission Availability Data System (TADS).

The starting cases used in the study were the 2030 Anchor Data Set (ADS) Production Cost Model (PCM) and the 2030 Heavy Summer (HS) power flow (PF). In these cases, an additional 3 GW of coal generation in the Montana and Colorado regions was identified to be scheduled to retire before 2030 and assumed to be unavailable in the assessment. These cases were modified as follows for the above assumptions to create cases to study:

1. In the PCM, three separate cases were modeled for each load profile to which solar and hydro reductions and coal retirements were applied. To each of these cases, seven sustained transmission outages were applied to create three more cases to determine the effect of outages on BPS during the extreme natural event.
2. In the PF, the 2030 HS PF was adjusted to match the ratios of load and generation that existed in the hour with the highest load on August 15, hour 17, in the PCM case with load profiles based on the August 2020 heat wave. Solar, coal, and hydro generation capacity reductions were then applied to the extreme natural event case. The largest N-2 contingency was applied to the case to see the impact on frequency response. Additionally, seven sustained transmission outages were applied to the case to determine the effect of outages on the BPS during the extreme natural event.

The analysis of the PF cases resulted in the following observations:

- No frequency delved below the standard underfrequency load shedding (UFLS) thresholds, and the system remained stable.
- Voltage oscillations were identified in all simulations. The addition of transmission outages made the oscillations more pronounced. No instabilities were observed in any of the simulations.

The analysis of the PCM cases resulted in the following observations:

- Many regions experienced unserved energy, especially during shoulder hours when solar production was ramping down. Unserved load was minimal for the loads modeled in the 2030 ADS PCM case but was more extreme when loads reach the 1-in-10 or 1-in-20 probability models.
- Inter-regional transfers were lower compared to 2030 ADS PCM (for the studied two-week period) and regions dependent on imports in the cases studied from neighboring regions had much less energy imported.
- Many regions did not meet the ancillary service requirements for much higher number of hours as compared to 2030 ADS PCM for the modeled two-week period for spinning reserves, regulation up and down, and load-following up and down.
- Interregional transmission flows changed and increased some WECC Path flows to near their ratings for much higher durations compared to 2030 ADS PCM.
- The seven sustained transmission outages evaluated in this assessment did not significantly affect unserved load, ancillary service deficiencies, or path utilization in and of themselves, otherwise experienced during the extreme natural event.

The following recommendations are offered based on observations in this assessment:

- Planning entities should consider mitigation of unserved energy during extreme events as part of planning studies and should evaluate impacts to load and generation.
- Planning and operating entities should consider further analysis of reserves and ramping requirements to withstand extreme events.
- Planning and operating entities should consider extreme events when performing in-depth studies of transmission congestion.
- Transmission planners should consider simulating compounded extreme weather events, such as drought and heat wave, simultaneously in planning studies and monitor system voltage performance.
- WECC's Reliability Assessment Committee (RAC) should discuss and coordinate the development of a guidelines for using appropriate extreme natural event assumptions and data for the Western Interconnection for reliability assessments.

Table of Contents

Purpose

Western North America is experiencing significant transitions on two fronts:

1. Climate change and extreme weather events are growing more frequent and severe; and
2. Variable energy resources (VER) are becoming a larger percentage of resource portfolios.

Historically, disruptive events were infrequent and less extreme, so entities could reliably plan for and accept the risks of those events and the disruptions they caused. However, the combination of climate change and growing numbers of variable energy resources (VER) has increased the risk of extreme events for the Western Interconnection. Furthermore, while these events have typically occurred one at a time and had localized consequences; now, some events are occurring simultaneously and affecting larger portions of the interconnection. For instance, a widespread heat wave may occur during intense drought and wildfires, similar to conditions in the Pacific Northwest in June 2021 [2]. Or a severe winter storm can occur following drought conditions, e.g., the Boulder County, Colorado, event in December 2021 when a severe winter storm followed extreme drought and wildfires fanned by high winds [3]. Extreme disruptive events are no longer isolated and no longer occur at low frequencies. For the bulk power system (BPS) to withstand and reduce the impacts from current and future disruptive events, planners and operators must understand how the changing weather systems affect the changing power system. This report aims to shed light on the dynamic behavior of the system under stressed conditions.

An extreme natural event in the context of this study is considered multiple, low-probability, widespread weather events occurring simultaneously within a limited period with the potential of having a very large impact on the reliability of the BPS. This assessment investigated how the reliability of the Western BPS would be affected by risks associated with extreme natural events in the 10-year future. Specifically, this assessment seeks to answer the following questions:

- If part of the Western Interconnection experiences an extreme natural event that includes a simultaneous heat wave, drought, and wildfire, can the BPS avoid unserved energy?
- In the extreme natural event modeled in this assessment, can the BPS maintain adequate ancillary services?
- Does the modeled extreme natural event create transmission flows that could lead to reliability risks?
- In this extreme natural event, can the BPS respond to a transmission outage while maintaining voltage and frequency response within limits?
- How would the above reliability risks be realized on the BPS if multiple transmission outages were to occur during the extreme natural event?

Assumptions

For this assessment, several extreme natural events were assumed to be occurring simultaneously during the same two-week period in the 10-year future. The following assumptions were made regarding the extreme events:

1. **Heat wave**: In August of 2020, the Western Interconnection experienced system vulnerabilities and load loss due to high demand attributed to the increased temperatures. For this assessment, three load profiles were modeled to emulate the heat wave:
   - The loads based on the August 2020 heat wave, projected to year 2030, using WECC's probability forecast for August 10–23, 2030;
   - A 1-in-10-year load profile for August 22–September 5, 2030; and
   - A 1-in-20-year load profile for August 22–September 5, 2030.
2. **Wildfire**: The assessment assumed that smoke from the wildfire would reduce solar output. This was based on the September 2020 wildfires in which the Western Interconnection diverged from the forecast solar output levels due to smoke from extensive wildfires blocking sunlight to solar panels. Percentage reduction in solar generation was calculated for the study based on solar values forecast for 2030 by WECC for the month of September and the historical actual values for September 2020. The calculated percentage reduction in solar output was applied to the studied period.
3. **Drought conditions**: Drought conditions affect reservoir levels used to serve hydro-electric dams. The assessment modeled drought conditions by reducing hydroelectric availability in the Northwest by 30%.
4. To further emulate the impacts of these extreme conditions and stress the system, several transmission outages were also included. These outages were identified by analyzing historic outage data available through the Transmission Availability Data System (TADS).
5. The starting cases used in the study were the 2030 Anchor Data Set (ADS) Production Cost Model (PCM) and the 2030 Heavy Summer power flow (2030 HS PF) case. In these cases, 3 GW of coal generation in the Montana and Colorado regions are scheduled to retire by 2030. This generation was assumed to be unavailable in the modeled cases for this assessment.

Development of Input Data

The input data were used to model three separate but related events occurring simultaneously in the West during the summer of 2030: heat wave, wildfire, and drought.

Heat Wave Load Profile Based on August 2020 Heat Wave

This load profile was generated by comparing actual August 2020 heat wave data for the two-week period of August 10–23, 2020, around the heat wave to WECC's probability forecasts for August 2020.

Next, the extrapolated probability percentiles for each hour were used to pull their equivalent values for 2030, which included an increase of 5% to offset the impacts of load shedding and demand management. During the August 2020 heat wave event, several Balancing Authorities (BA) implemented procedures that resulted in lower actual load values that would otherwise have occurred if such a procedure had not been necessary.

1-in-10 Load Profiles and 1-in-20 Load Profiles[1]

To further analyze system performance with increased loads, demand shapes were created with 1-in-10 and 1-in-20 load probabilities. The terminology of 1-in-10 and 1-in-20 loads refers to the probability that loads reach that high level once in 10 years and the more severe case occurs once in 20 years.

Load assumptions from California Energy Demand Forecast Update (CEDU) 2020-2030[2], which is part of the California Energy Commission (CEC) 2020 Integrated Energy Policy Report (IEPR), were used to create 1-in-10 and 1-in-20 heat wave load projections for the 2030 time frame. This forecast includes a single net peak value for each area in California for 1-in-2, 1-in-10, and 1-in-20 projected demand through 2031. The peak loads modeled in 2030 ADS PCM cases were average loads (i.e., 1-in-2 heat wave loads) with a system peak occurring on August 29, 2021. For areas within California, using the CEDU 2020-2030 forecast, a percentage increase in peak for each hour from 1-in-2 to 1-in-10 and 1-in-20 was calculated. These percentages were applied to loads in 2030 ADS PCM case over a two-week period around the system peak occurring on August 29, 2021. For areas outside California, the weighted average of loads in California was derived and used as a proxy for the percentage increase across the rest of the interconnection.

Wildfires and Solar Reduction

The grid in the Western Interconnection is transforming, and the penetration of solar energy is increasing annually. To show this in the 10-year models and to further stress the system, it was considered how wildfires could affect the solar energy. In September 2020, solar output decreased significantly in the Western Interconnection due to several wildfires because the large amount of smoke blocked the solar panels' exposure to the sun.

A percentage reduction in solar generation was calculated for each regional (BA) or a sub-region within a BA by comparing September 2020 historic generation values to the 50th percentile of WECC's probability forecast for solar generation for September 2030. These percentages were used to reduce

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[1] For further details of the development of 1-in-20 and 1-in-10 load profiles, see "Variability in Loads and Resources Assessment 2021" published at WECC Studies Subcommittee website.

[2] California Energy Commission, "CEDU 2020 Baseline Forecast—LSE and BA Tables High Demand Case," published at https://efiling.energy.ca.gov/getdocument.aspx?tn=236526

solar generation both in PCM cases and PF cases for the study period. The appendix includes, in Table 5, the names and abbreviations of the BAs in the Western Interconnection and, in Figure 33, a map of BA boundaries along with their sub-regions. Figure 1 shows the percentage reduction in solar output by BA that was assumed for this assessment.

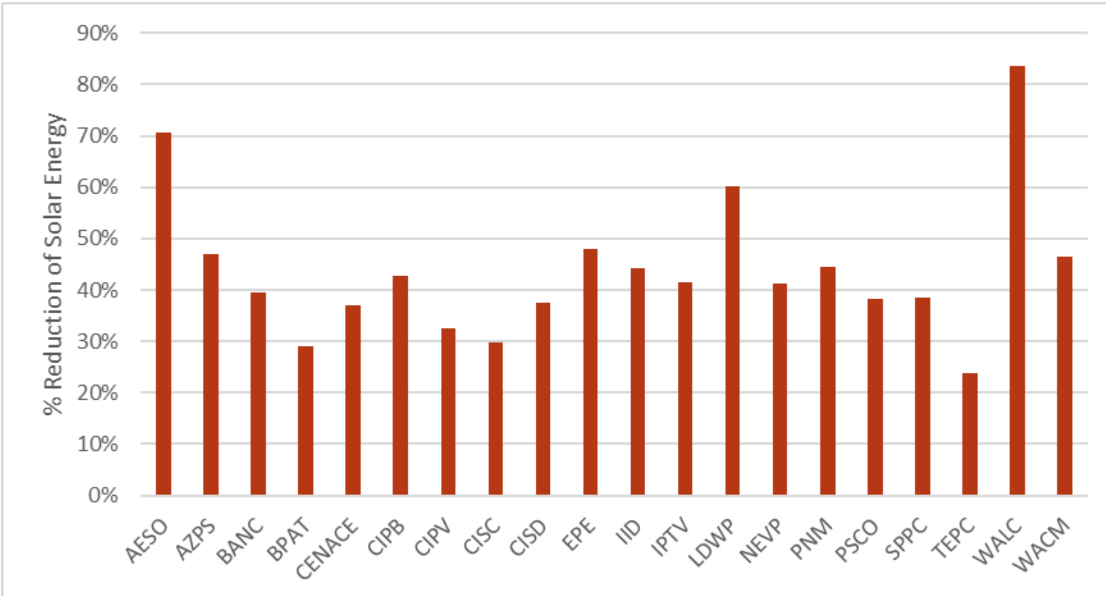


Figure 1: Percentage reduction in solar energy for study assessment

Drought/Hydro Reduction

The third stage of the compounding hot weather event studied was a low hydro condition in the Northwest. The Northwest depends heavily on hydroelectric power—in 2019 around 38.5% of the generation in the Northwest was hydroelectric. The 2030 ADS PCM case used 2009 hydro shapes in the model, which is considered an average hydro year. To simulate low hydro conditions, the lowest average hydro output period was determined from the past 14 years of hydro data from Bonneville Power Administration (BPA). This was found to be May–July 2015. Average hydro generation from this three-month minimum output period was then compared to 2009 hydro data from BPA to calculate the hydro reduction percentage. Hydro production during this period (May-July, 2015) was, on average, 69.5% of hydro levels in 2009. Based on this, a 30% reduction in hydro output in the Northwest area was modeled for this assessment.

Coal Retirements

In the 2030 Heavy Summer case, about 3 GW of coal generation in the Montana and Colorado regions is scheduled to retire as shown in Table 1. These retirement assumptions came from PacifiCorp's 2019 Integrated Resource Plan (IRP) [4] and the United States Energy Information Administration (U.S. EIA) Form EIA-860 [5]. This generation was turned off in PCM cases and not replaced with other resources.

In the power flow cases, these generators were turned off, and, to maintain load-generation balance, other generators (not including solar and hydro generators) were turned on.

Table 1: List of generators retired for study cases

Generator	Retirement Date	PCM Capacity (MW)	Source of Retirement Date
Colstrip 3	12/31/2027	740	2019 PAC IRP
Colstrip 4	12/31/2027	740	2019 PAC IRP
Craig 3	12/31/2029	448	EIA-860 2020
Hayden 1	12/31/2028	179	EIA-860 2020
Hayden 2	12/31/2027	262	EIA-860 2020
Martin Drake 6	12/31/2022	77	EIA-860 2020
Martin Drake 7	12/31/2022	131	EIA-860 2020
Rawhide 1	12/31/2029	280	EIA-860 2020

Transmission Outages and Contingencies

Historic transmission outage data collected over the past 13 years (2007–2021) in Transmission Availability Data Systems (TADS) was analyzed to identify additional outages to be used for the assessment. The analysis of TADS identified the seven, longest-duration, unplanned outages lasting longer than 24 hours at 345–500 kV level. These outages were assumed to have a high probability of causing sustained outages in the future and are recognized in this report as "seven sustained transmission outages." The transmission lines are situated in various regions throughout the Western Interconnection and include a 345 kV line in Arizona, a 500 kV line in Southern California, a 500 kV line in Northern California, a 345 kV line in Nevada, and three 500 kV lines in the Northwest.

The analysis of TADS also identified another set of two transmission outages whose frequency of outage was greater in the past four years (2016–2020) than in the past eight years (2012–2020). These outages were considered to have a high probability of causing a contingency in the future and are recognized in this report as "frequent transmission outages," including a 230 kV line in the Northwest and a 345 kV line in the Desert Southwest.

Approach and Implementation

Production Cost Model Approach

The study began with the 2030 ADS PCM V 2.3 case. The peak loads modeled in the 2030 ADS PCM case were average loads (i.e., 1-in-2-year loads). The case was run for August 10–23, 2030, and August 22–September 5, 2030. The August 10–23, 2030, simulation was observed to be resource adequate with no unserved energy. For the August 22–September 5, 2030, simulation, only 3.6 GW of unserved energy (about 0.01% of total load) was observed on Aug 29, 2030 (see Figure 2). This indicates that, during the simulated period, the case was already at its limit of resource adequacy.

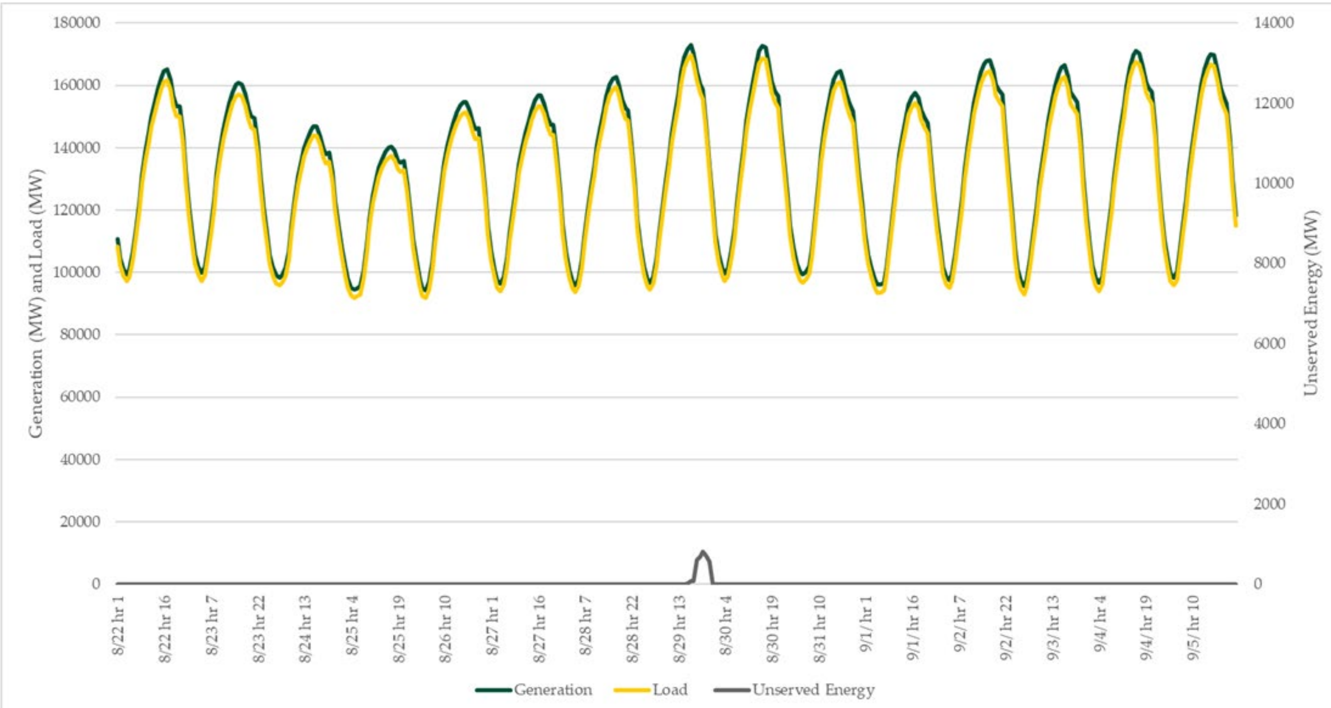


Figure 2: Load–generation balance for 2030 ADS PCM V 2.3

The 2030 ADS PCM case was then modified to create three cases using three load profiles (heat wave, 1-in-10, and 1-in-20) as described in the previous section. The resulting load profiles are shown in Figure 3 and Figure 4 for the respective periods. Even though the heat wave load profile had the highest load peak at 188 GW on 8/15/2030, hour 17 (see Figure 3), compared to 185 GW in the 1-in-20 load profile and 182 GW with 1-in-10 load profile on 8/29/2030, hour 17 (see Figure 4), there were days in the heat wave load profile when the loads were lower than or almost equal to the loads in the 2030 ADS PCM. Loads in 1-in-10 and 1-in-20 load profiles were, on average, consistently higher for each day of the studied period than 2030 ADS PCM and yielded more extreme load increases for the simulation.

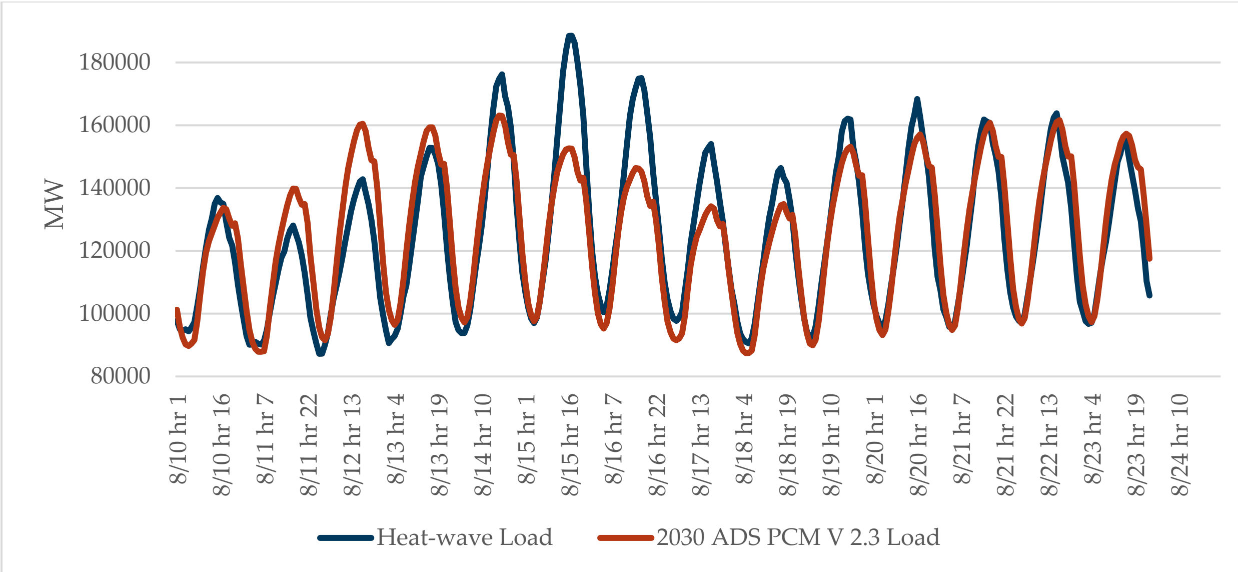


Figure 3: Comparison of heat wave and 2030 ADS PCM loads for August 10–August 23 2030

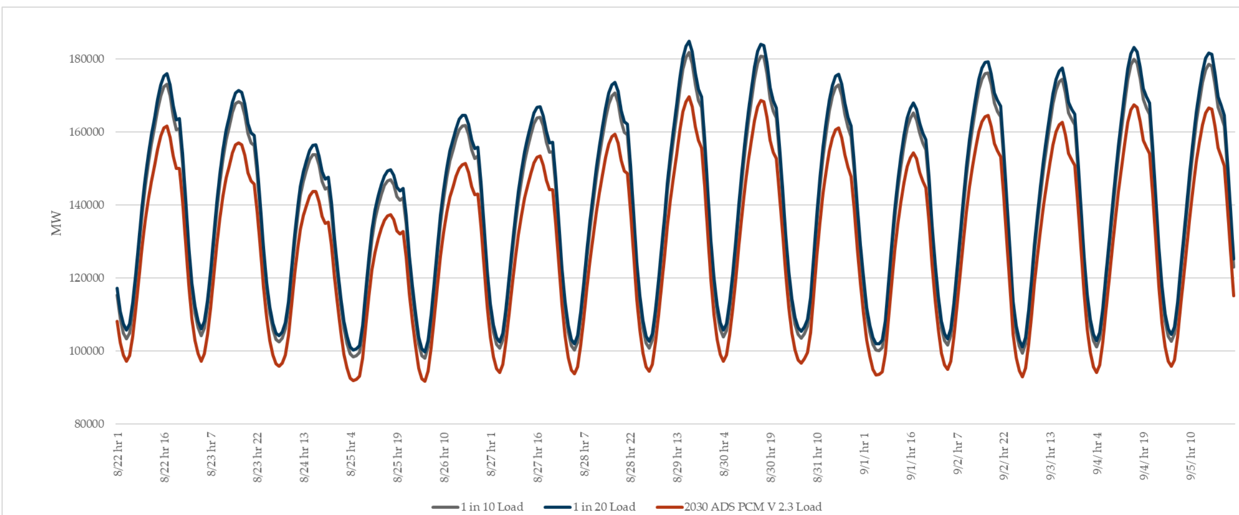


Figure 4: Comparison of 1-in-10, 1-in-20, and 2030 ADS PCM loads for August 22–Sep 5 2030

The peak loads in the heat wave load profile and the 1-in-20 load profiles were also compared as shown in Figure 5. Except for the peak load day and the day before it, the loads in the 1-in-20 load profile were higher than loads in the heat wave load profile.

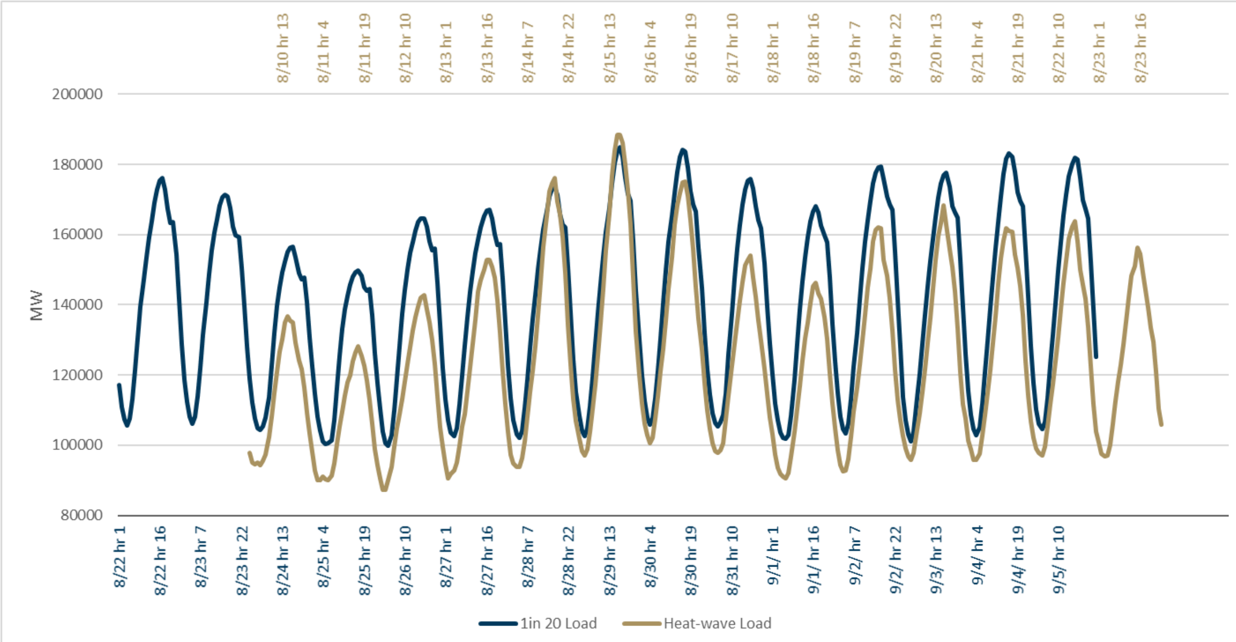


Figure 5: Comparison of peak load for heat wave and 1-in-20 load profile

The PCM cases resulting from the three load profiles mentioned above were modified further for extreme natural event assumptions as follows:

1. Coal retirements as described in Table 1 were applied to each case. The retired resources were not replaced in the cases.
2. Solar Reductions—To model solar reductions in PCM, plant capacities in each BA were reduced by the factor shown previously in Figure 1.
3. Hydro reductions—To model hydro reductions in the PCM, maximum generation of plants and hydroelectric energy available to plants in the Northwest Region were reduced by 30%.

In addition to the three cases with extreme natural event assumptions described above, each of the three cases was also modeled with the seven sustained transmission outages by taking these transmission lines out of service in the cases.

Stability and Dynamic Approach

The approach for the power flow and dynamic simulations was similar to the PCM case. To simulate a heat wave, the data attributed to the hour with the largest load in the PCM (August 15, hour 17 in the PCM case with load profiles based on the August 2020 heat wave) was exported into a power flow format, yielding a total load of 188 GW for the system. The total load in the 2030 HS PF was 191 GW, which is close to the 188 GW from the PCM, so the total load in the power flow case was kept at 191 GW. However, as a first step, the 2030 HS PF and this PCM export were compared by area and the 2030 HS PF was adjusted to match the ratio of load and generation in each area that exists in the PCM export.

To adjust the generation, the solar generation was reduced by the same percentage as in the PCM and was applied to the power flow case by BA. The solar generation in each area was decreased by the percentage shown in Figure-1. Additionally, hydro generation was reduced in the power flow by 30% in the Northwest. Generators at a plant were primarily turned off to reduce total plant output so units would not contribute to inertia on the system. The remaining generators were further adjusted as necessary to attain a 30% reduction. Other generators were turned on and area interchanges were adjusted to cover the power imbalance created by reduced hydro and solar generation.

In sum, the power flow case with extreme conditions described above (load, solar, and hydro adjustments) is described as the "ENE" case in the figures in subsequent sections.

Observations and Findings

Stability and Dynamic Results

This section describes the results, observations, and findings related to the power flow analysis, with a particular focus on the dynamic performance of the system for the cases considered.

Frequency Response Following the Loss of Generation

This section presents the results from the comparison of the frequency response of the two largest contingencies[3] in the West—Rush Creek and Revelstoke generators—and the loss of two Palo Verde units. The analysis presented in this section involves the following cases:

- Original 2030 HS PF case (Original),
- 2030 HS PF case with adjusted loads (Adjusted loads),
- 2030 HS PF case with adjusted loads and decreased solar (Adjusted loads and solar), and
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro (Adjusted loads, solar, and hydro).

Figure 6 compares the frequency response from these cases for the above-mentioned outages. It shows the median bus frequency of buses 345 kV and above (frequency is a unique value across the interconnection, so the median value is a good representation). The lowest frequency nadir of 59.817 Hz occurs in the 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro (Adjusted loads, solar, and hydro). As several weather event assumptions are added to the 2030 HS PF case, the median frequency nadir is lower, except the "Adjusted loads" case. This is due to the composite load model's reaction to low voltages in the simulation. The 1,043 MW of load tripping in the simulation for the "Adjusted loads, solar, and hydro" case causes the frequency to level out and reach a nadir of 59.88

[3] The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. From the NERC Glossary of terms https://www.nerc.com/files/glossary_of_terms.pdf

Hz. In all the simulations, the system frequency remains well above the underfrequency load shedding (UFLS) threshold of 59.5 Hz.

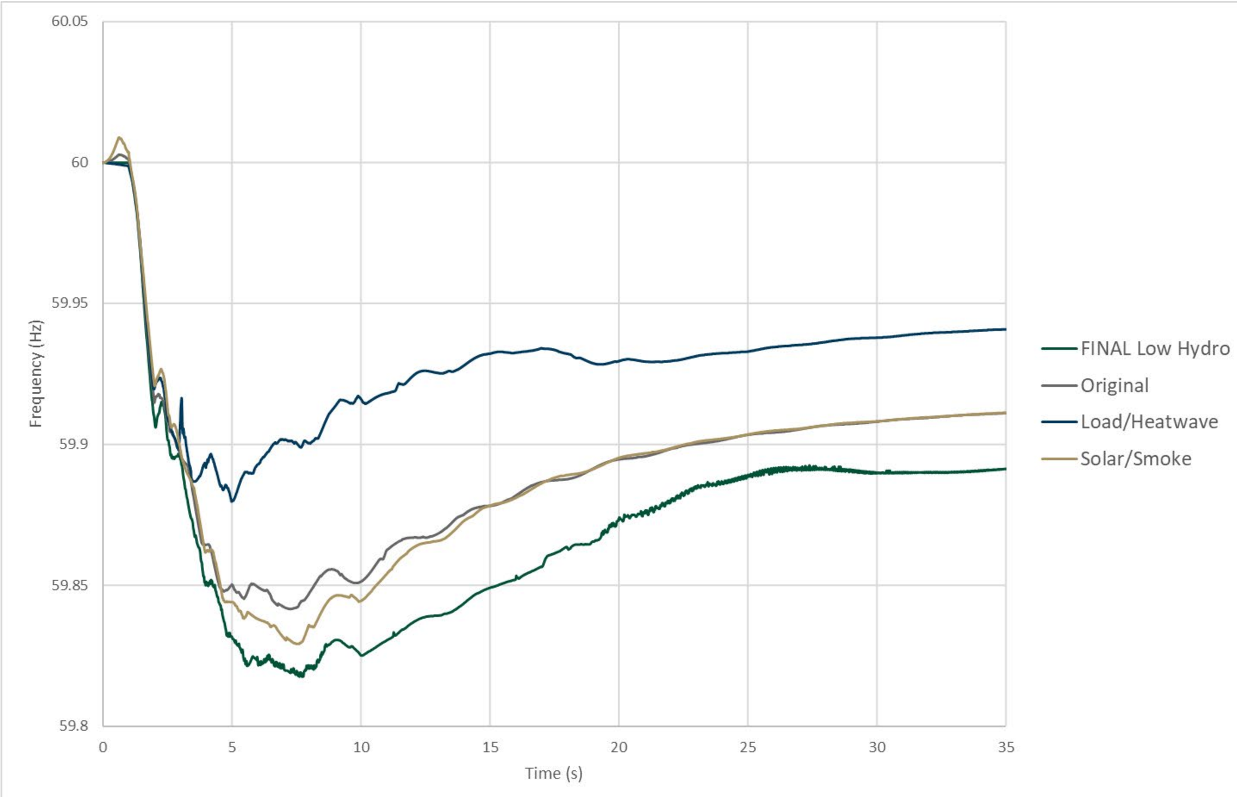


Figure 6: Rush Creek/Revelstroke Outage frequency response

Another contingency commonly studied on the WECC dynamic stability cases is the loss of two Palo Verde units (double Palo Verde or "DPV"), which results in total generation loss of 2,600 MW. The DPV contingency is one of the WECC standard disturbances and provides a large generation loss to test model stability. The analysis of the DPV outage was performed using the following cases:

- Original 2030 HS PF case (Original),
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro (ENE),
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro with seven sustained transmission outages, those identified in the TADS analysis (ENE with sustained outages), and
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro with additional coal 3 GW generation retirement, those identified in the PCM case (ENE with coal retirements),

The median of frequency values recorded across the system is a suitable measure to assess system-wide frequency response and its adequacy. Accordingly, the results of median frequency of buses 100 kV and greater was compared below in Figure 7. At first inspection, the 2030 HS PF case has the worst frequency response with a frequency nadir of 59.83 Hz. However, the lack of frequency decline in the simulations shown in Figure 7 was again caused by a decrease in load from the composite load model.

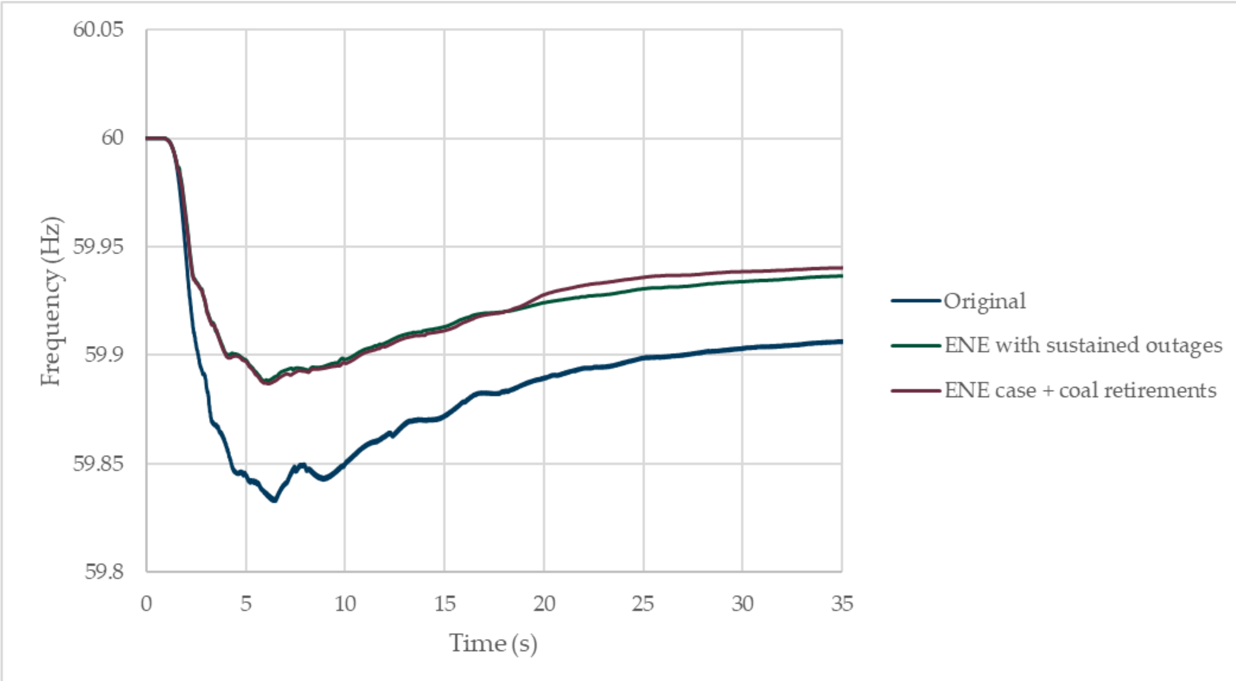


Figure 7: Frequency Response of DPV Outage

Figure 8 shows the largest frequency deviations that were observed. In the DPV outage, the rate of change of frequency (RoCoF) for the original 2030 HS PF case is larger and the frequency nadir further away from the nominal frequency than that of the cases with and without the additional coal retirements. However, upon further inspection, the ENE case disconnects about 927 MW of load in the simulation and the ENE case with additional coal retirements drops about 1,037 MW of load, keeping the frequency from declining more rapidly. A comparison of the worst frequency deviation of the three cases reveals that, in the ENE case with coal retirements (labeled “ENE+outages+retirements”), frequency declines to 59.7 Hz, and the frequency excursion was 0.67 Hz. In the ENE case (labeled “ENE”), it declines to 59.83 Hz, with a deviation of 0.59 Hz. In the 2030 HS PF case, it declines only to 59.82 Hz, with the deviation of only 0.18 Hz, which is the largest in the simulation.

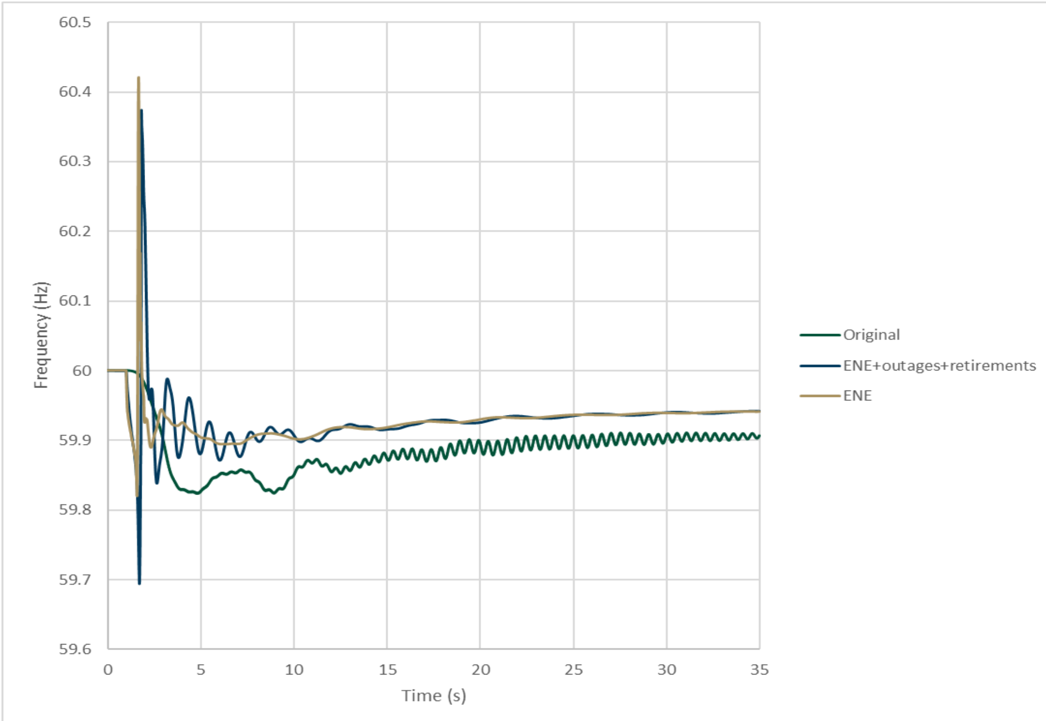


Figure 8: Frequency Response of DPV Outage with Largest Bus Spread Per Case

To demonstrate the root cause of load tripping in the extreme natural event cases, the voltage profiles on a bus that dropped load are shown in Figure 8 as an example. The voltage profile on other buses that dropped load was similar and, so, not shown. The voltage drops to 0.65 pu, passing the threshold of 0.72 pu, triggering the electric load to reduce as part of the composite load model, but does not reach the 0.52 pu threshold to fully open the load.

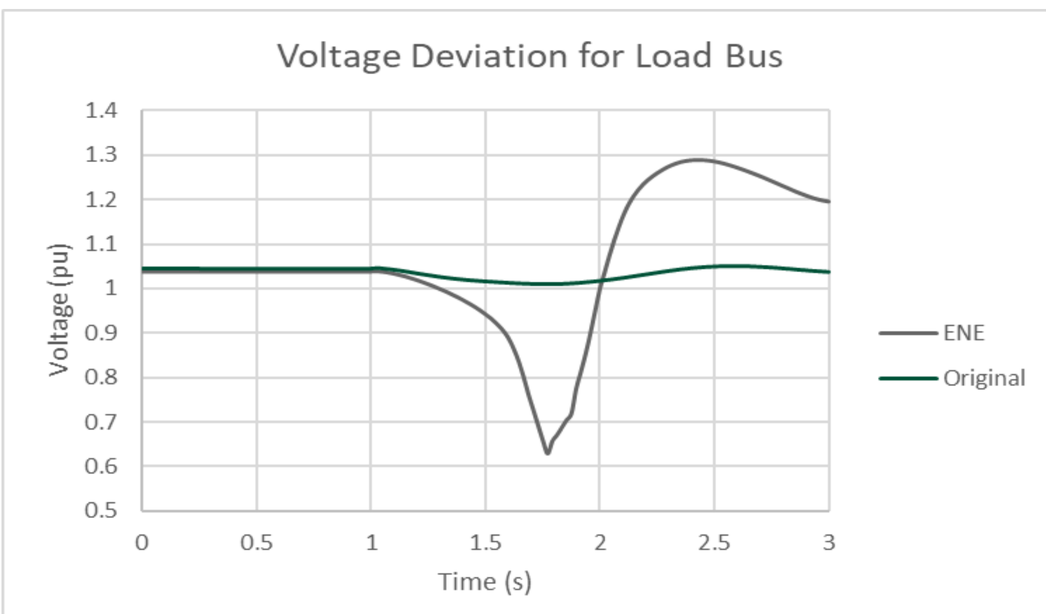


Figure 9: Voltage Deviation for Load Bus

Note the decrease of 31 GVA*s, or 3%, in inertia between the 2030 HS PF and the ENE case without coal retirements (labeled "ENE") due to the hydro reduction. The additional coal retirements will reduce system inertia even more.

Frequency Dynamics Following Transmission Contingency

Additional analysis was performed to understand system response following two transmission contingencies, which were simulated independently (as N-1) and also simultaneously (as N-2) for dynamic stability analyses. The following cases were considered for this analysis:

- Original 2030 HS PF case (Original), and
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro with seven sustained transmission outages, those identified in the TADS analysis (ENE with sustained outages).

These two lines were identified for transmission contingency dynamic analysis according to the processing of historic TADS data, as the frequency of their forced outages during the summer season has increased over the past few years. As seen in Figures 10 through 12, the dynamic contingency analyses of the single 230 kV and 345 kV lines showed distinctive responses when looking at frequency; though, the range of system frequencies observed remained within the acceptable range. In the loss of the 230 kV transmission line in the Northwest (see Figure 10), the frequency spiked to 60.05 Hz in the ENE with sustained outages case because of a disconnection of composite loads, whereas, in the 2030 HS PF base case, it only spiked to 60.01 Hz and sustained. In the loss of the 345 kV transmission line in the Southwest (see Figure 11), the frequency gradually declines to near 59.98 Hz and then recovers and settles at 59.995 Hz, whereas, in the 2030 HS PF base case, it gradually drops to 59.995 Hz and settles at 60.01 Hz. In the simultaneous loss of both lines (see Figure 13), the frequency response is such that a distinctive pattern of frequency response from each outage is visible; both the immediate sharp spike and the gradual recovery can be observed. Following the simultaneous loss of the two lines, even though the initial spike and nadir for the extreme natural event case (labeled "ENE with sustained outages") and the base case (labeled "Original") differ, the settling frequency in both cases is almost identical at 60.01 Hz. Note that the frequency spike following the forced outage of the 230 kV line in the Northwest can be attributed to the decrease in hydro generation in the Northwest region, which results in high utilization of the paths. So, when a line is tripped, the resulting bus voltages in the area decrease considerably, and a significant decrease in load occurs, which in turn results in an increase in frequency.

The results from voltage dynamics are discussed in the next section.

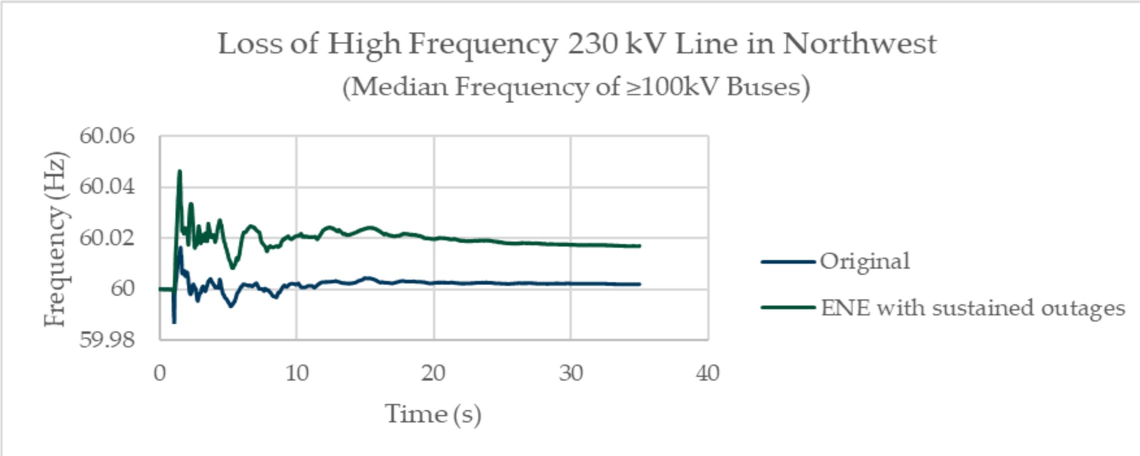


Figure 10: Frequency response to loss of 230 kV line in Northwest

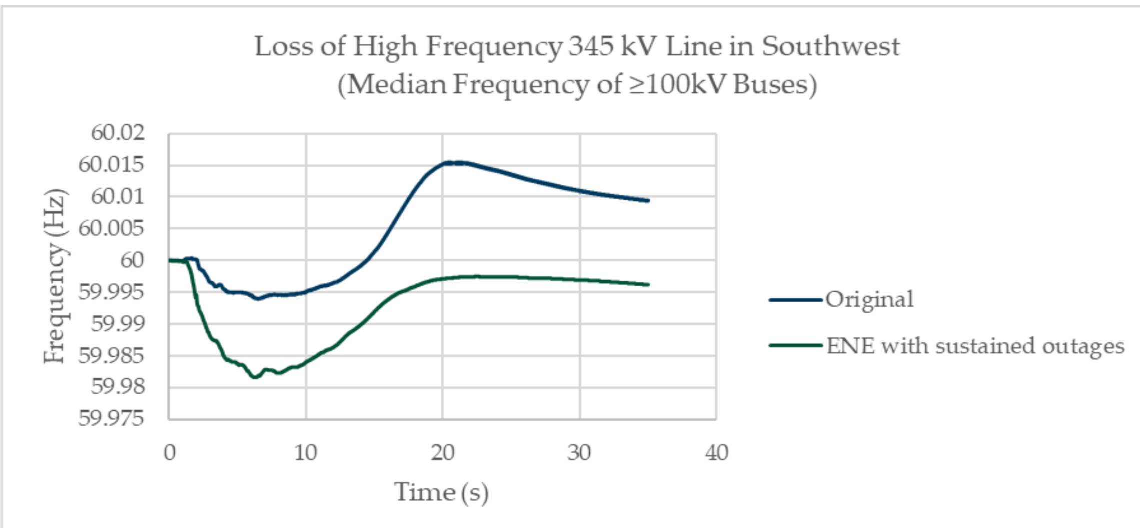


Figure 11: Frequency response to loss of 345 kV line in Southwest

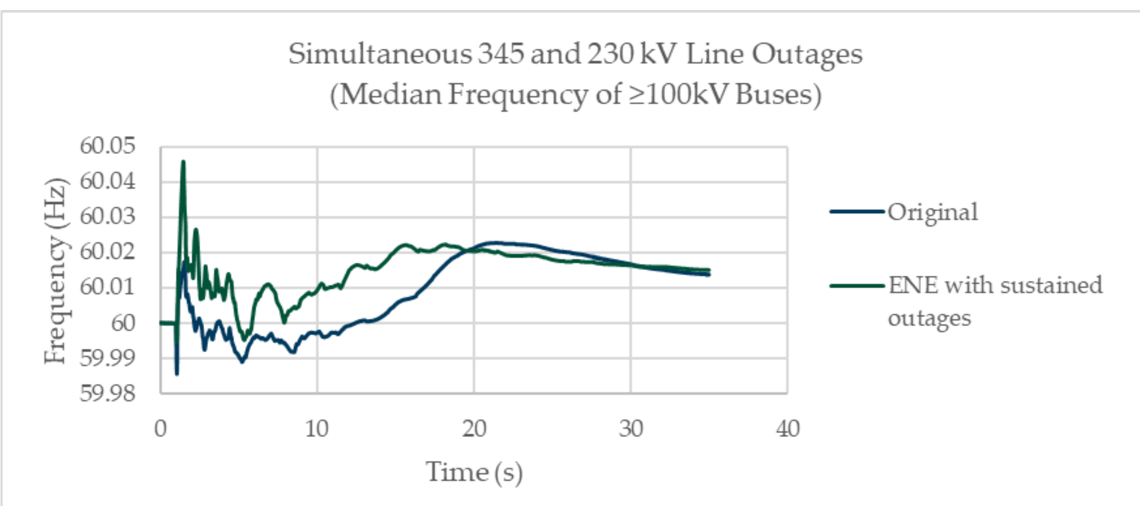


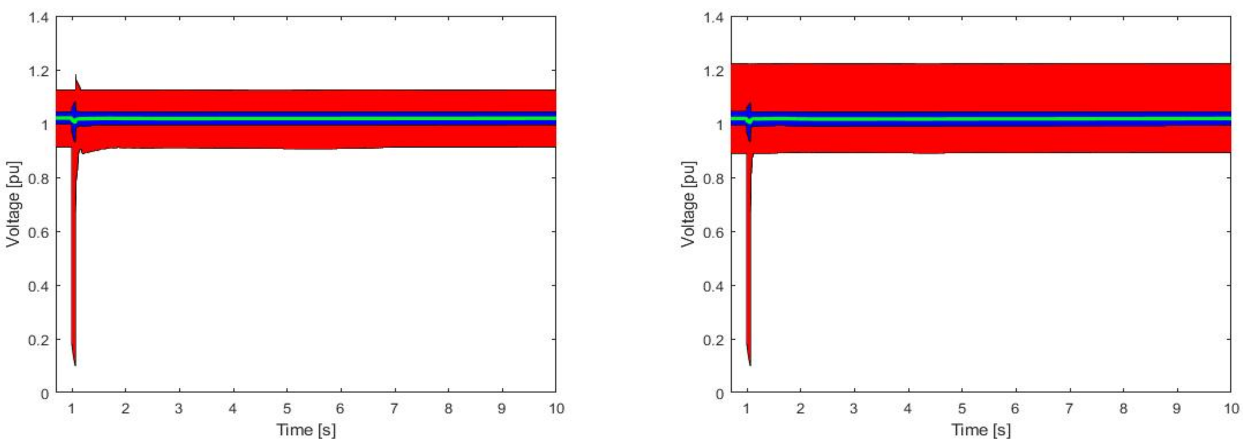
Figure 12: Frequency response to simultaneous high frequency outages

Voltage Dynamics Following Transmission Contingency

This section presents the results of voltage dynamics following the contingency of the two lines explained in the previous section. The following cases were considered for this analysis:

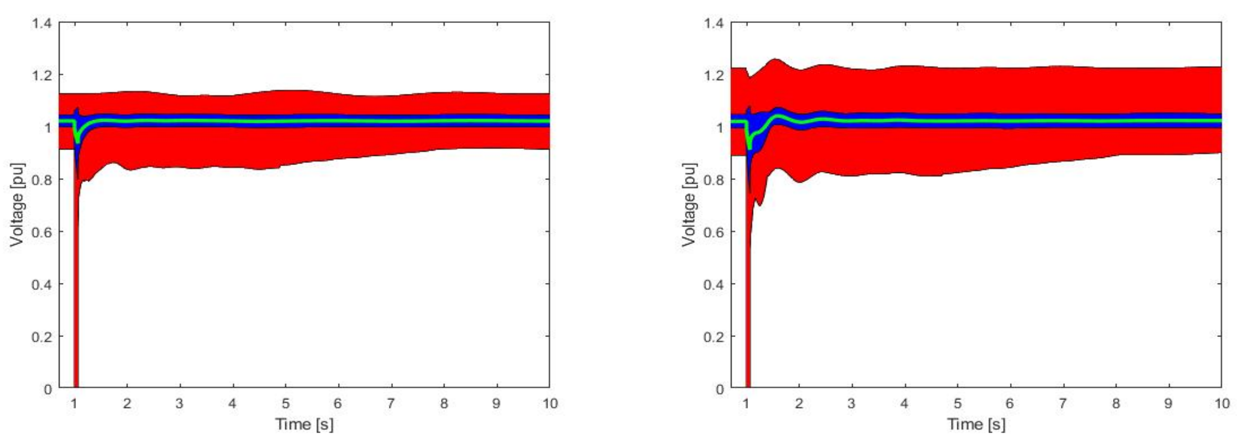
- Original 2030 HS PF case (Original), and
- 2030 HS PF case with adjusted loads, decreased solar, and decreased hydro with seven sustained transmission outages identified in the TADS analysis (ENE with sustained outages case).

Unlike frequency, voltage values vary across the interconnection within a standard range, so the analysis presents the range of voltage values observed across the system. These results are presented in Figure 13, Figure 14, and Figure 15, and each plot contains three subplots: (1) the green trace that indicates the mean of observed voltage values, (2) the blue trace that shows the 75th percentile of the observed voltage values, and (3) the red trace that shows the complete range of observed voltage values.



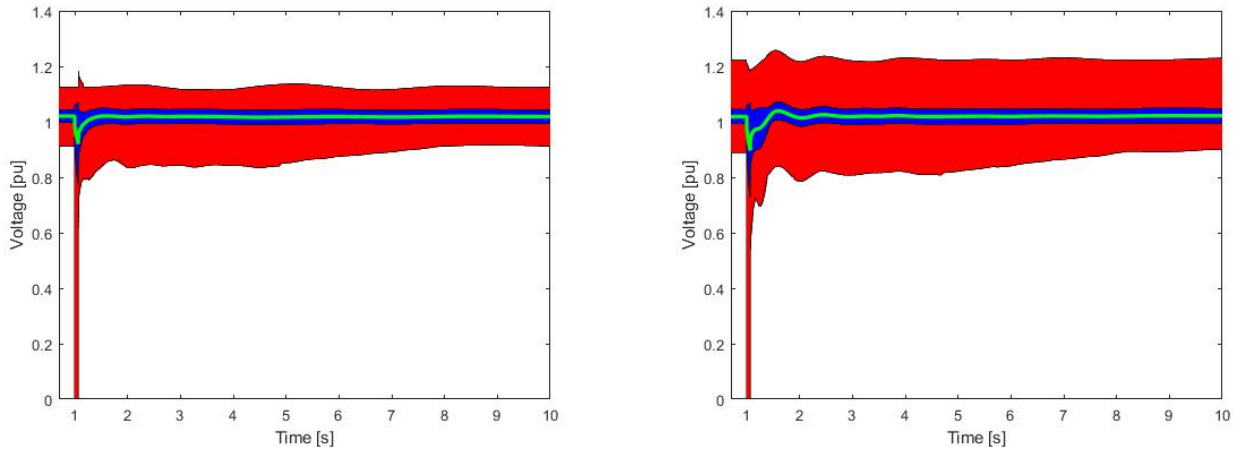
(a) 2030 HS PF (b) ENE with sustained outages

Figure 13: Range of voltage across WECC system following outage of 345 kV line in Southwest



(a) 2030 HS PF (b) ENE with sustained outages

Figure 14: Range of voltage across WECC system following the outage of 230 kV line in Northwest



(a) 2030 HS PF (b) ENE with sustained outages

Figure 15: Statistical characterization of voltage following the simultaneous outage of 230 kV and 345 kV lines

As shown in Figure 13, Figure 14, and Figure 15, the voltage dynamics exhibit more oscillatory behavior in all ENE with sustained outages cases relative to the 2030 HS PF cases while the range of voltage increases. To further investigate this observation, three metrics were used to assess the voltage dynamics (see Figure 16).

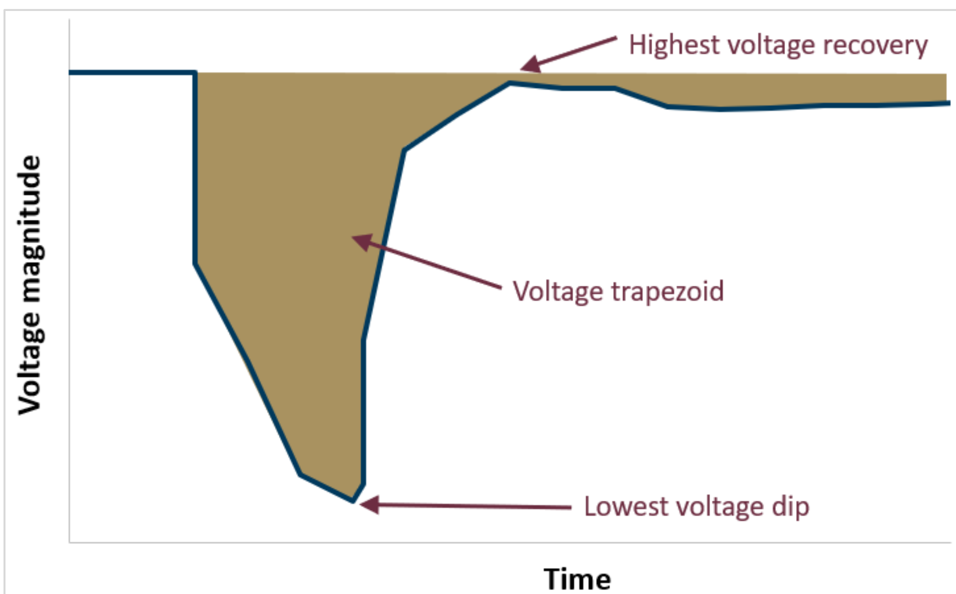
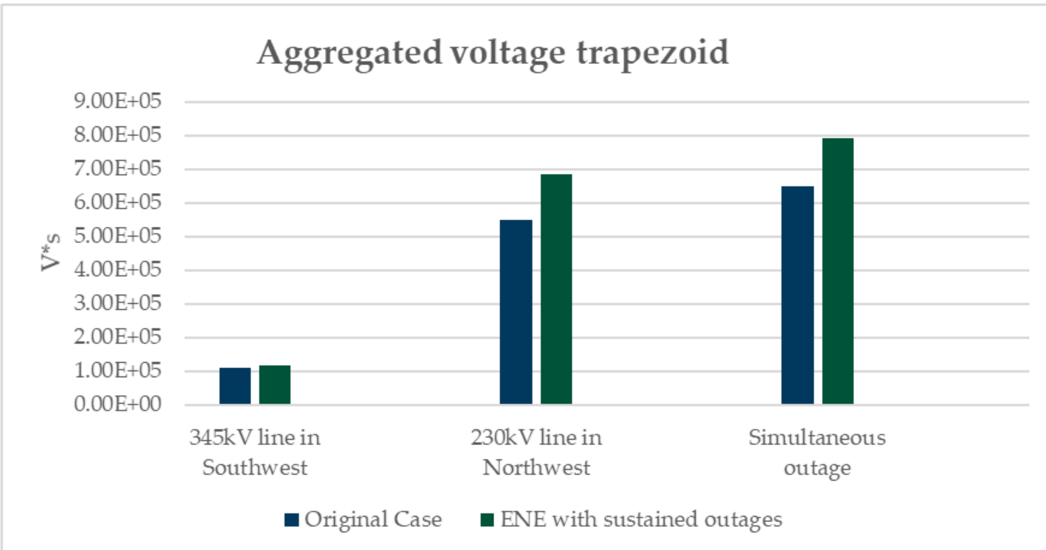


Figure 16: Conceptual depiction of metrics used to evaluate voltage dynamics

- The first metric is the voltage trapezoid, which is the area between the transient voltage profile and its pre-disturbance value; the smaller this metric, the less oscillatory the voltage.
- The second and third metrics are the lowest voltage dip and highest recovery voltage, which indicate the voltage swings; the lowest voltage dip and the highest voltage recovery values across the system should remain within the standard range to prevent the triggering of protective equipment.

The first metric is presented in two forms; (i) the aggregate value, pertaining to the summation of voltage trapezoid values for all measured voltages across the WECC system and, (ii) the maximum individual voltage trapezoid value observed. These results are shown in Figure 17, and Figure 18 indicate in the simulation results of the various transmission outages, the voltage trapezoid was increased, meaning the voltage oscillations were exacerbated, relative to the 2030 HS PF cases. The aggregate voltage trapezoid in ENE with sustained outages case was 7% higher than in the base case for the outage of a 345 kV line in the Southwest. And 25% and 22% higher for the outage of the 230 kV line in the Northwest and simultaneous outage of both 230 kV and 345 kV lines, respectively. This observation suggests the adverse impact of extreme natural event conditions on voltage dynamics and oscillations.



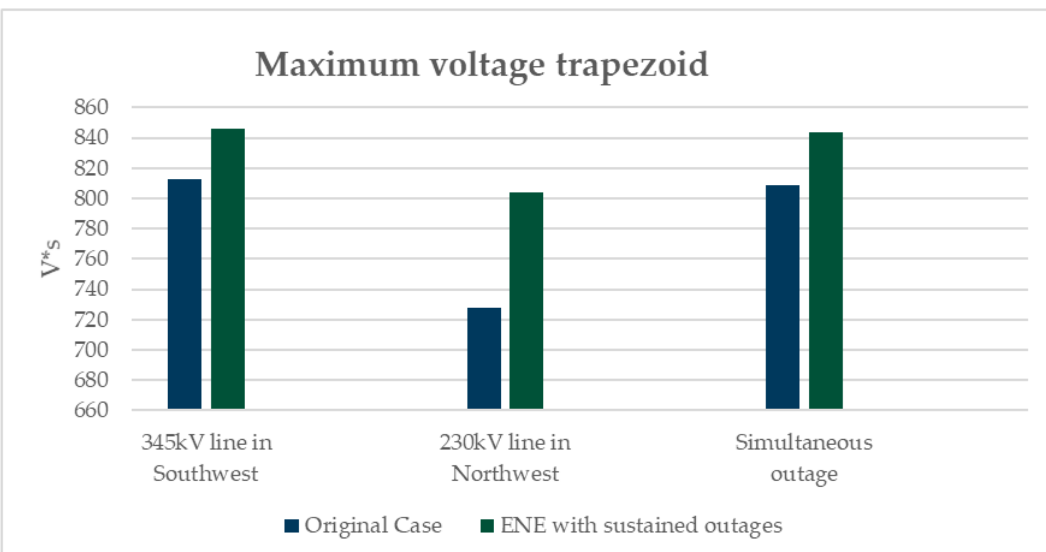


Figure 17: Comparison of voltage trapezoid for the cases considered

The results from transient low- and high-voltage values are such that, in all ENE with sustained outages cases, the lowest voltage dip remained either almost unchanged or dropped lower, while the transient overvoltage increased. The lowest voltage dip in the ENE with sustained outages case for the outage of 345 kV line was almost unchanged relative to the 2030 HS PF case, while it was 0.08 pu lower for the outage of 230 kV line and the simultaneous outage of both lines. The highest over voltages in the ENE with sustained outages cases were 0.097, 0.12, and 0.12 pu higher than the 2030 HS PF cases for the outage of the 345 kV line, the outage of the 230 kV line, and the simultaneous outage of both lines, respectively. Collectively, these results suggest the voltage stability could be affected by extreme weather conditions, but the cases considered did not result in voltage instability.

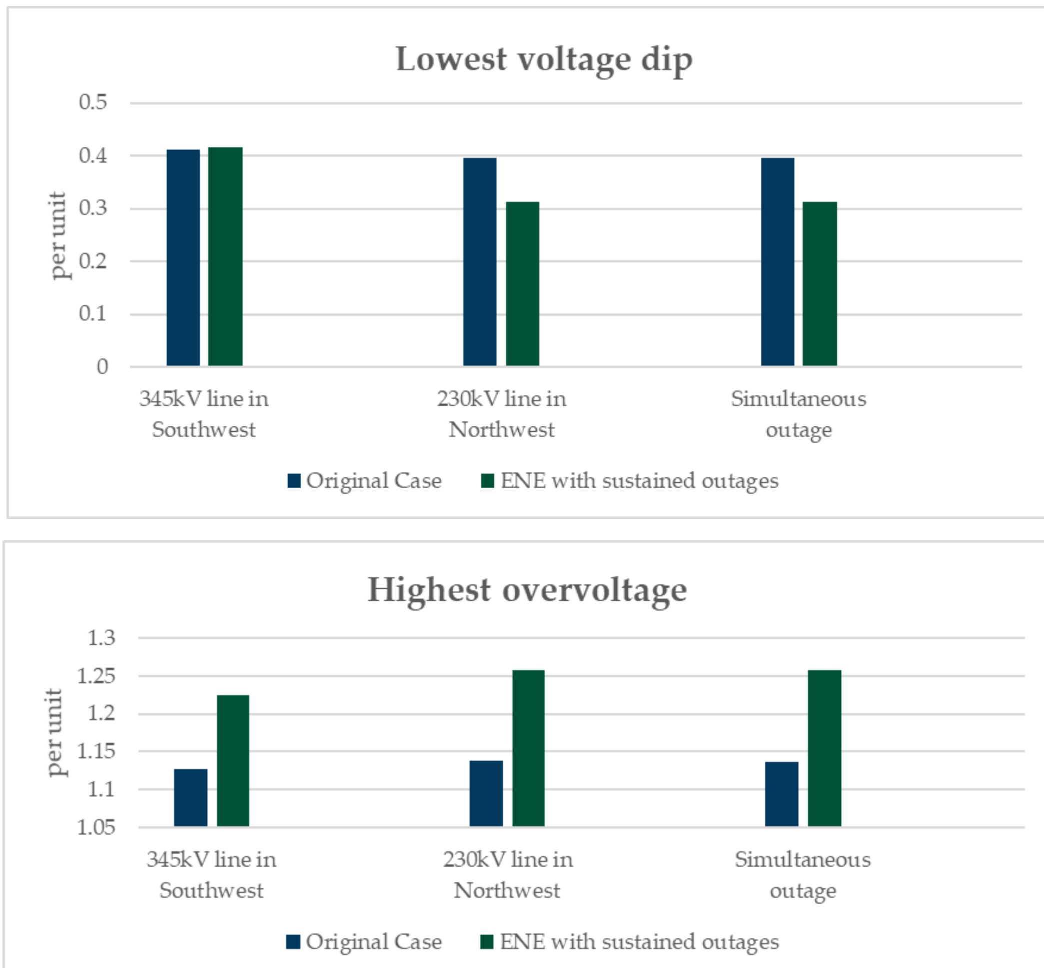


Figure 18: Comparison of transient voltage metrics for the cases considered

Production Cost Model Results

The PCM analysis of the modeled extreme natural events examined four reliability metrics:

1. Unserved energy: Can all demand for energy be met during the extreme natural event?

2. Ancillary services: During the extreme natural event, can spinning reserve, regulation up and down, and load-following up and down requirements be met?
3. Transmission flows: Does the extreme natural event change WECC Path utilization in ways that create reliability risks?
4. Transmission Outages: How do sustained transmission outages affect unserved load, the ability to maintain required ancillary services, and WECC Path utilization?

The results of the PCM simulation for the three load profiles (heat wave, 1-in-10 and 1-in-20) have similar results for the reliabity metrics studied, but results are more pronouced going from the heat wave load profile to the 1-in-10 load and 1-in-20 load profiles. The PCM results from the 1-in-20 load profile, with or without the seven sustained outages, are presented here. These cases are referred to as follows in this section and subsequent sections.

Table 2: Extreme Natural Event Assessment Case Identifications

Case Identification	Case Description
1-in-20 Load ENE	Loads based on 1-in-20 probabilities for Aug 22–Sep 5 2030 with solar and hydro reductions and coal retirements
1-in-20 Load ENE w/outages	Loads based on 1-in-20 probabilities for Aug 22–Sep 5 2030 with solar and hydro reductions, coal retirements and with seven sustained transmission outages.

Unserved Energy

The study period for the 1-in-20 load profile was August 22–September 5, 2030. Unserved energy was observed in 34 of the 360 hours of the simulation period. The results in Figure 19 show that most of the unserved energy occurred on August 29 and September 4 during the evening ramp hours when solar production was declining.

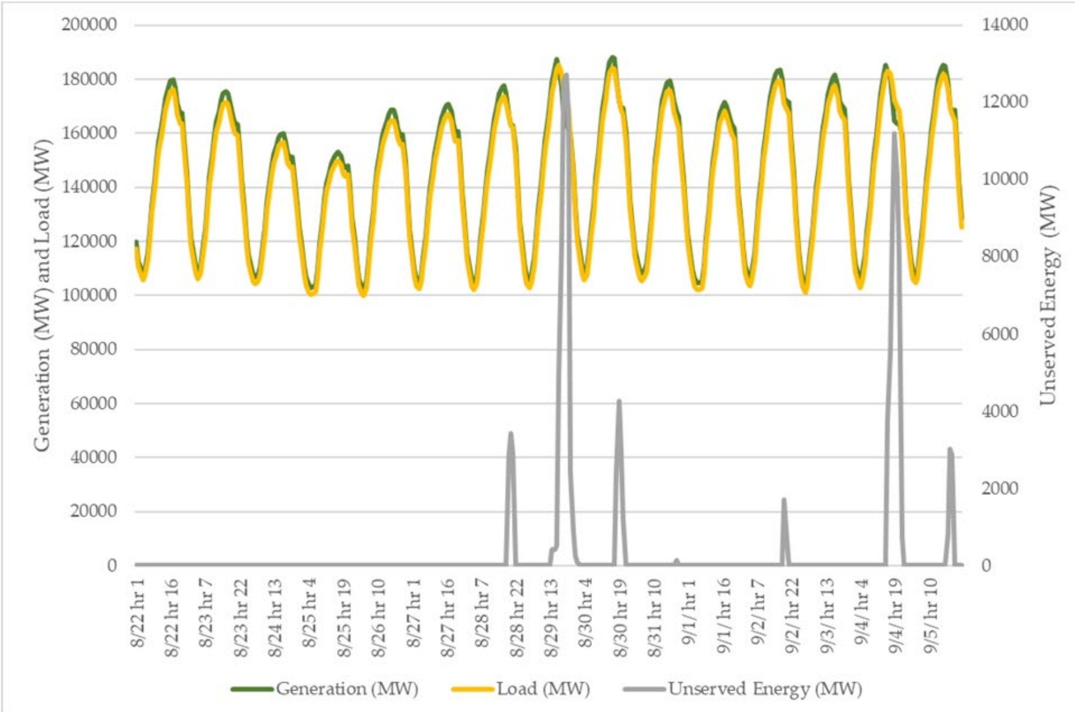


Figure 19: Systemwide unserved energy for 1-in-20 Load ENE case

Figure 20 below shows the unserved energy experienced by each BA for the entire simulation period. The appendix includes a map of BA boundaries in Figure 33, and BA names and abbreviations in Table 5. The highest unserved energy was observed in CA_CISO, followed by NW_BPAT and NW_PGE. BAs with no unserved load are excluded from this figure.

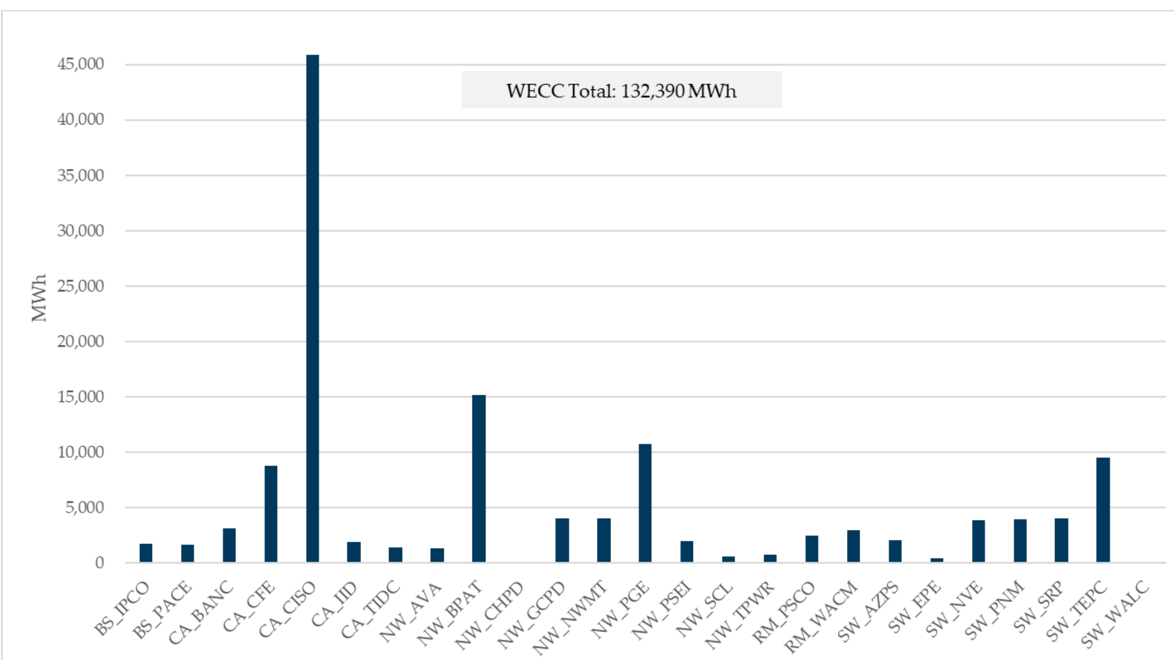


Figure 20: Amount (MWh) of unserved energy by BA in 1-in-20 Load ENE case

The BAs were combined into broader regions, as shown in Figure 21, to show the impact of an extreme natural event on inter-regional transfers. Figure 21 shows the percentage change in exports between regions from 2030 ADS PCM V 2.3 case to 1-in-20 load ENE case (refer to Table 6 in the appendix for data behind this figure). The most significant changes in interregional transfers are a reduction from British Columbia and the Northwest into California. This is due lower hydro generation available to export from the Northwest region to California. Overall, most of the regions are exporting less energy to their neighbors during extreme natural event conditions.

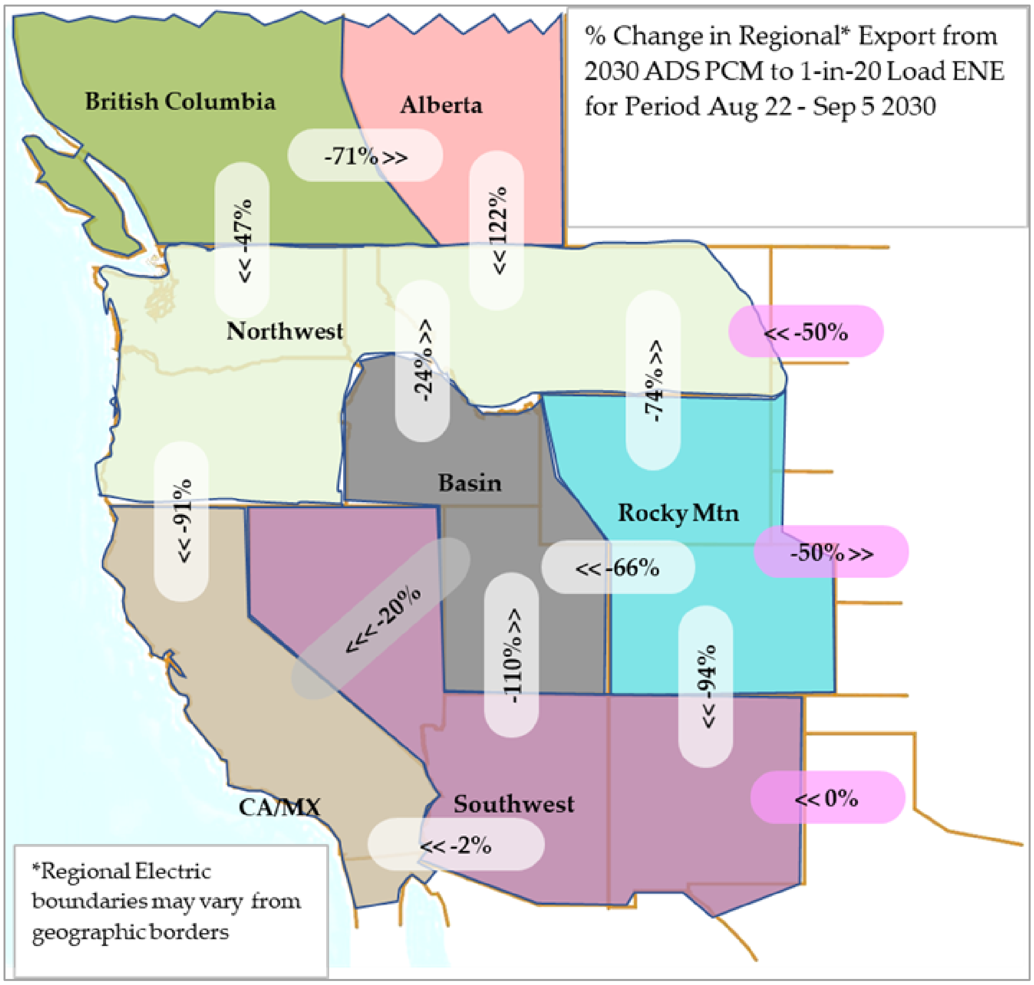


Figure 21: Net change in inter-regional transfers from 2030 ADS PCM V2.3 to 1-in-20 Load ENE case

Table 3 shows the regional net imports and exports. Regions that typically rely on imports, e.g., California, the Northwest, and Alberta, had significantly lower net imports, as shown in Table 3 (26%,38% and 96% reduction respectively, as compared to the 2030 ADS PCM V 2.3). Except for the Southwest, all regions with net exports (British Columbia, Basin, Rocky Mountain) had significantly lower exports during extreme natural event conditions as compared to 2030 ADS PCM V2.3. This indicates that, during extreme natural event conditions, the generation and transmission export capabilities would be limited and could pose a reliability risk, as a region may not be able to rely on its neighboring regions for energy imports.

Table 3: Change in net import or export in a region

Net Imports/Exports	% Change in Regional Import or Export
California imports	-26%
Northwest imports	-38%
Alberta imports	-96%
British Columbia exports	-51%
Basin exports	-30%
Rocky Mountain exports	-76%
Southwest exports	15%

Figure 22 shows that multiple BAs experienced several hours of unserved energy, with CA_CISO having the hightest number of hours of unserved load followed by SW_AZPS and SW_TEPC. BAs with no unserved energy for any hour were excluded from this figure.

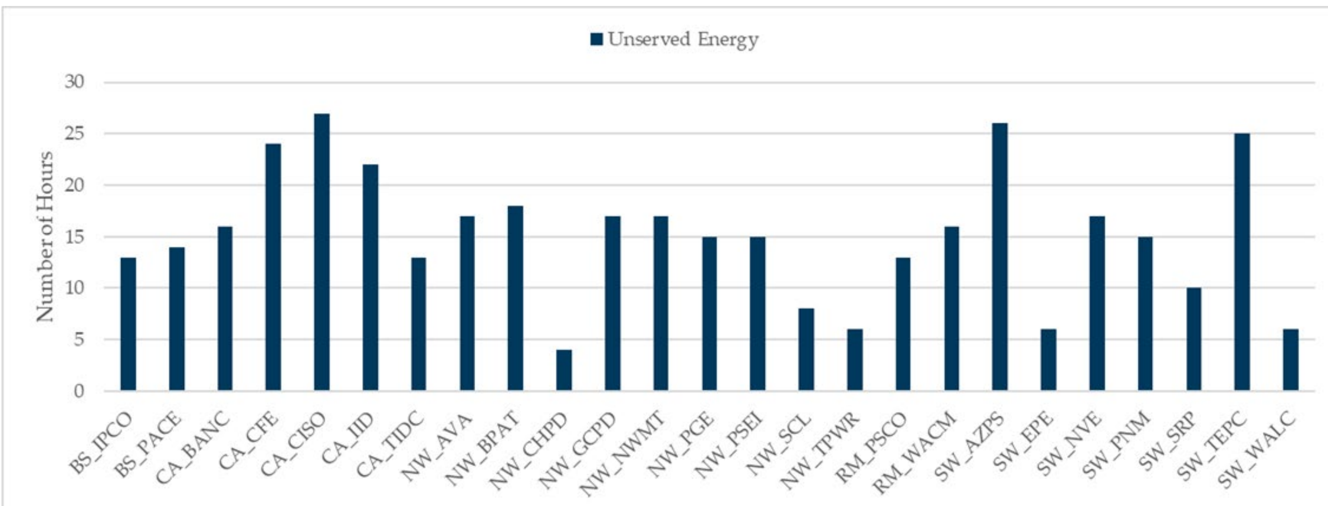


Figure 22: Hours of unserved energy by BA for 1-in-20 Load ENE case

Ancillary Services

Regulation and spinning reserves, and in some regions, supplemental operating reserves (load-following), were analyzed. Most BAs are part of reserve sharing groups (for spinning reserves only) as defined in Table 4. Figure 23 shows only the combined reserved sharing groups as modeled in the PCM. BA abbreviations and names are defined in Table 5 in the appendix.

Table 4: Reserve Sharing Groups

Reserve Sharing Group Name	Regions Included in Reserve Sharing Group
Spin_RSG_NW	BS_IPCO
	SW_NVE
	NW_NWMT
	CA_TIDC
	NW_PSEI
	NW_PGE
	CA_BANC
	BS_PACE
	NW_PACW
	NW_WAUW
	NW_AVA
	NW_SCL
	NW_GCPD
	NW_DOPD
	NW_CHPD
	NW_BPAT
Spin_RSG_RM	RM_WACM
	RM_PSCO
Spin_RSG_SW	SW_SRP
	SW_TEPC
	CA_LDWP
	SW_PNM
	SW_EPE
	SW_WALC
	SW_AZPS
	CA_IID

Figures 23 through 27 show the number of hours (binding hours) when the enforced ancillary services[4] requirements were not being met for both 1-in-20 Load ENE case and 2030 ADS PCM V 2.3. BAs that met ancillary service requirements for all hours are excluded from these figures.

Figure 23 shows that the AESO and CISO regions and reserve sharing groups RSG_RM and RSG_SW see a significant increase in the number of hours when spinning reserve requirements [6] are not being met. Throughout Western Interconnection, there was a 147-fold increase in hours in which spinning reserves were not met in the 1-in-20 load case.

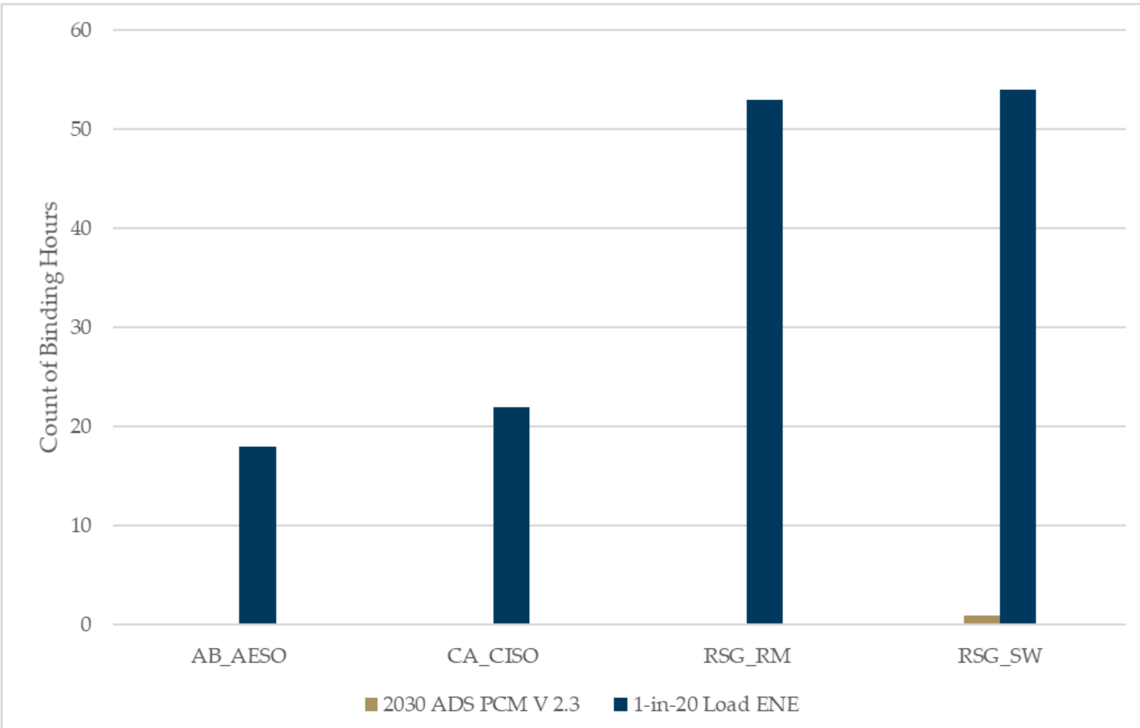


Figure 23: Hours of unmet spinning reserve

Figure 24 shows hours during which regulation[5] up requirements were not served for a region and compares them to the 2030 ADS PCM V 2.3. Several BAs see a significant increase in the number of hours when this requirement was not being met for 1-in-20 Load ENE case. Across the Western Interconnection, there was a 29-fold increase in hours when the regulation up requirement was not met in the 1-in-20 Load ENE case compared to the ADS case.

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[4] For a summary of ancillary services enforced in the 2030 ADS, see ADS Release Notes, Sec 7.6: Ancillary Service Model [11].

[5] For a definition of regulation ancillary services, see Separating and measuring the regulation and load-following ancillary services, Abstract [12].

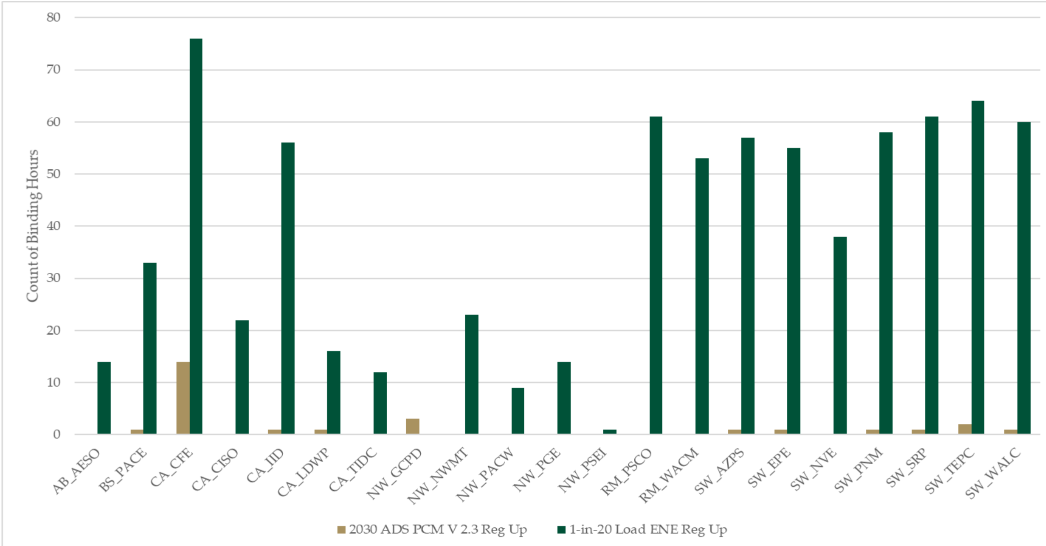

Figure 24: Hours of unmet regulation up by BA

Figure 25 shows hours in which load-following[6] up requirements were not served for a BA and compares them to the 2030 ADS PCM V 2.3. Like regulation up, some BAs see an increase in the number of hours this requirement is not being met in the 1-in-20 Load ENE case compared to the 2030 ADS PCM V 2.3 case. Across the interconnection, there was a 28-fold increase in hours in which the load-following up requirement was not met in the 1-in-20 Load ENE case relative to the ADS case.

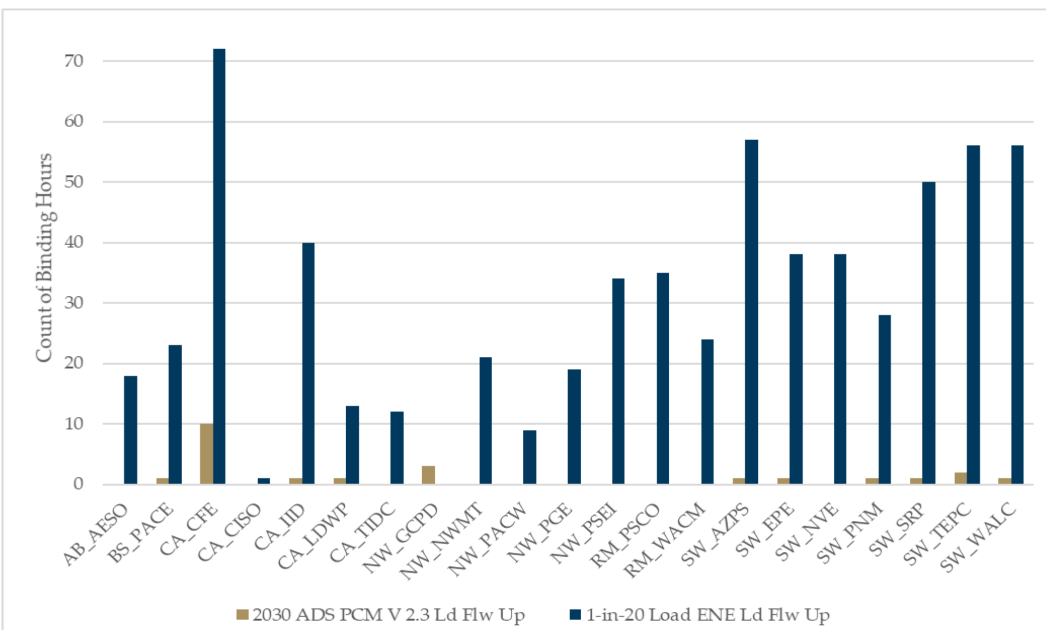

Figure 25: Hours of unmet load-following up by BA

[6] For a definition of load-following ancillary services, see Separating and measuring the regulation and load-following ancillary services, Abstract [12].

Figure 26 and Figure 27 show hours in which ancillary services regulation down and load-following down requirements were not met for a BA and compares them to the 2030 ADS PCM V 2.3. For both requirements, there is an increase in the number of hours for a few BAs during which the requirements are not being met in the 1-in 20 Load ENE case as compared to 2030 ADS PCM V 2.3 case. Across the Western Interconnection, for both regulation down and load-following down, there was a 1.5-fold increase in hours in which these requirements were not met in the 1-in-20 Load ENE case relative to the ADS case.

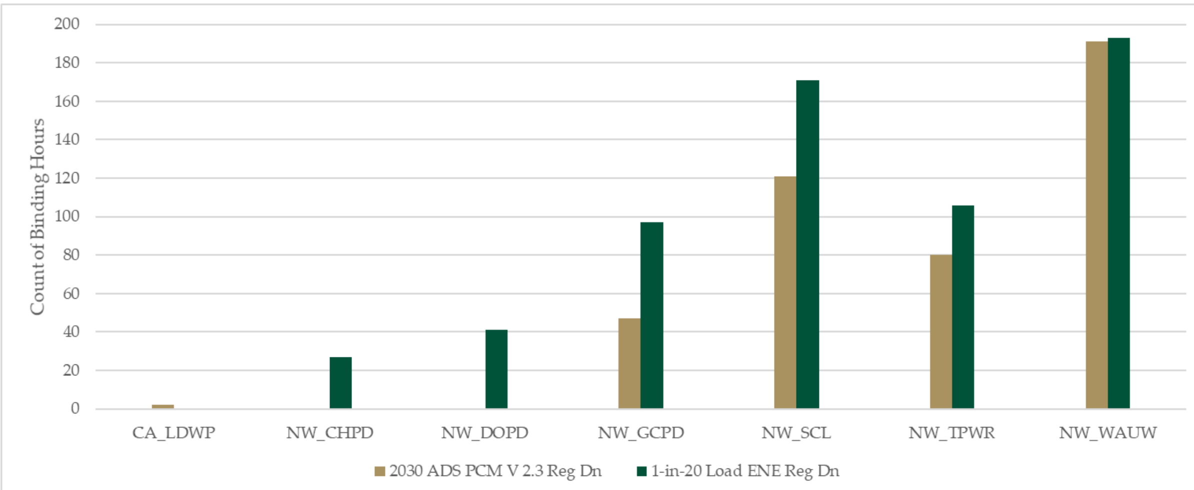

Figure 26: Hours of unmet regulation down by BA

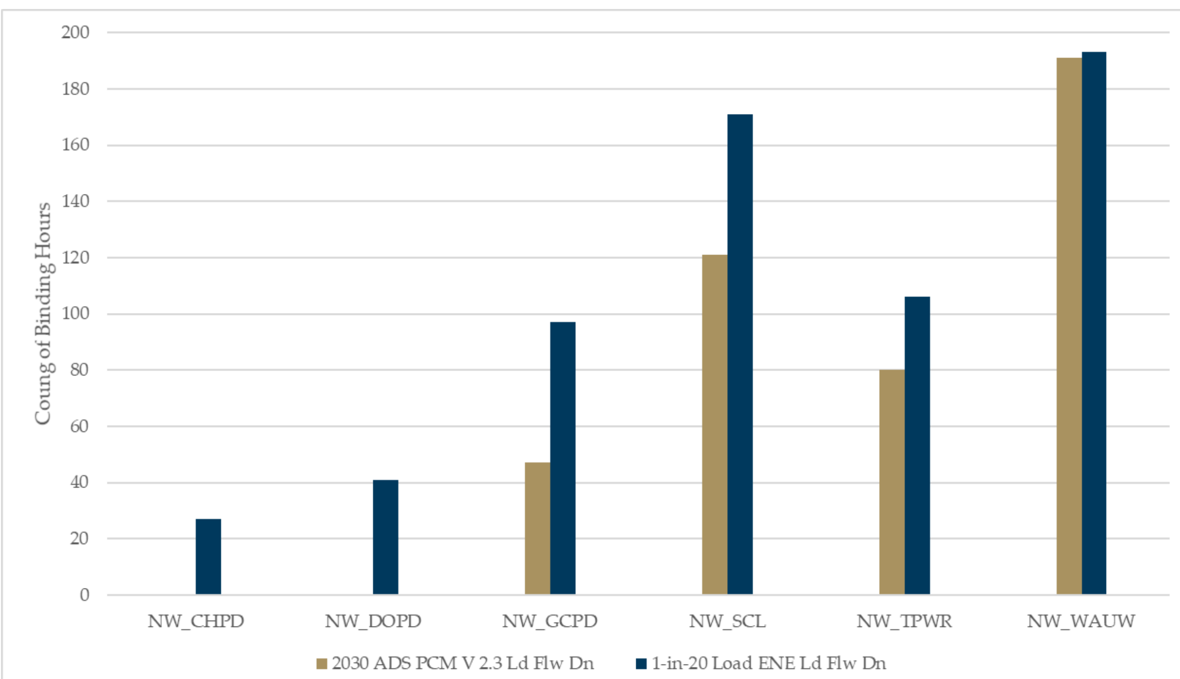

Figure 27: Hours of unmet load-following down by BA

Transmission Flows

The following metrics were used to identify transmission Paths that are “highly utilized”:

- U75 designates Paths that are utilized at 75% or more of their rated capacities for 50% or more of the hours for the duration of the simulation.
- U90 designates Paths that are utilized at 90% or more of their rated capacities for 20% or more of the hours in for the duration of simulation; and
- U99 designates Paths that are utilized at 99% or more of their rated capacities for 5% or more of the hours for the duration of simulation.

Any Path that meets one or more of these criteria is identified as “highly utilized” in Figure 28.

Figure 28 shows the several major paths, including Path 26 in California, which normally carries significant flows, exceed the U99 metric. Figure 29 shows that several paths have a significant increase in their path utilization for the 1-in-20 Load ENE case as compared to 2030 ADS PCM V2.3. Path 3 (P03 Northwest-British Columbia) and Path 83 (P83 Montana Alberta Tie Line) see the most increase (10% and 23%, respectively) for U99 metric.

Exceeding the metrics described above does not necessarily mean there is a reliability risk. However, the Paths shown with high use may warrant further investigation and evaluation by transmission operators and planners.

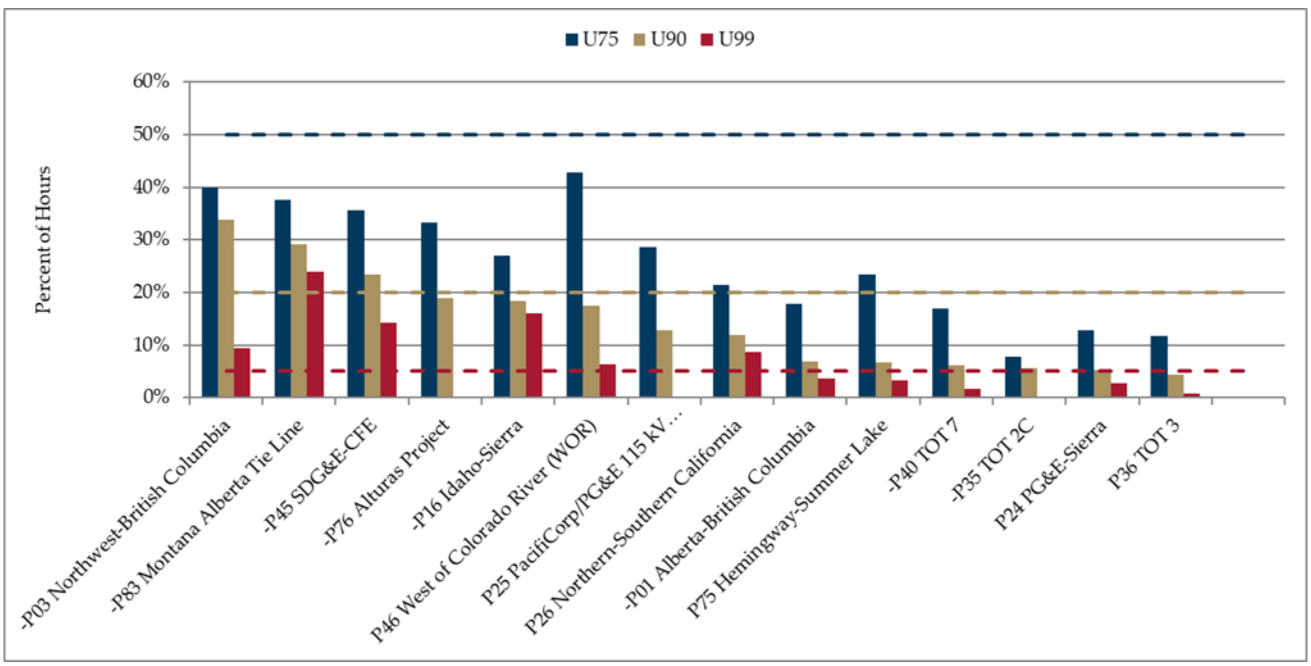

Figure 28 Most heavily utilized paths in 1-in-20 Load ENE case

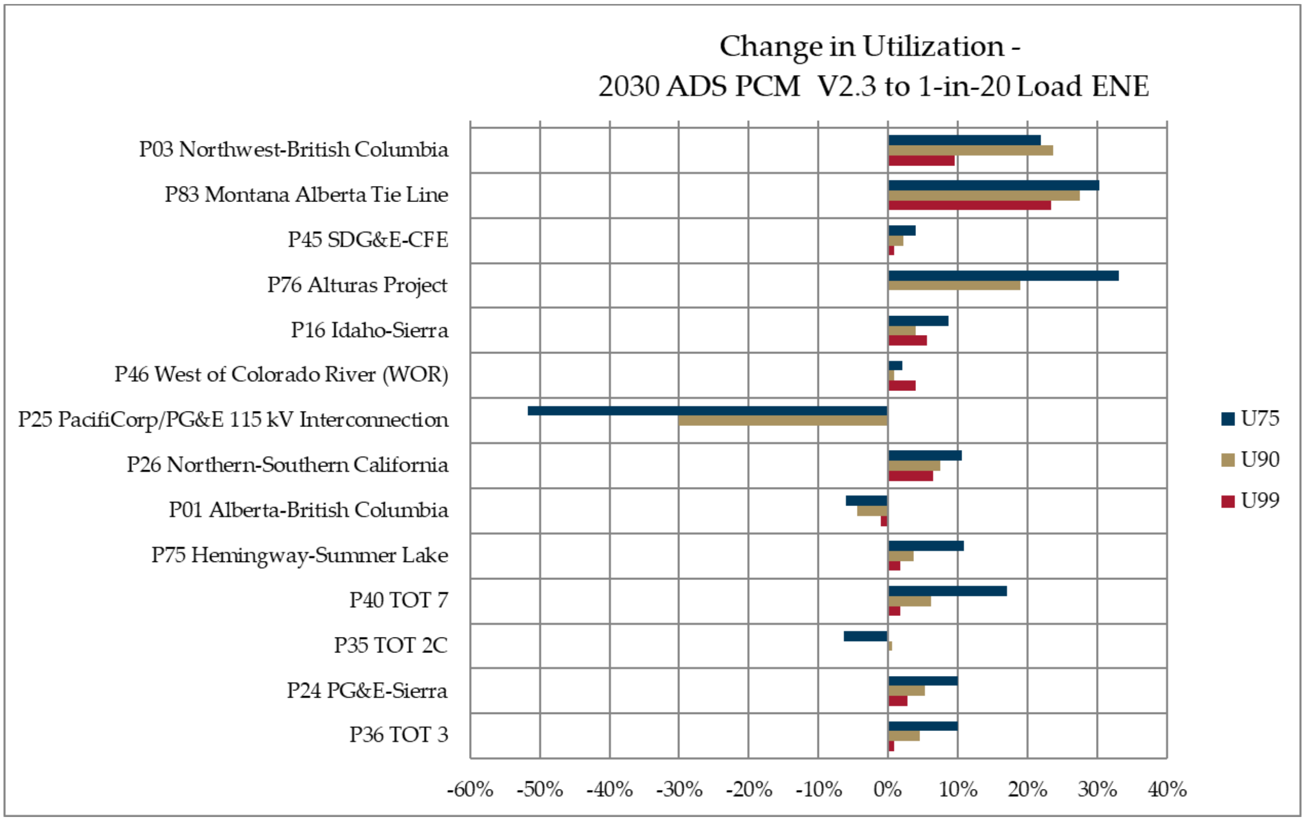

Figure 29 Changes in path utilization from 2030 ADS PCM case to 1-in-20 Load ENE case

Transmission Outages

In addition to the modeled extreme natural event, the assessment considered whether the seven sustained transmission outages (identified through processing TADS data), would affect unserved load, ancillary services, or path utilization. Adding the seven sustained transmission outages to the 1-in-20 Load ENE case did not significantly change the results for unserved load, ancillary service requirements, and Path utilization. Figure 30 compares the unserved energy for the 1-in-20 Load ENE case *with* outages to the 1-in-20 Load ENE case *without* outages and shows almost no change. Similarly, almost no change was observed in the amount of total unserved energy and number of hours of unserved energy for BAs between the two cases. These results are included in the appendix in Figure 34 and Figure 35.

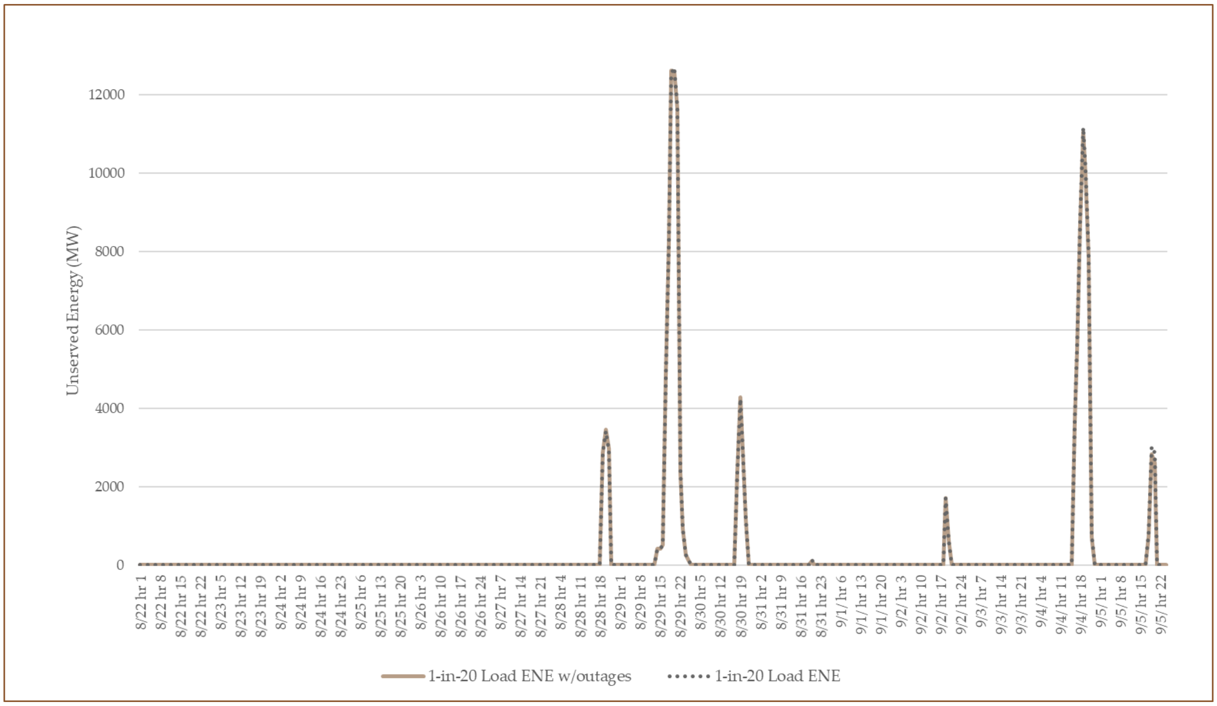

Figure 30: Unserved energy (MW) in 1-in-20 Load ENE case *with* outages and 1-in-20 Load ENE case *without* outages.

Figure 31 compares the number of hours of unmet spinning reserve for the 1-in-20 load case *with* outages to the 1-in-20 load case *without* outages. The BAs and reserve sharing groups that met requirements for spinning reserves for all hours were excluded from this figure. Overall, there was 2% increase in the number of hours in which spinning reserves were not met for the 1-in-20 Load ENE case *with* outages as compared to *withou*t outages. Similar results were observed for regulation up and load-following up, which had a 1% increase in the number of hours in which these ancillary services were not met for the case *with* outages as compared to *without* outages. There was no change in the results for regulation down and load-following down. These results are included in Figure 36 through Figure 38 in the appendix. The BAs that met requirements for ancillary services for all hours were excluded from these figures. These results indicate the seven sustained transmission outages affected the ability of the system to maintain required ancillary services; however, the impact was not significant.

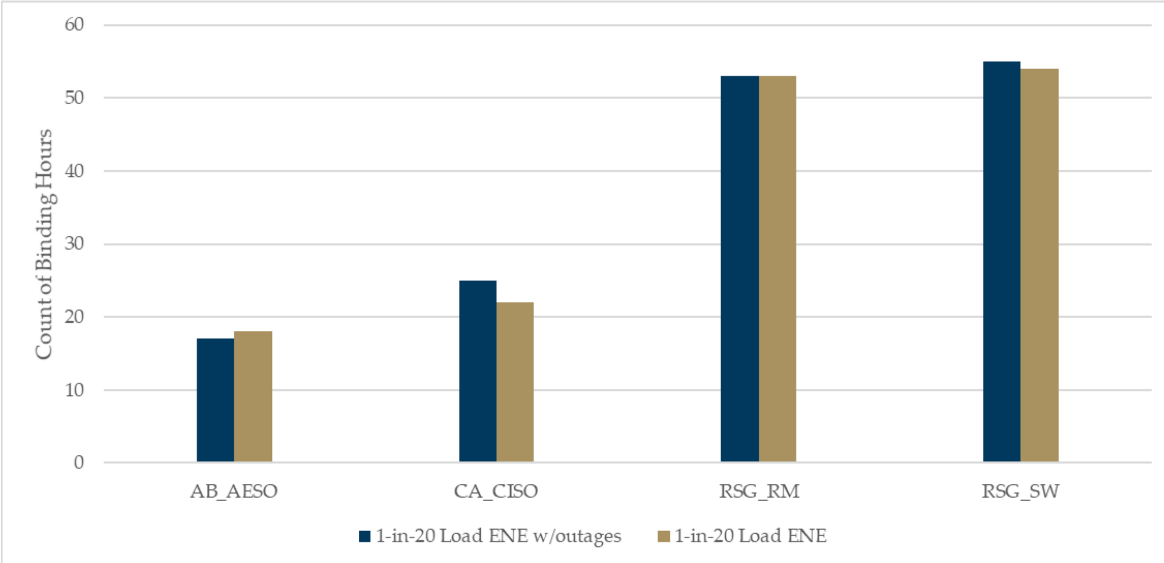

Figure 31: Hours of Unmet Spinning Reserve

Figure 32 shows the percentage change for Path utilization for the most heavily utilized Paths from the 1-in-20 Load ENE case *with* outages to the 1-in-20 Load case *without* outages. The results show less than 4% change in Path utilization, indicating these outages had little impact on Path use.

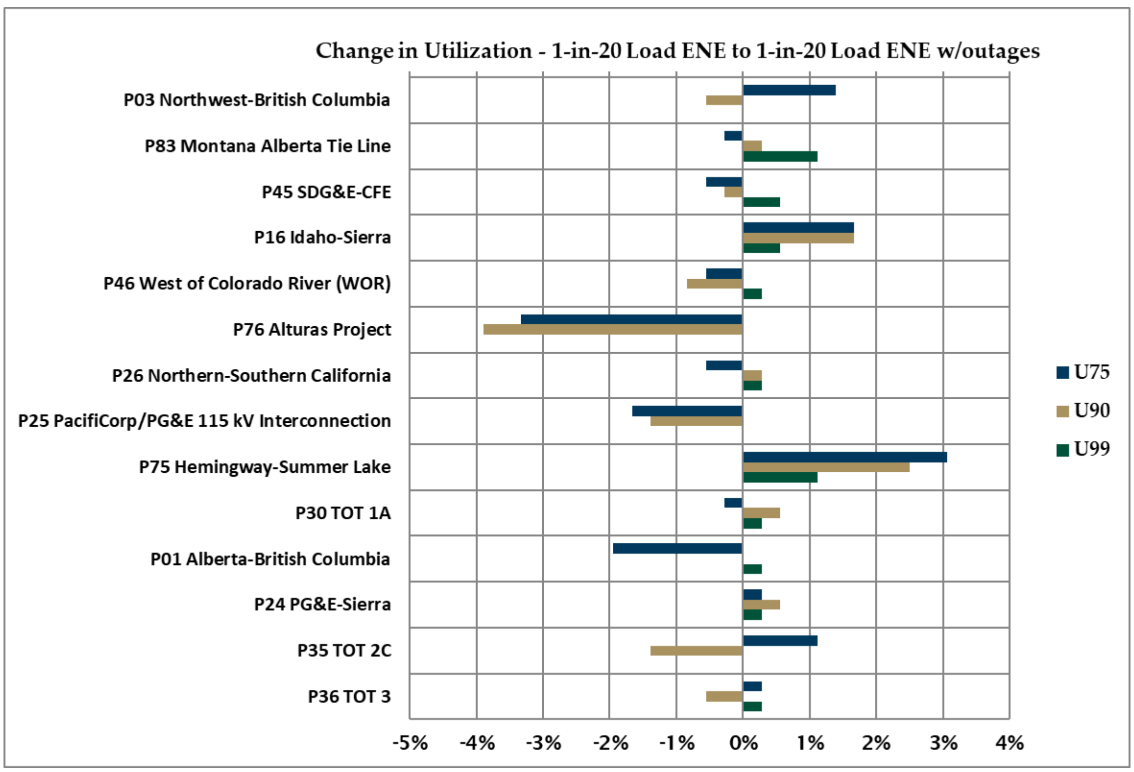

Figure 32: Changes in path utilization from 1-in-20 Load ENE case to 1-in-20 Load ENE case with outages

This demonstrates that the seven transmission outages studied did not significantly change the ability of the BPS to meet load, maintain ancillary service requirements, and affect utilization of paths more than what was observed due to the simulation of extreme heat, reduced hydro, and reduced solar generation already.

Conclusions

Stability and Dynamic Conclusions

This study showed the impacts on system stability when demand and resources change and when transmission is stressed, assuming the load can be served. The system response showed no concerns with regard to system stability. Load was automatically reduced in the simulations based on equipment response. However, no frequency delved below critical thresholds, and the system remained stable during studied frequency responses. Voltage fluctuations were observed in the simulations with the extreme conditions of reduced hydro, solar, and increased load (though, still in a localized region) and did not result in any systemwide instabilities during the simulations. Frequency and voltage responses changed when the weather conditions were applied, but stayed within acceptable performance thresholds.

Production Cost Model Conclusions

Based on the analysis above, the following conclusions were drawn:

- In the modeled extreme natural event, it was observed that many regions experienced unserved energy, especially during shoulder hours when solar production was ramping down.
- During the modeled extreme natural event, multiple regions did not meet the ancillary service requirements for spinning reserves, regulation up and down, and load-following up and down for higher number of hours as compared to 2030 ADS PCM.
- During an extreme natural event such as the one modeled in this assessment, it is likely that less energy might be available for export from neighboring regions. Grid operators may not be able to rely on imports to meet energy and ancillary service requirements.
- Interregional transmission flows and some individual Path flows may approach rated limits during an extreme event. Although there did not appear to be additional impacts to reliability due to Path utilization, additional studies may be warranted to assess the impacts of increased flows on selected high-utilization Paths.
- The seven sustained outages evaluated in this assessment did not significantly affect unserved load, ancillary service deficiencies, and changes in path utilizations otherwise experienced during the extreme natural event.

Recommendations

WECC provides the following recommendations based on its observations of the results of this assessment:

- Planning entities in the Western Interconnection should evaluate the risk of unserved energy during extreme events as part of planning studies considering both load and generation.
- Planning and operating entities should consider further analysis of reserves and ramping requirements to withstand extreme events.
- Planning and operating entities should consider extreme events when performing in-depth studies related to transmission congestion.
- Transmission planners should consider simulating compounded extreme weather events, such as simultaneous drought and heat wave, in planning studies and monitor system voltage performance.
- WECC's Reliability Assessment Committee (RAC) should discuss and coordinate the availability of extreme natural event assumptions and data being used for reliability assessments.

Contributors

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**Employed by WECC at time of authorship.*

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Appendices

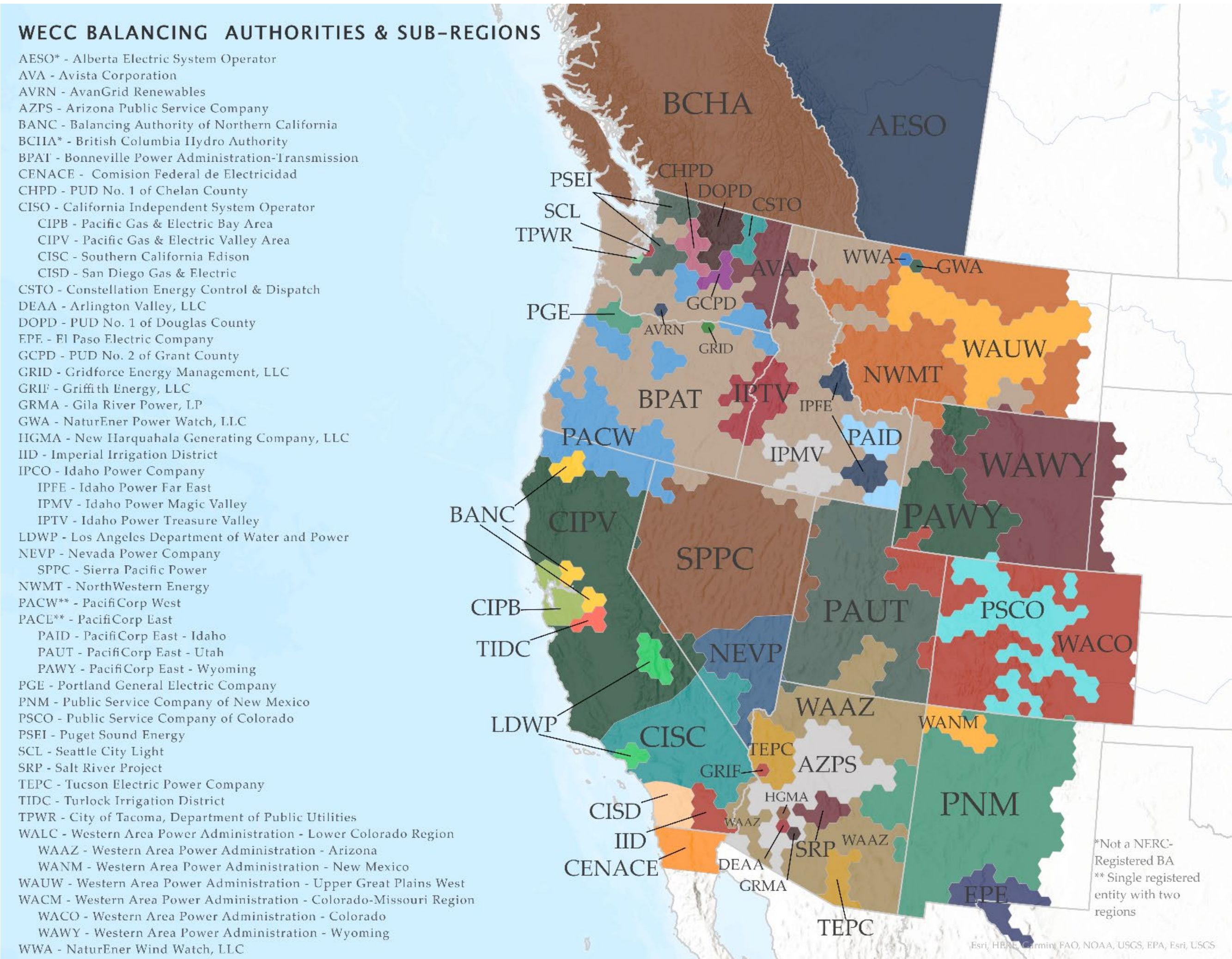

Figure 33: Boundaries of Balancing Authority Areas

Table 5: Balancing Authorities—Abbreviations and names

Abbreviation	Balancing Authority Name
AB_AESO	Alberta—Alberta Electric System Operator
BC_BCHA	British Columbia—British Columbia Hydro
BS_IPCO	Basin—Idaho Power Company
BS_PACE	Basin—PacifiCorp East
CA_BANC	California—Balancing Authority of Northern California
CA_CFE/CENACE	California—Comisión Federal de Electricidad
CA_CISO	California—California Independent System Operator

Abbreviation	Balancing Authority Name
CA_IID	California—Imperial Irrigation District
CA_LDWP	California—Los Angeles Department of Water and Power
CA_TIDC	California—Turlock Irrigation District
NW_AVA	Northwest—Avista Corporation
NW_BPAT	Northwest—Bonneville Power Administration-Transmission
NW_CHPD	Northwest—PUD No. 1 of Chelan County
NW_DOPD	Northwest—PUD No. 1 of Douglas County
NW_GCPD	Northwest—PUD No. 2 of Grant County
NW_NWMT	Northwest—Northwestern Energy
NW_PACW	Northwest—PacifiCorp West
NW_PGE	Northwest—Portland General Electric Company
NW_PSEI	Northwest—Puget Sound Energy
NW_SCL	Northwest—Seattle City Light
NW_TPWR	Northwest—City of Tacoma, Department of Public Utilities
NW_WAUW	Northwest—Western Area Power Administration, Upper Great Plains West
RM_PSCO	Rocky Mountain—Public Service Company of Colorado
RM_WACM	Southwest—Western Area Power Administration, Colorado-Missouri Region
SW_AZPS	Southwest—Arizona Public Service Company
SW_EPE	Southwest—El Paso Electric Company
SW_NVE	Southwest—Nevada Energy
SW_PNM	Southwest—Public Service Company of New Mexico
SW_SRP	Southwest—Salt River Project
SW_TEPC	Southwest—Tucson Electric Power Company
SW_WALC	Southwest—Western Area Power Administration, Lower Colorado Region

Table 6: Inter-region transfer for 1-in-20 Load case as compared to 2030 ADS PCM V 2.3

	1-in-20 Load ENE (GWh)	2030 ADS PCM V 2.3 (GWh)	% Change
British Columbia -> Alberta	69	242	-71%
British Columbia -> Northwest	622	1178	-47%
Alberta -> Northwest	60	27	122%
East -> Northwest	2	4	-50%
Basin -> Northwest	500	658	-24%
Rocky Mtn -> Northwest	21	81	-74%
Rocky Mtn -> Basin	68	200	-66%
Rocky Mtn -> East	44	88	-50%
Rocky Mtn -> Southwest	14	240	-94%
Southwest -> Basin	17	-176	-110%
Northwest -> CA/MX	94	1040	-91%
Basin -> CA/MX	255	320	-20%
Southwest -> CA/MX	2,720	2781	-2%
East -> Southwest	0	0	0%

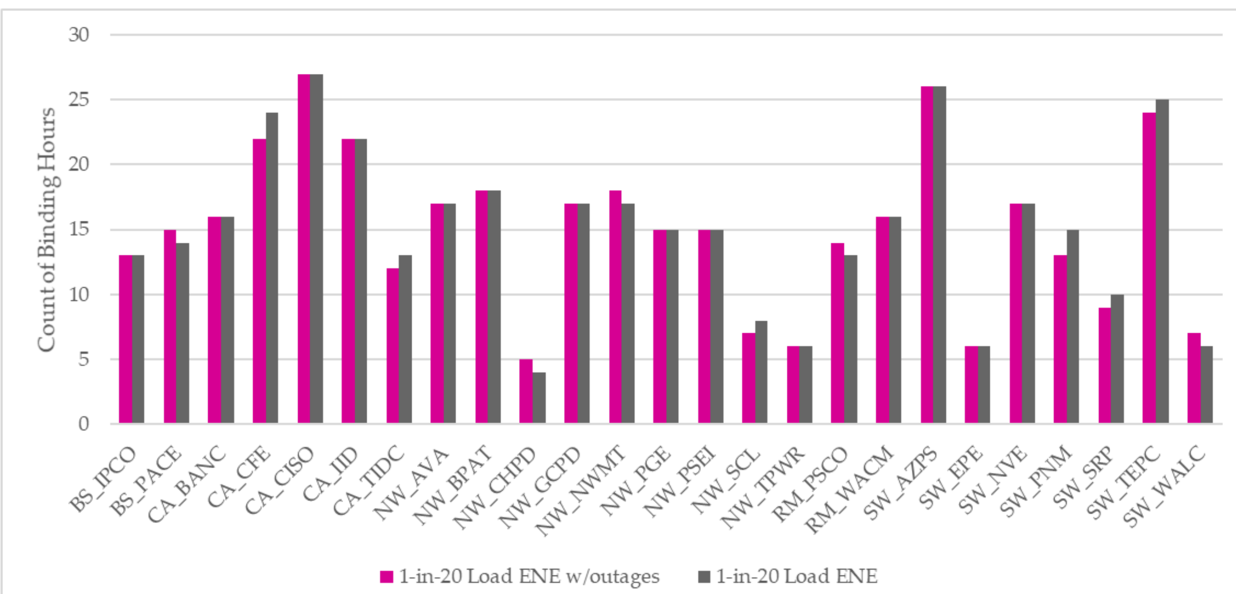

Figure 34: Hours of unserved energy by region for 1-in-20 case with and without outages

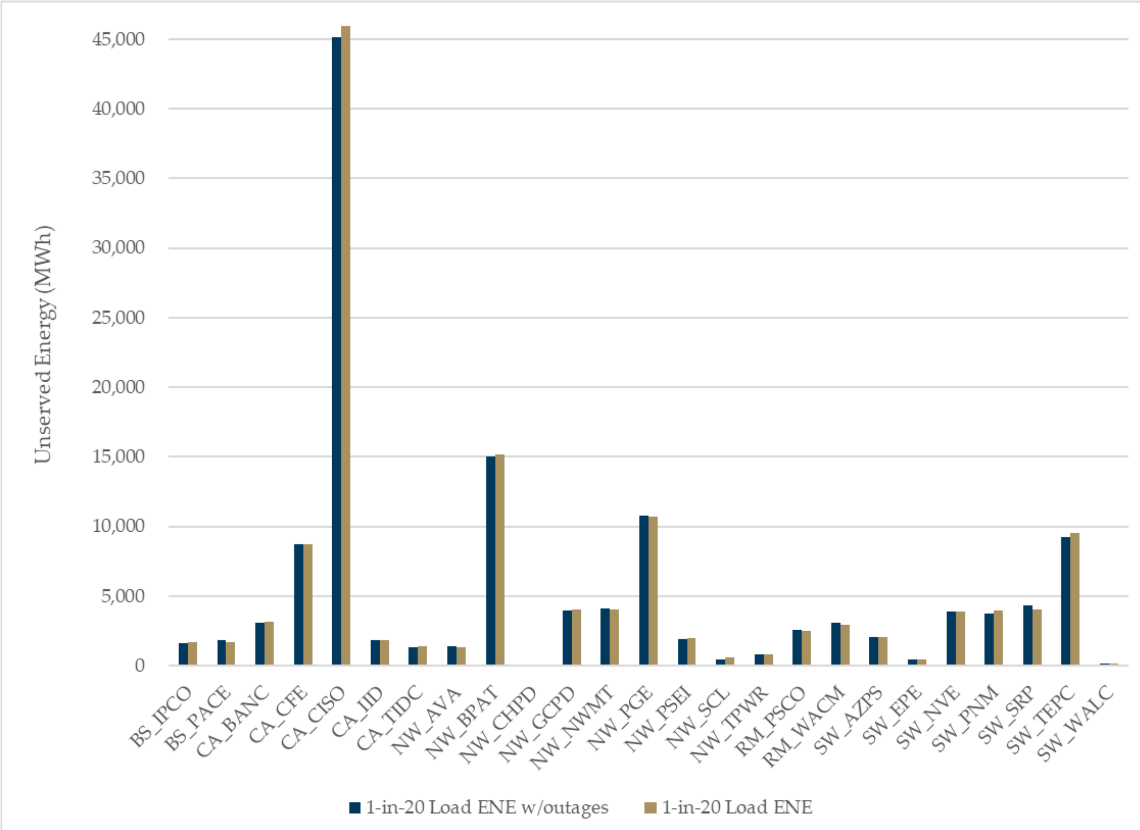

Figure 35: Unserved energy (MWh) by region for 1-in-20 load case with and without outages

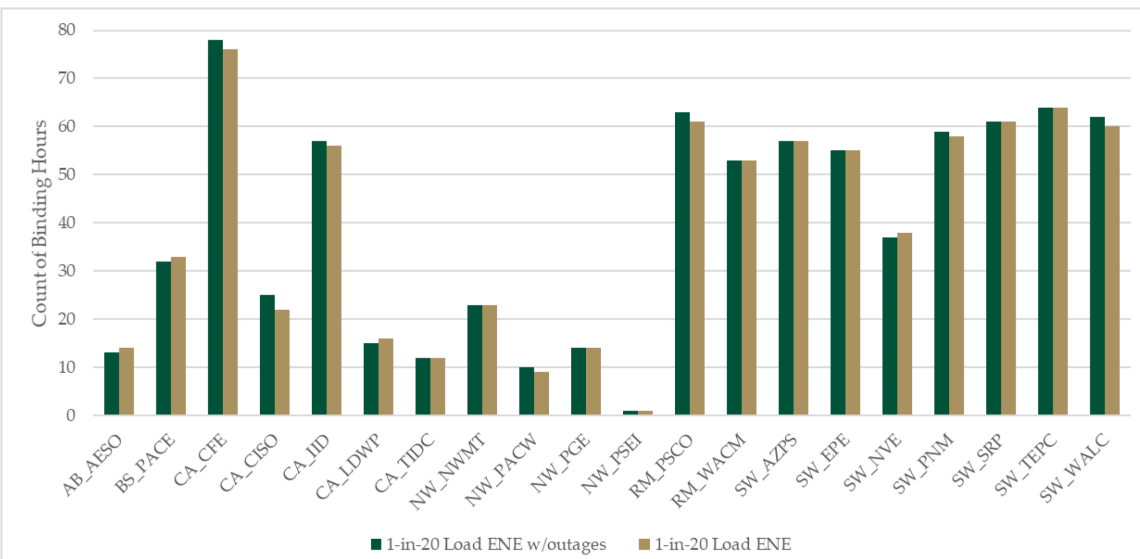

Figure 36: Hours of unmet regulation up by BA

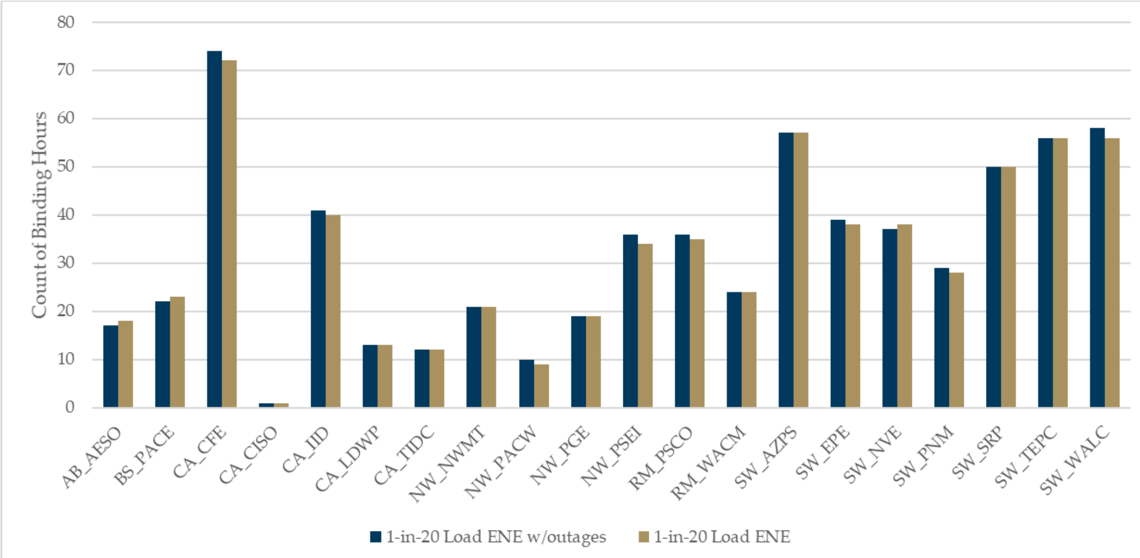

Figure 37: Hours of unmet load-following up by BA

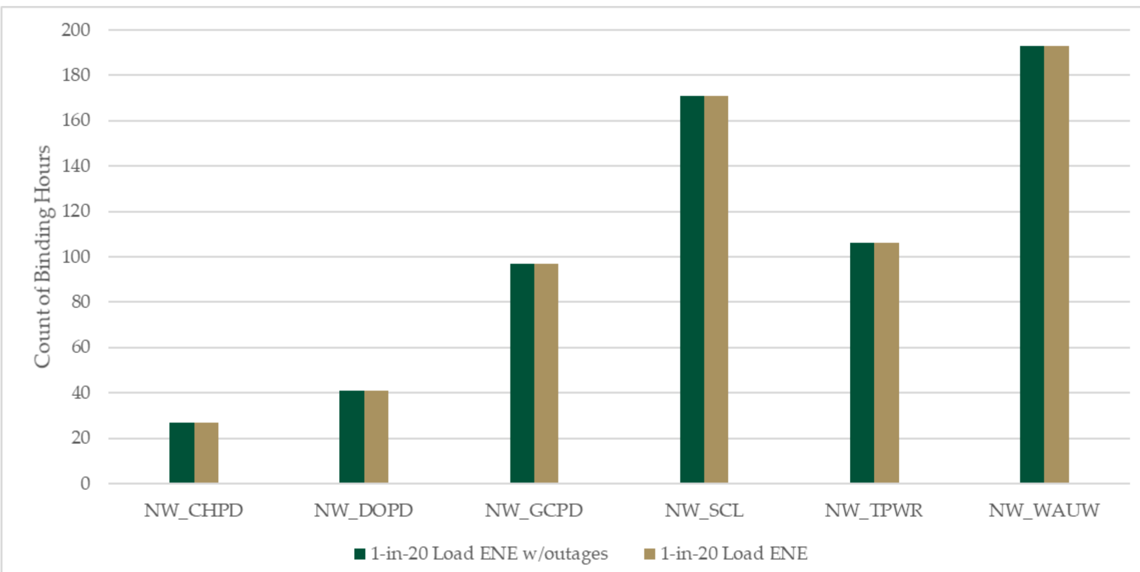

Figure 38: Hours of unmet regulation down or load-following down by BA