



System Resilience Under Extreme Natural Disaster

January 8, 2020

Executive Summary

The purpose of this assessment is to evaluate the impact of an extreme natural disaster on the reliability of the Bulk Electric System (BES) in the Western Interconnection (WI). Given that the WI experiences extreme disasters somewhat regularly, such as yearly wild fires and occasional extreme earthquakes, this assessment is designed to identify challenges to the resilience of the WI and to help transmission providers plan accordingly.

The scope of this assessment includes studying the impact on WI system adequacy and system stability within a Year 10 future in an Extreme Event caused by California wild fires. This case study was inspired by California's Tucker Wild Fire in July 2019. The assessment used WECC's 2028 Anchor Data Set (ADS) planning cases to model a Production Cost Model (PCM) analysis using ABB's GridView software and a Power Flow (PF) Model analysis using GE's PSLF software. To identify a highly stressed system condition, the assessment started with the ADS 2028 PCM Phase 1 V2.2, and identified August 7, 2028, Hour 20 (08/07/2018 Hr. 20) as the hour when Path 66 (COI) and Path 65 (PDCI) were most heavily loaded, and the danger of fire was highest. The generation dispatch and load for the 08/07/2028 Hr. 20 were extracted from the 2028 ADS PCM Phase 1 V2.2 and used as input for the 2028 Heavy Summer 1 base case to create a PF case for the assessment. Assumptions for contingencies on major transmission path P66 COI were added to both cases. For the PCM case, the Extreme Event was assumed to last seven days following the contingency and the system was evaluated for resource adequacy, unserved energy, reserve margins, generation mix, inter-region transfers, path utilization, and path flows. The PF case looked at transient and voltage stability of the WI system following the hour of contingency.

Under COI outage conditions, the system was found to have adequate resources and no unserved energy. Some of the paths had higher utilization due to change in inter-regional flows. There was a 25% reduction in energy imported into the California region requiring higher production of resources (combined cycle and combustion turbine) to compensate. The current WI was not able to adequately transfer renewable generation outside California under this outage condition. The system maintained transient and voltage stability after the outage event occurred.

The task force managing this assessment recommends:

- Continuing this study in the future to evaluate the adequacy and stability of the interconnection under more scenarios of extreme natural disaster;
- Seeking partnership with other entities to help identify more diverse scenarios to evaluate the system; and
- Aligning this study more appropriately with the ADS planning case building cycle to use the most current data and assumptions.



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1. Introduction

The purpose of this study is to evaluate the impact of an extreme natural disaster on the reliability of the Bulk Electric System (BES) in the Western Interconnection (WI) in a Year 10 future. The WI experiences extreme natural disasters such as yearly wild fires and, occasionally, extreme earthquakes. As a case study, this assessment will investigate a wild fire in western California that is made more extreme due to high winds. This assessment helps to identify possible challenges to the resilience of the WI and is intended to help transmission providers consider them in future planning studies.

This study analyzed the resource adequacy and stability of the WI in a Year 10 future resulting from a wild fire in California based on the real Tucker fire in July 2019. Reliability risks to the BES in the WI that were analyzed are:

- Unserved energy,
- Flows and utilization on major transmission paths,
- Spillage of renewable resources,
- Load-generation balance,
- Reserve margin,
- Inter-region transfer, and
- Transient and voltage stability.

2. Participants

The following people were members of the Extreme Natural Disaster Task Force (ENDTF) that led this assessment:

Name	Organization
Bhavana Katyal—Staff Liaison	WECC
Tyson Niemann—Staff Liaison	WECC
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3. Assessment Approach

The assessment required two parallel tracks, using two different modeling tools, to answer the following questions:

Q1: How does the extreme natural disaster impact the transient and voltage stability of the WI system following the hour of contingency?

Tool Used: A power flow model using GE's PSLF software was used to create a Year 10 case consistent with the Year 10 PCM case for the hour of contingency to analyze these questions.

Q2: How does the modeled extreme natural disaster impact the resource adequacy and transmission path utilization for a seven-day period starting with the hour of contingency in the WI?

Tool Used: WECC used a PCM, which used ABB's GridView software to analyze these questions.

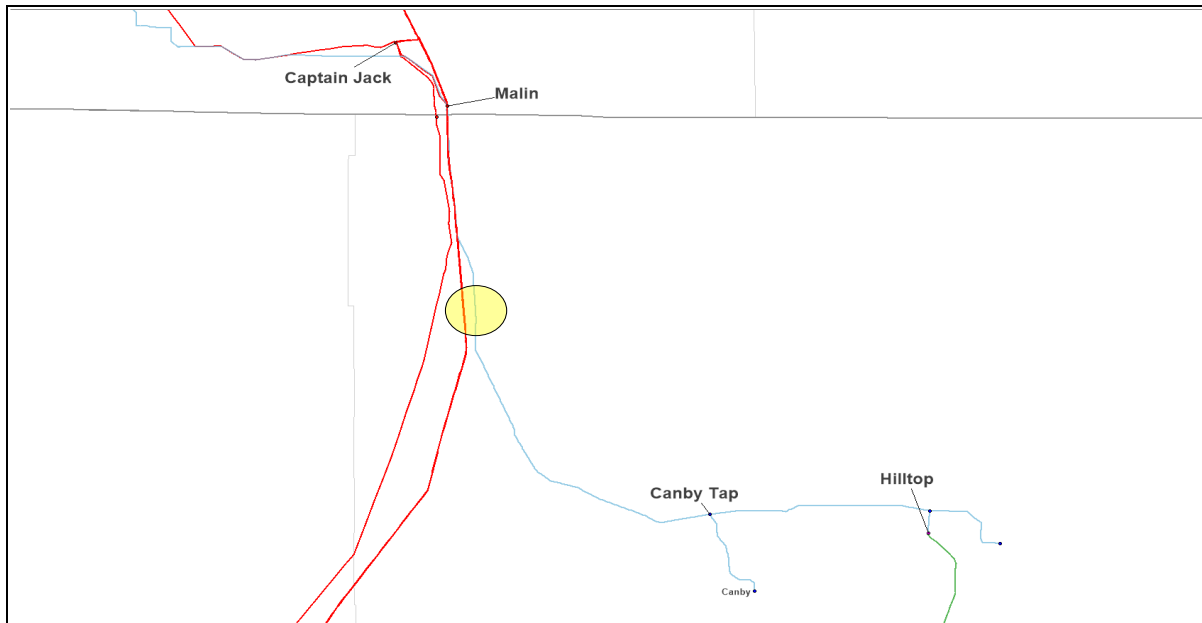
3.1. Assumptions

The ENDTF developed a scenario based on the Tucker fire in California that began in July 2019 to model this assessment.

Background on Tucker Fire:

The Tucker Wild Fire began on July 28, 2019, in California. The fire, as shown in Figure 1, was near the Malin-Round Mt. 500-kV right of way (ROW). According to the Bonneville Power Administration (BPA) outage log, on July 28 the Malin-Round Mt. 500-kV line #2 relayed and reclosed at 16:38 and the Malin-Canby-Hilltop 230-kV line relayed and reclosed at 17:19. Both lines reclosed successfully and did not trip.

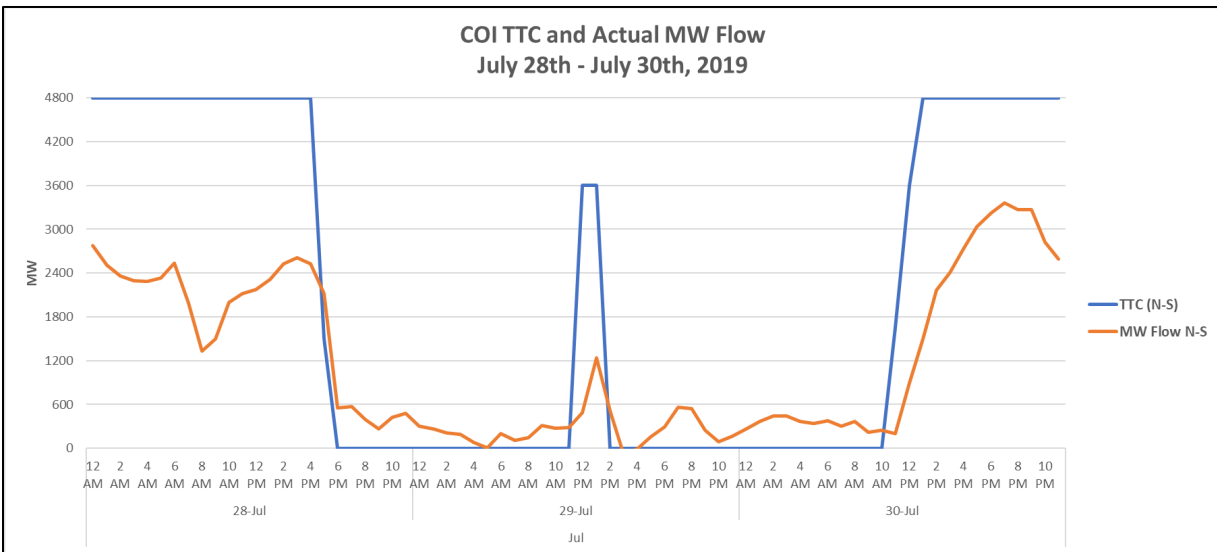
Figure 1: Tucker Wild Fire Location



With the fire's proximity to the Malin-Round Mt. 500-kV ROW, the U.S. Forest Service requested that the Malin-Round Mt. 500-kV lines 1 and 2 be de-energized as a precaution for firefighting personnel on the ground. The lines were successfully de-energized at approximately 18:00 on July 28, 2019. The fire moved northeast toward the Malin-Hilltop 230-kV ROW and away from the Captain Jack-Olinda 500-kV ROW. As such, the Captain Jack-Olinda 500-kV line remained energized, as it did not present the same safety concerns as the adjacent 500-kV lines.

To prepare for the potential outage of the Captain Jack-Olinda 500-kV line, the COI Total Transfer Capability (TTC) was reduced to zero during this period. Figure 2 shows the COI TTC and COI actual MW flow from July 28 to 30. The actual COI flow while the COI TTC was set to zero represents the unscheduled flow over the remaining Captain Jack-Olinda 500-kV line, which reached a maximum of about 600 MW north-to-south (N-S).

Figure 2: COI TTC and Flows for Jul 28-30, 2019



Scenario for Study Assessment

The extreme natural disaster scenario in this assessment is a fictional fire in northern California based loosely on the Tucker fire that occurred in July 2019. The fire is assumed to be in the same area as the Tucker fire, but, unlike the Tucker fire, will cause the nearby 500-kV lines and 230-kV lines to trip.

The outages created for the scenario include two main events:

1. Simultaneous outage of the Malin-Round Mt. 500-kV lines and the Malin-Hilltop 230-kV line; and
2. Following system adjustment, the outage of the Captain Jack-Olinda 500-kV line.

The outage of the transmission facilities simulated in the two events were then assumed to be out of service for seven days.

Post-Transient Power Flow and Transient Stability Analysis

Post-transient power flow and transient stability analysis was performed to identify any potential reliability concerns caused by the two main outage events of the scenario. For additional margin, the COI N-S flow was increased to 4,800 MW from the 4,620 MW N-S represented in the PCM before simulating the first outage event. The COI N-S flow was then reduced to 600 MW before simulating the second outage event. Path 76 N-S flows were not manually reduced but were about zero following the loss of the Malin-Hilltop 230-kV line.

Further details of the two outage events and relative pre-contingency conditions are shown in Table 1.

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Table 1: Transfer Into Regions

Outage Event	Pre-Contingency Conditions		Outage Description
	Transmission	Path Flows (N-S)	
1	All-lines-in	COI 4,800 PDCI 2,780 Path 76 171	Malin-Round Mt. 500-kV Line 1 and 2 Malin-Hilltop 230-kV line
2	Malin-Round Mt. 500-kV Line 1 and 2 Out Malin-Hilltop 230-kV line Out	COI 600 PDCI 2,780 Path 76 0	Captain Jack-Olinda 500-kV line

Resource Adequacy Analysis

For the resource adequacy analysis, the outages of transmission facilities in the two main outage events were assumed to be out of service for seven days. During the outages, COI was reduced to zero and Path 76 was reduced to about zero. The transmission facilities assumed out of service for the seven-day period include the following:

1. Malin-Round Mt. 500-kV lines 1 and 2 out of service
2. Malin-Canby-Hilltop 230-kV line out of service
3. Captain Jack-Olinda 500-kV line out of service

3.2. Data and Procedure

The ENDTF used the 2028 Anchor Data Set (ADS) Planning Cases as a starting point to model the scenarios. The PF case was modified version of the 2028 Heavy Summer 1 base case and the PCM case was a modified version of 2028 ADS PCM Phase 1 V2.2.

The assessment evaluated the periods during which the flows were at their highest on transmission paths P66 COI and P65 PDCI in the ADS PCM case. There were several periods throughout 2028 during which flows on COI and PDCI were near their maximums. The task force selected August 7, 2028, Hour 20, since fire danger is highest during the summer. The system conditions in the ADS PCM case at 08/07/2028 Hr. 20 are shown below.

Table 2: Path 66 and 65 Flows on 08/07/2028 Hr. 20

8/7 Hour 20	MW Flow
COI	4,620
PDCI	2,780

The generation dispatch and load from Hr. 20 were extracted from the PCM and used to change the 2028 Heavy Summer 1 base case to create a power flow case for the assessment. There were small differences due to the way PSLF and GridView calculate losses. These losses were accounted for in the power flow by scaling down the total load by 1,021 MW throughout the case.

Assumptions for scenarios from section 3.1 for each case were added to the PCM and PF cases to build the cases under disaster conditions and are referred to collectively as the “COI outage” case in this report. For the PCM case an outage of seven days was evaluated starting at the hour of contingency, 08/07/2028 Hr. 20, and ending at 08/14/2028 Hr. 24. This is referred to as the “outage period” in this report.

4. Production Cost Model Results

4.1. Interregional Transfers

Tables 3 and 4 show the percentage change in net flow (GWh) into a region and inter-regional transfers, respectively, for August 8 through 14, 2028. Figures 3 and 4 show the regional transfer in the WECC footprint for the ADS PCM case and the COI outage case, respectively, for August 8 through 14, 2028. The following are the key observations:

1. During the COI outage, there are reduced imports overall into California. The imports into California from the Northwest are reduced by 54%; from Basin reduced by 11%, and from the Southwest reduced by 7%. The net reduction in imports into the California region is 25%.
2. During the COI outage, the Northwest region supplies to Basin instead of importing from Basin, as in the ADS PCM case. There is an 85% reduction in net import to the Northwest region with the COI outage.

Table 3: Transfer Into Regions

	Transfers In (GWh) ADS 2028 Ph 1 V 2.2	Transfer in (GWh) COI outage	% Change
Alberta	88	94	6.8%
BC	-267	-266	-0.4%
Northwest	301	45	-85.0%
Basin	-426	-256	-39.9%
Rocky Mtn	-144	-128	-11.1%
CA/MX	1668	1254	-24.8%



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Southwest	-816	-577	-29.3%
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Table 4: Inter-Regional Transfers

	Inter-Regional Transfers (GWh) ADS 2028 Ph 1 V 2.2	Inter-Regional Transfers (GWh) COI outage	% Change
BC -> Alberta	66	75	13.6%
BC -> Northwest	201	191	-5.0%
Northwest -> Alberta	22	19	-13.6%
Northwest -> Basin	-108	133	-223.1%
Northwest-Rocky Mtn	13	21	61.5%
Northwest-CA/MX	614	282	-54.1%
Basin-CA/MX	184	164	-10.9%
Rocky Mtn-Basin	47	15	-68.1%
Basin-Southwest	87	240	175.9%
Rocky Mtn-Southwest	93	117	25.8%
Southwest-CA/MX	870	808	-7.1%

Figure 3: Inter-Regional Flows—ADS PCM Case

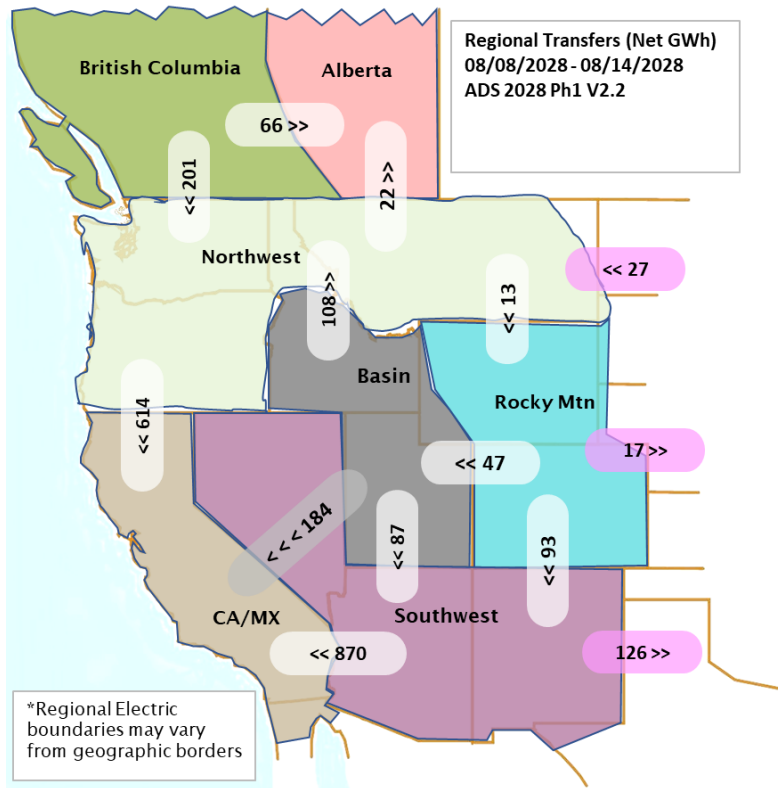
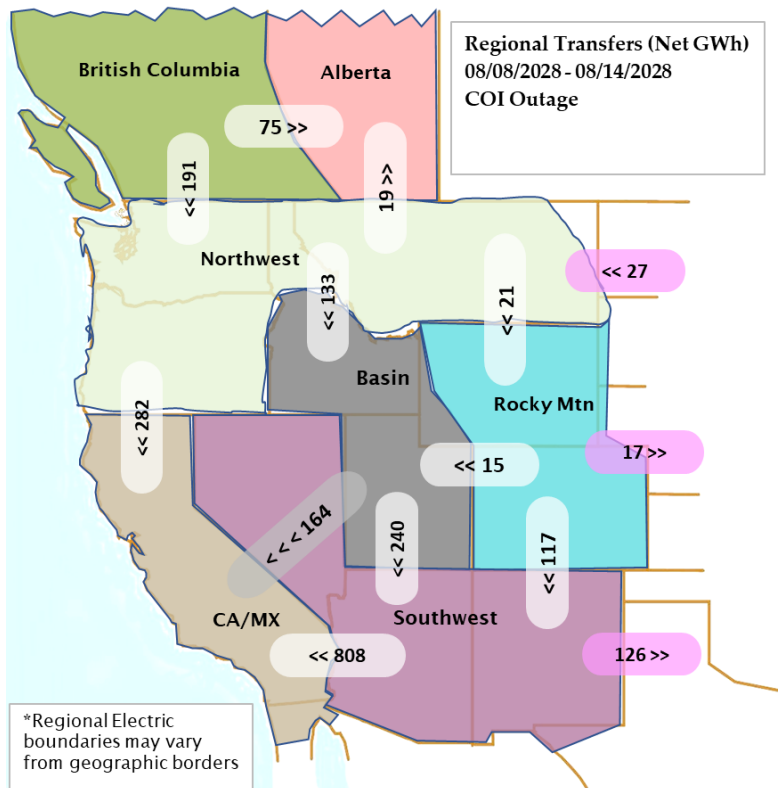


Figure 4: Inter-Regional Flows—COI Outage

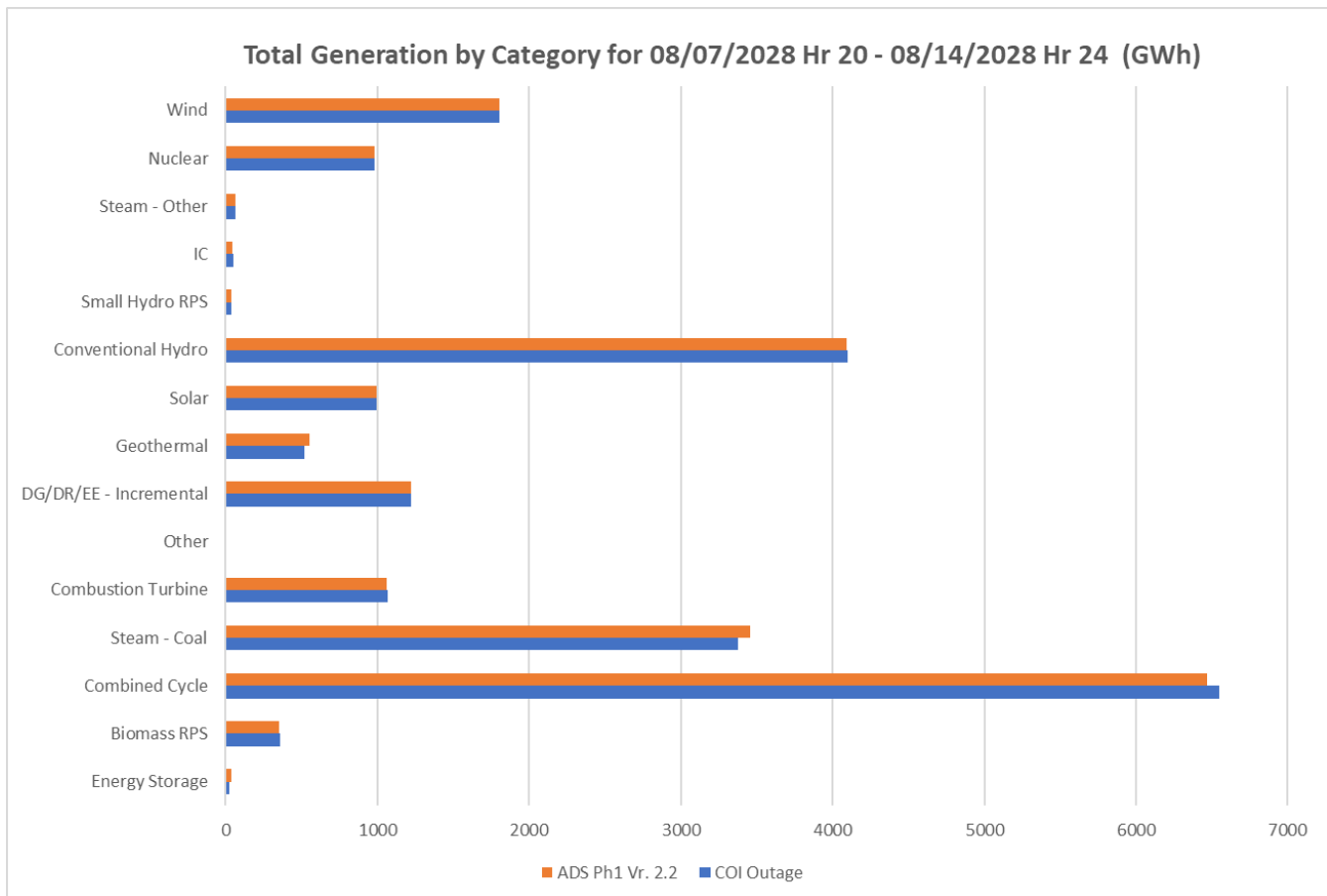


4.2. Generation Mix and Load—Energy Balance

The ENDTF evaluated the impact of the COI outage on generation mix to see which resources become more important to meet the system demand during this Extreme Event. Figure 5 compares the total generation from the ADS PCM case to the COI outage. Figure 6 shows the percentage change in total generation by each resource type for the WI for the outage period. The ENDTF observed:

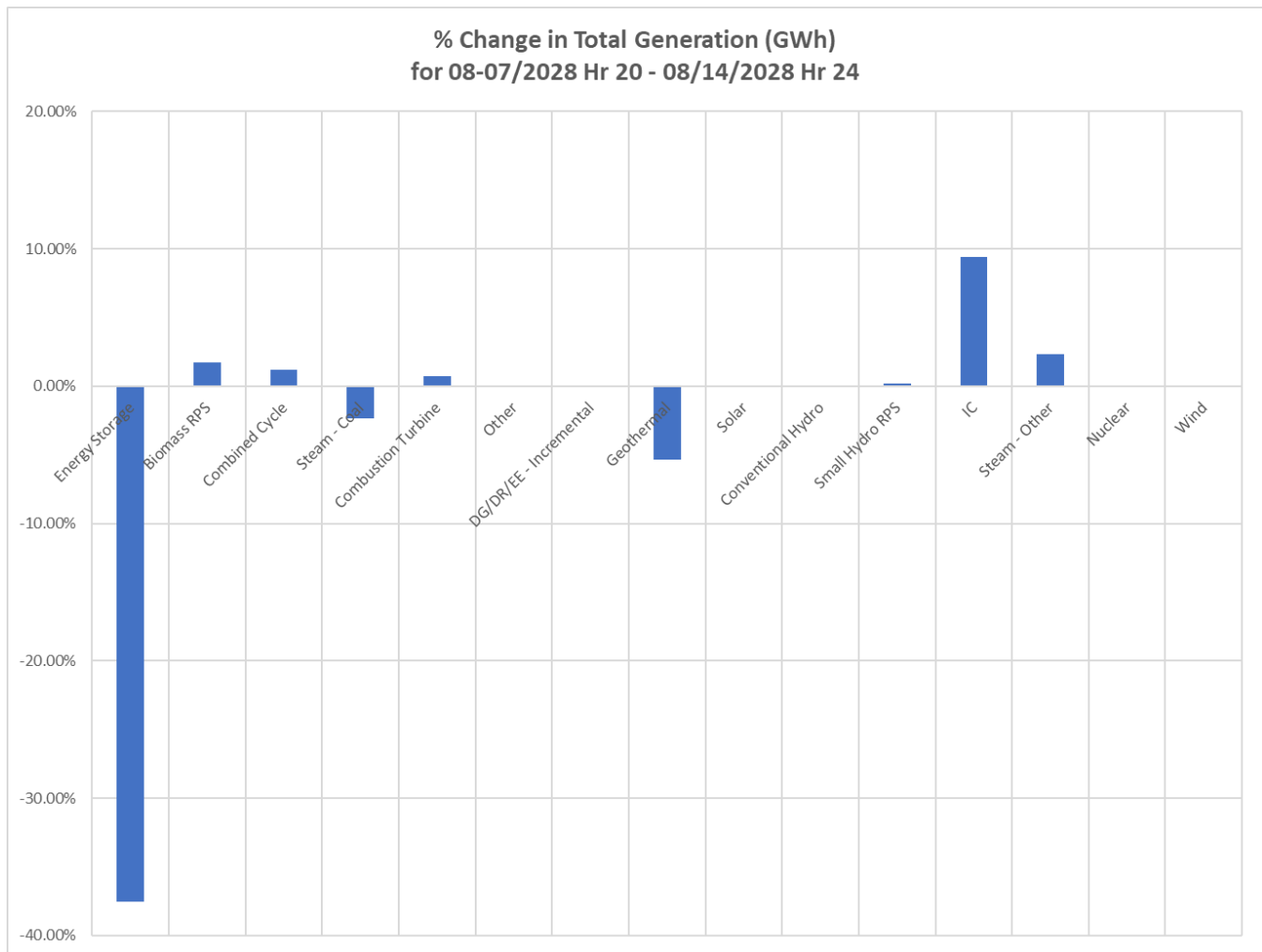
1. Under the COI outage, relative to the ADS 2028 Phase 1 V2.2, there is higher unitization of certain resource types—internal combustion (IC) engine, biomass, combined cycle, combustion turbine, hydro Renewal Portfolio Standards (RPS), and steam.
2. Also, with the COI outage, there is lower use of other resource types—energy storage, steam-coal, and geothermal. There is a significant decrease in the percentage of unitization of energy storage, but the GWh amount is fairly small.

Figure 5: Total Generation Aug 7-14, 2028 from ADS PCM Case to COI Outage



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Figure 6: Percentage Change in Tot Generation from ADC PCM case to COI Outage



The task force evaluated other effects of the COI outage on the California. The load-energy balance for California was evaluated to see how the load is being met during the outage, whether there is any unserved energy, and what was the resource mix needed to meet the demand. Figure 7 and Figure 8 shows the load-energy balance for California during the outage period. Figure 9 and Figure 10 shows the generation mix for the peak hour of production during the outage period at 8/9/2028 Hr. 17 for the California area. The ENDTF observed the following for the COI outage:

1. There is increased production of certain resource types including combined cycle, combustion turbine and hydro.
2. There is slight decrease in production of resource type DG/DR/EE, solar, wind, geothermal and nuclear.
3. In both the ADS PCM case and the COI outage, the internal generation available to serve California is not sufficient to meet load, thus leading to required imports.

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4. With the additional imports, California would be able to avoid unserved energy during the modeled extreme natural disaster.

Figure 7: California Energy-Load Balance—ADS PCM Case

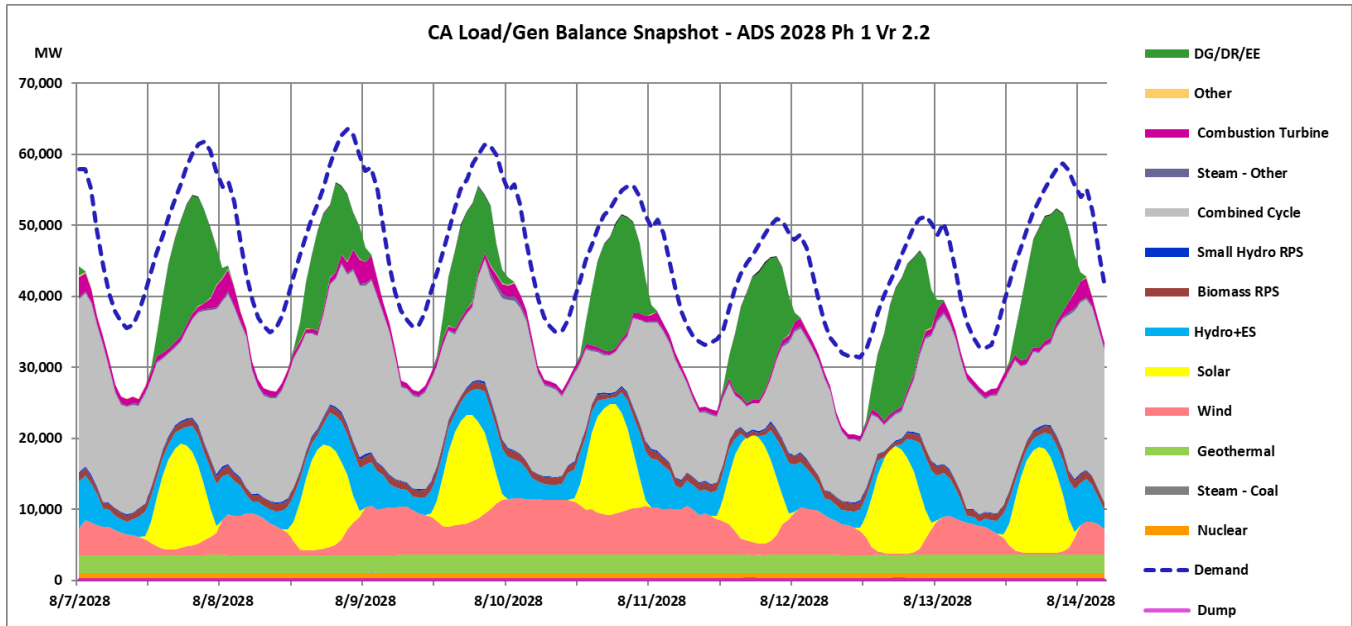
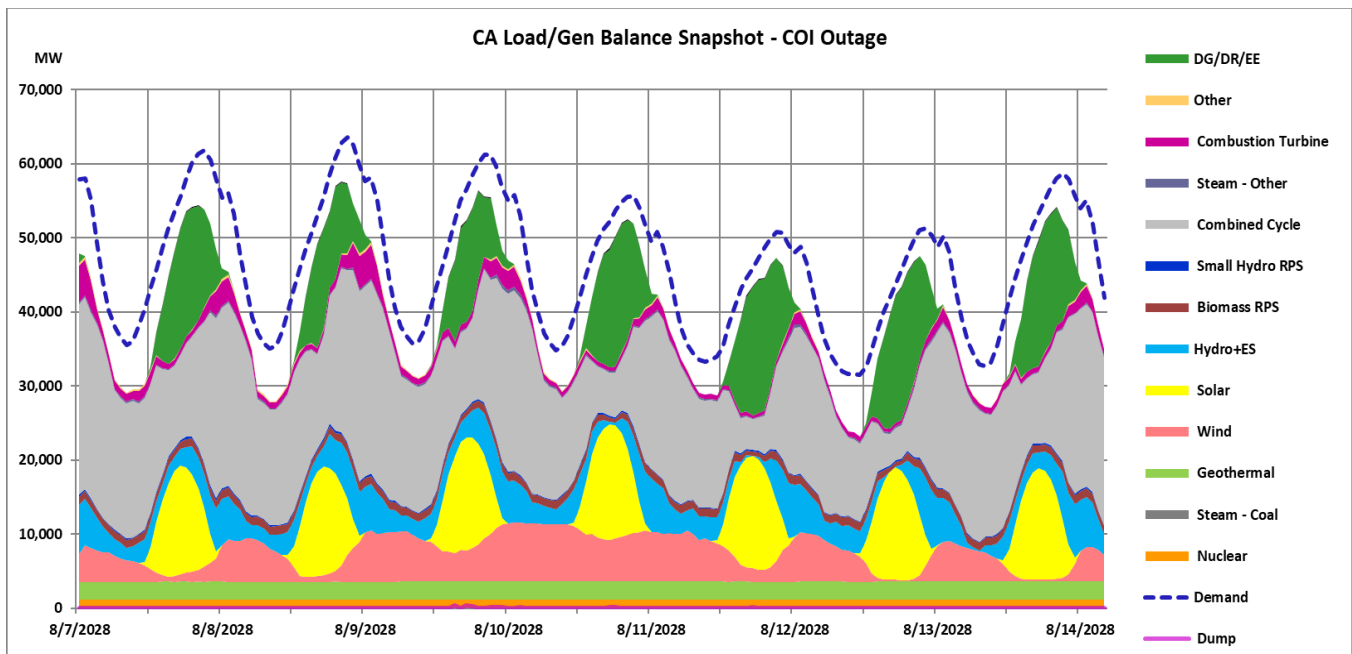


Figure 8: California Energy-Load Balance—COI Outage



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Figure 9: Peak Hour Generation for ADS PCM Case

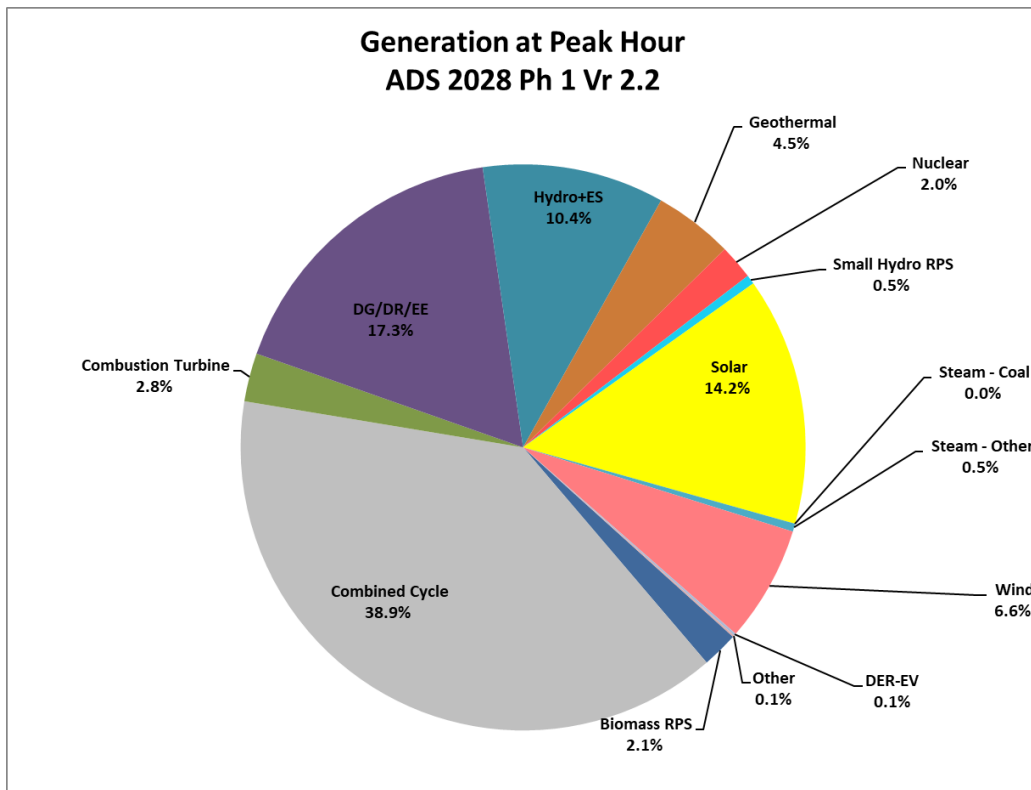
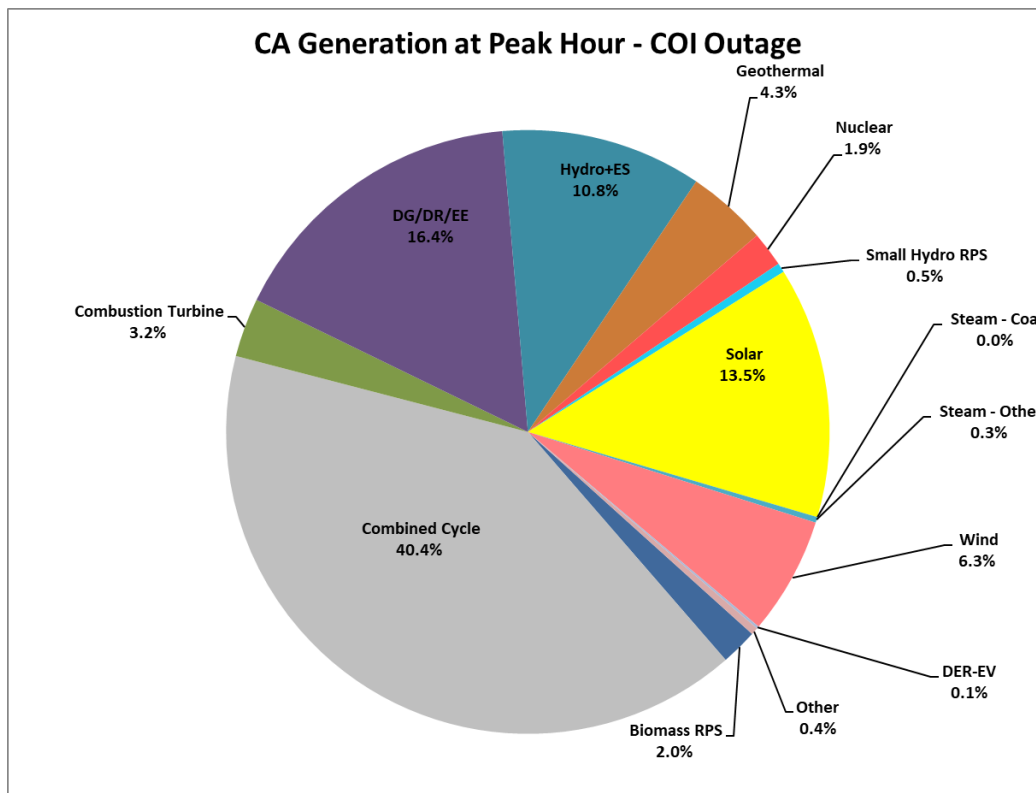


Figure 10: Peak Hour Generation for COI Outage

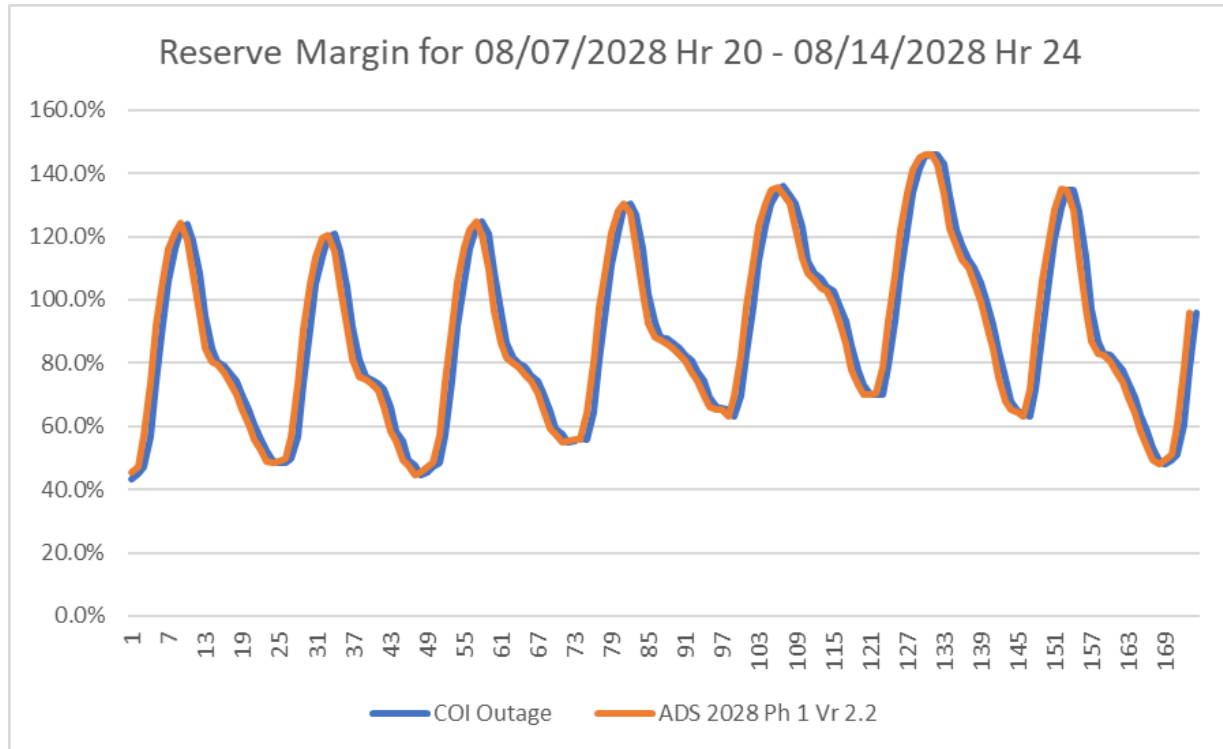


4.3. Unserved Energy and Reserve Margins

There was no unserved energy in the COI outage case and enough reserve margin for the system to ride the outage for the outage period. Figure 11 shows the reserve margins for ADS PCM case and COI outage. The reserve margin was defined as:

$$\text{Reserve Margin} = \frac{\text{Available Capacity} - \text{Served Load} - \text{Unserved Load}}{(\text{Served Load} + \text{Unserved Load})} \%$$

Figure 11: Reserve Margin for ADS PCM Case and COI Outage



4.4. System Spillage

Figure 12 compares the spillage by area before and after the COI outage. Spillage refers to the amount of resources, such as wind and solar, that cannot be dispatched to meet load due to transmission or other modeling constraints in a PCM model. Spillage is for dispatchable resources such as wind and solar. Figure 13 describes the areas modeled in the case. The areas in Figure 12 had zero spillage for the outage duration. Figure 12 shows—

1. There is higher spillage under COI outage conditions for the Los Angeles Department of Water and Power (LDWP), Northwest Montana (NWMT), Sierra Pacific Power (SPPC), Tacoma Power (TPWR), and PacifiCorp East—Utah (PAUT). Due to transmission constraints during the COI outage, renewable resources in these areas are not used completely and are being spilled;
2. There is less spillage for Southern California Edison (CISC), Public Service of New Mexico (PNM), Turlock Irrigation District (TIDC), Pacific Gas and Electric Valley Area (CIPV), and

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Southern California Edison (CISC). Due to less inter regional imports, renewable resources in these areas are being utilized more and dispatched more; and

3. In the event of a COI outage, transmission constraints prevent full use of renewables. But California can import enough energy to avoid unserved energy.

Figure 12: Energy Spillage comparison for ADC PCM Case and COI Outage

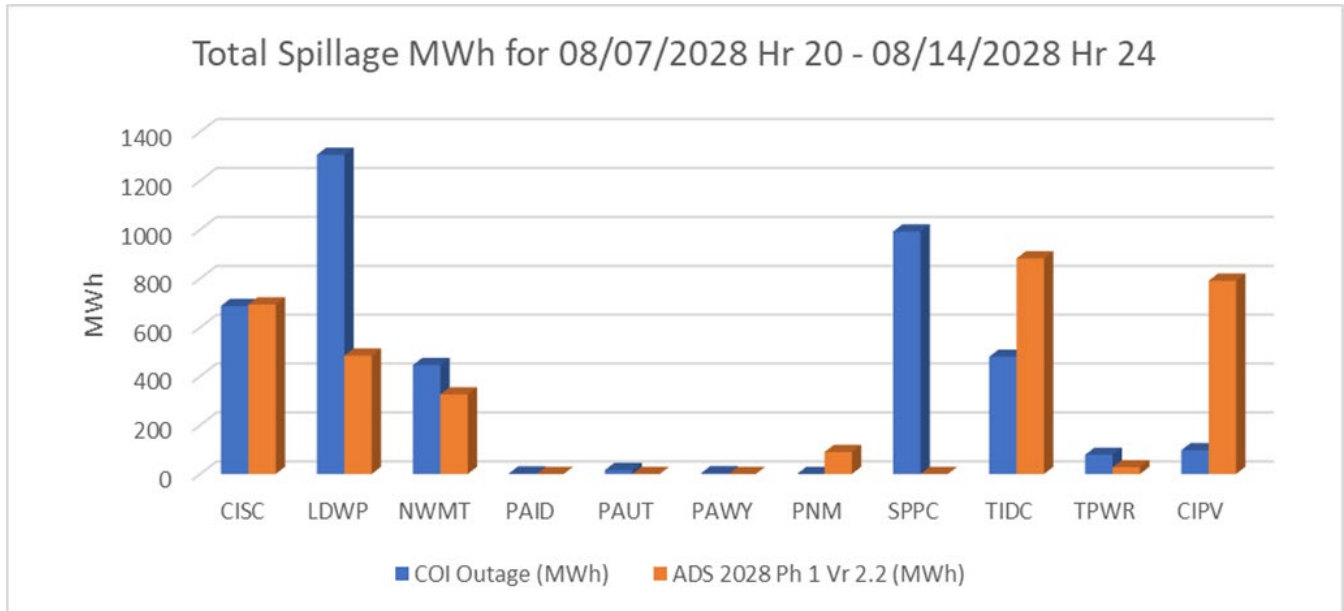
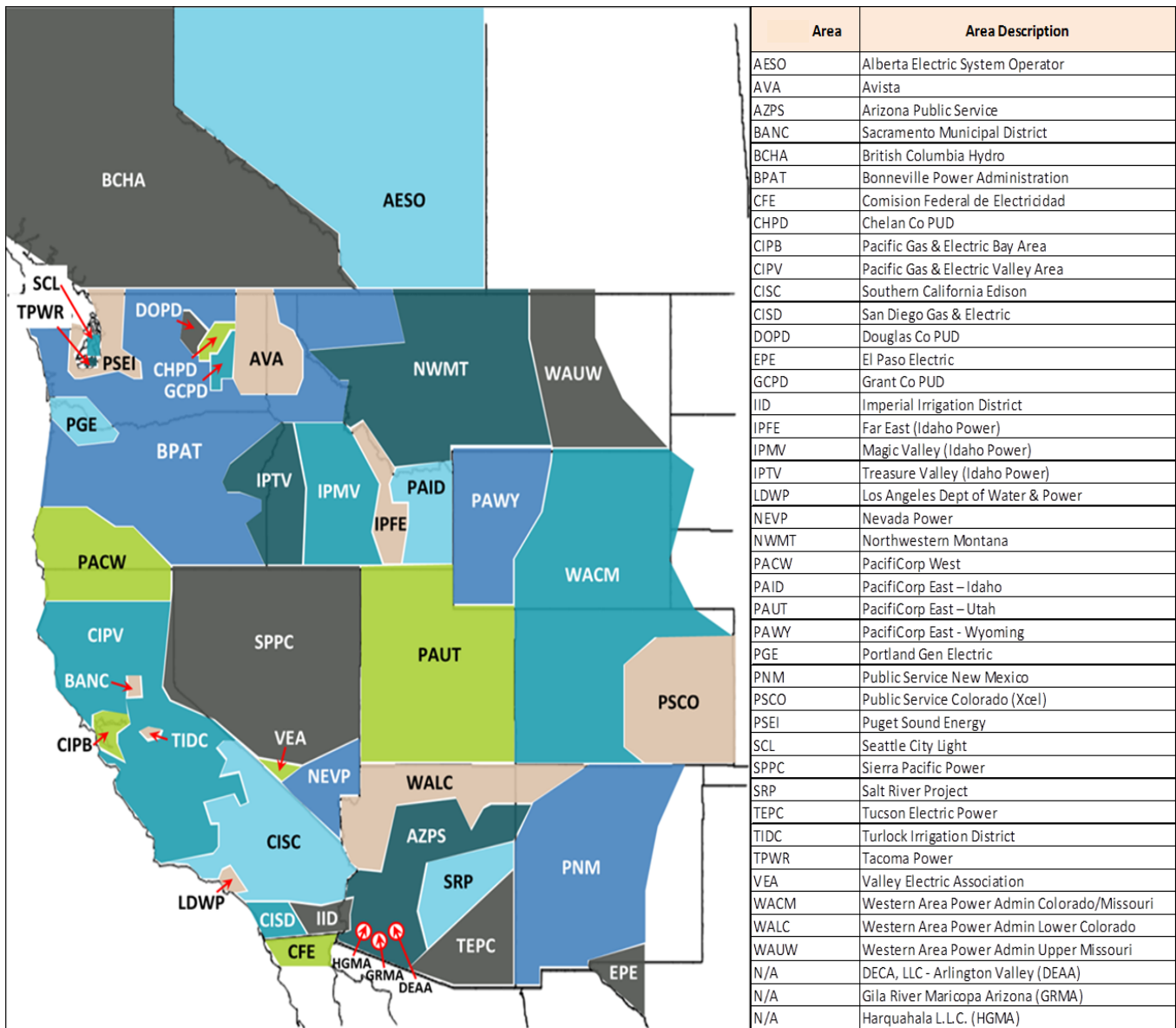


Figure 13: Load Areas Modeled in the Assessment



4.5. Transmission Path Utilization

The following metrics were used for this assessment to identify transmission Paths that are “highly utilized” for the duration of outage in the period 08/07/2028 Hr. 20 – 08/14/2028 Hr. 24:

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

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

Figure 14 and Figure 15 shows the most heavily utilized paths for the ADS PCM case and the COI outage respectively for the outage period. Figure 16 shows a map of WECC paths reference. Following are the key observations:

- For the COI outage, several major transmissions path are heavily utilized compared to the ADC PCM case due to higher inter regional transfers. The following paths are heavily used in the COI outage:
 - P75 Hemmingway Summer Lake,
 - P16 Idaho Sierra,
 - P83 Montana Alberta Tie Line,
 - P01 Alberta-British Columbia, and
 - P29 Intermountain-Gonder 230 kV.

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Figure 14: Most Heavily Utilized Paths—ADS PCM Case

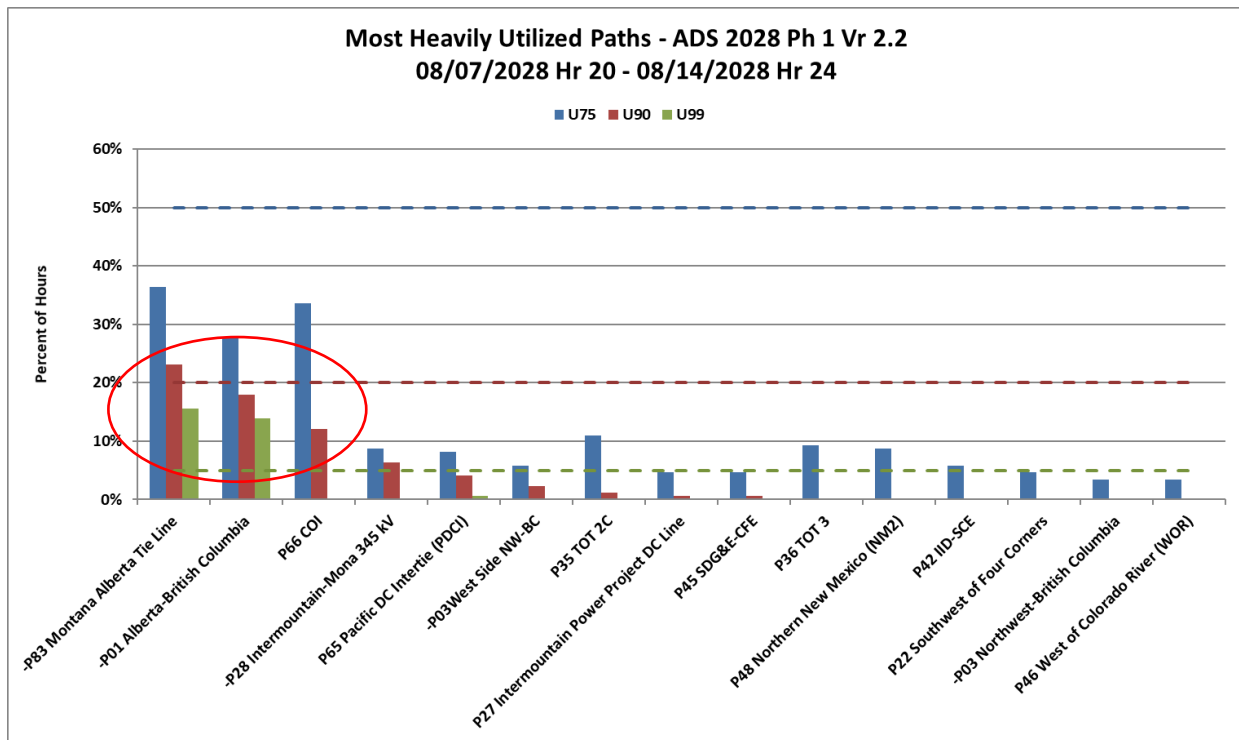


Figure 15: Most Heavily Utilized Paths—COI Outage

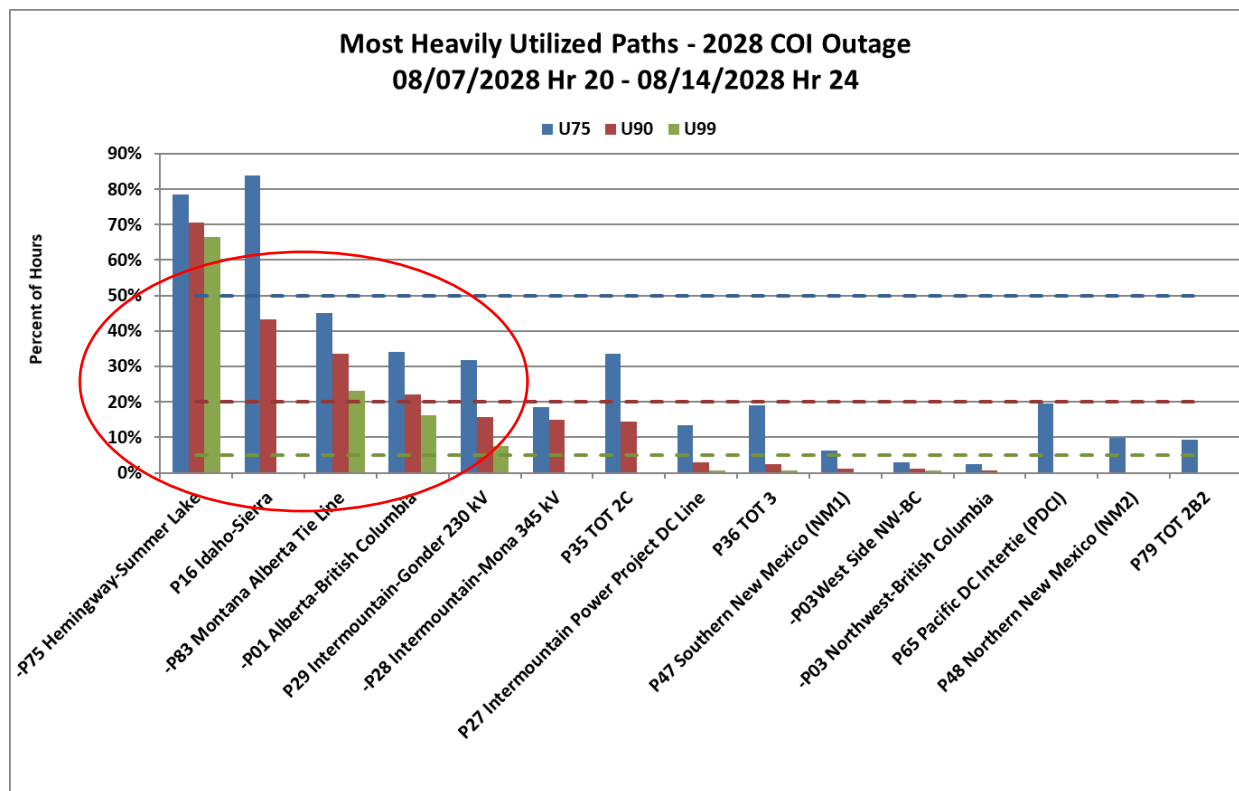
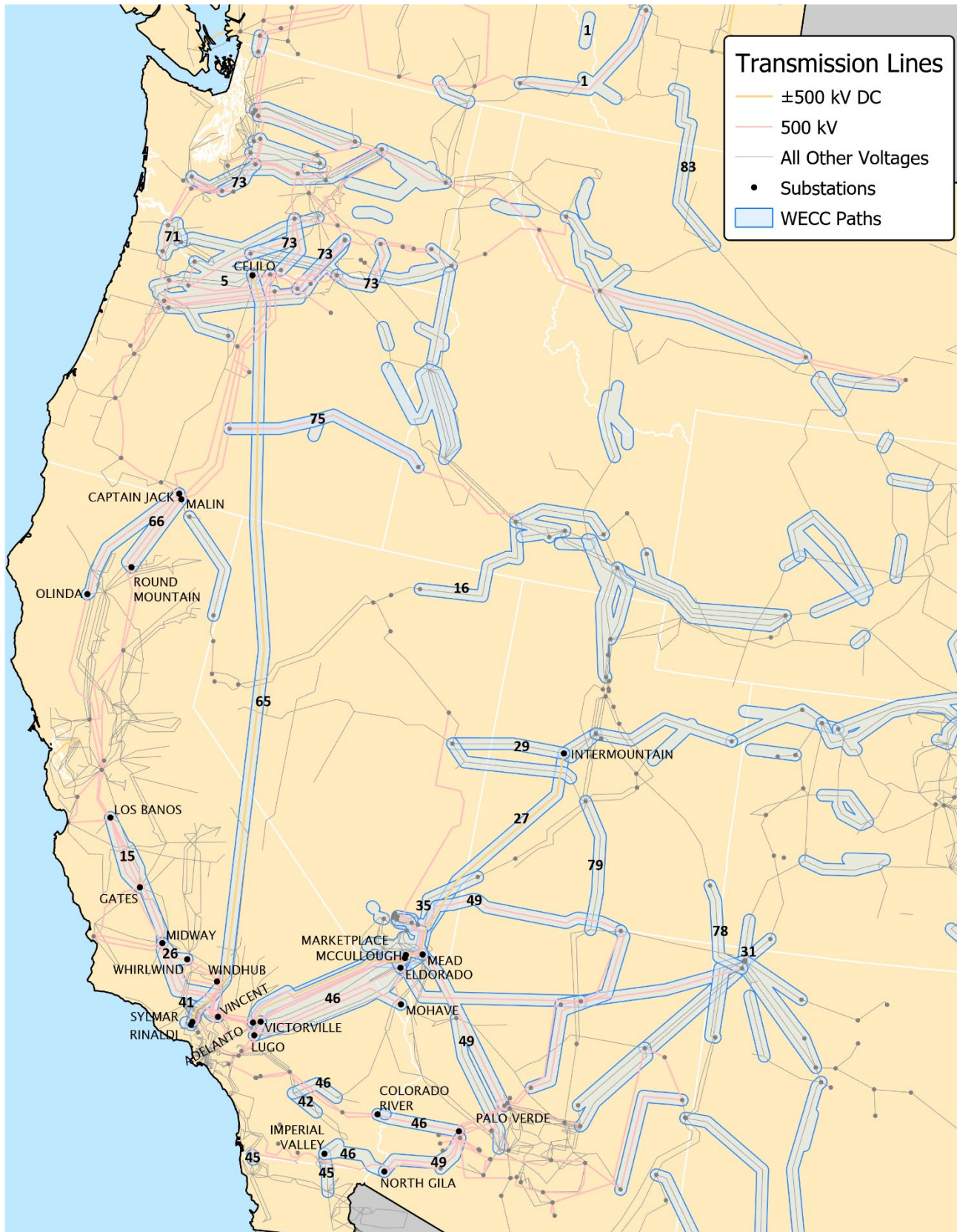


Figure 16: WECC Transmission Paths

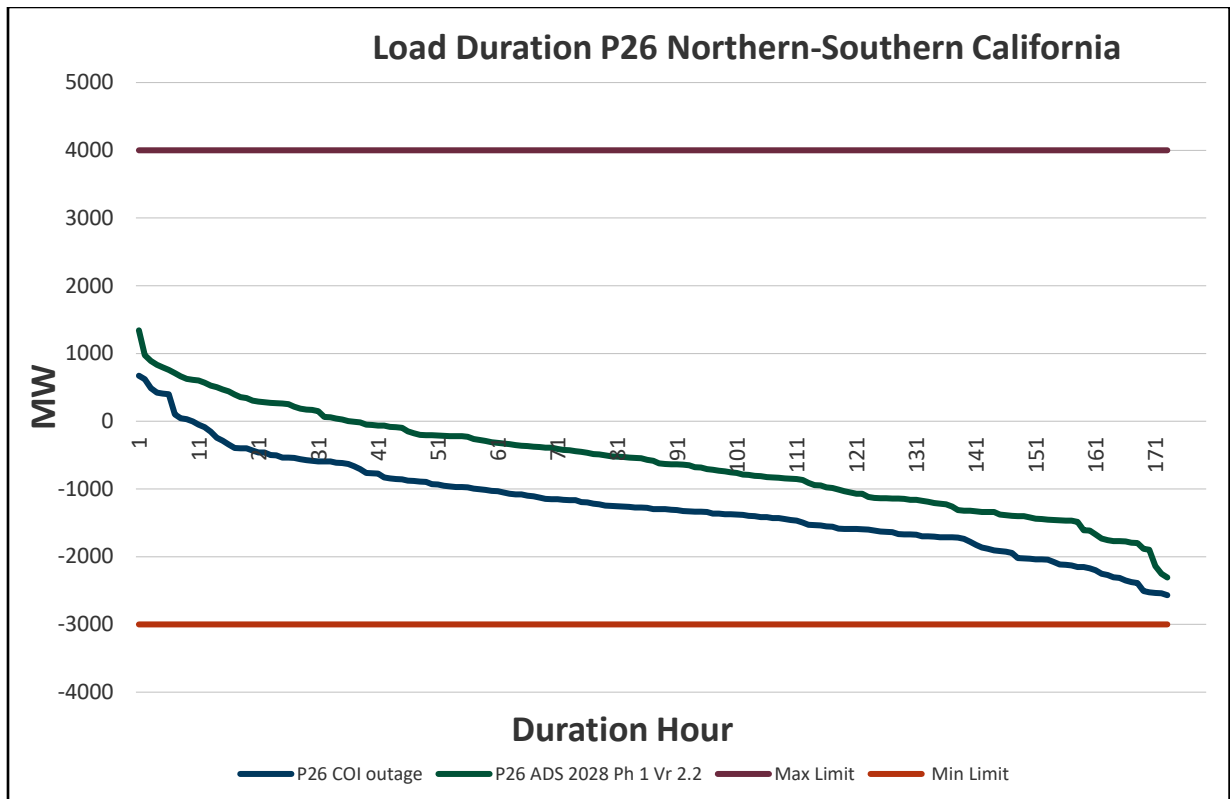


4.6. Transmission Path Load Duration

Figures 17 through 24 compare the load duration for the ADS PCM case and the COI outage for the outage period for select paths that were of interest due to how near they are to the outage conditions. The main observations were:

1. For Paths 26 Northern-Southern California and 31 TOT 2A the flows are reversed for much longer durations and their use is higher under the COI outage than under the ADS PCM case;
2. In the COI outage, Path 35 TOT 2C has higher use compared to the ADS PCM case, and the flows do not reverse during the outage period;
3. There is minimal change in use for Path 46 West of Colorado River (WOR) and Path 49 East of Colorado River (EOR) in COI outage;
4. In COI outage, Path 65 (PDCI) has much higher use during the outage period and flow reverses on the line for a few hours; and
5. In COI outage, Paths 78 TOT 2B1 and 79 TOT 2B2 have higher use during the outage period and flow reverses only for a much shorter period compared to the ADS PCM case.

Figure 17: Load Duration Curve—Path 26



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Figure 18: Load Duration Curve—Path 31

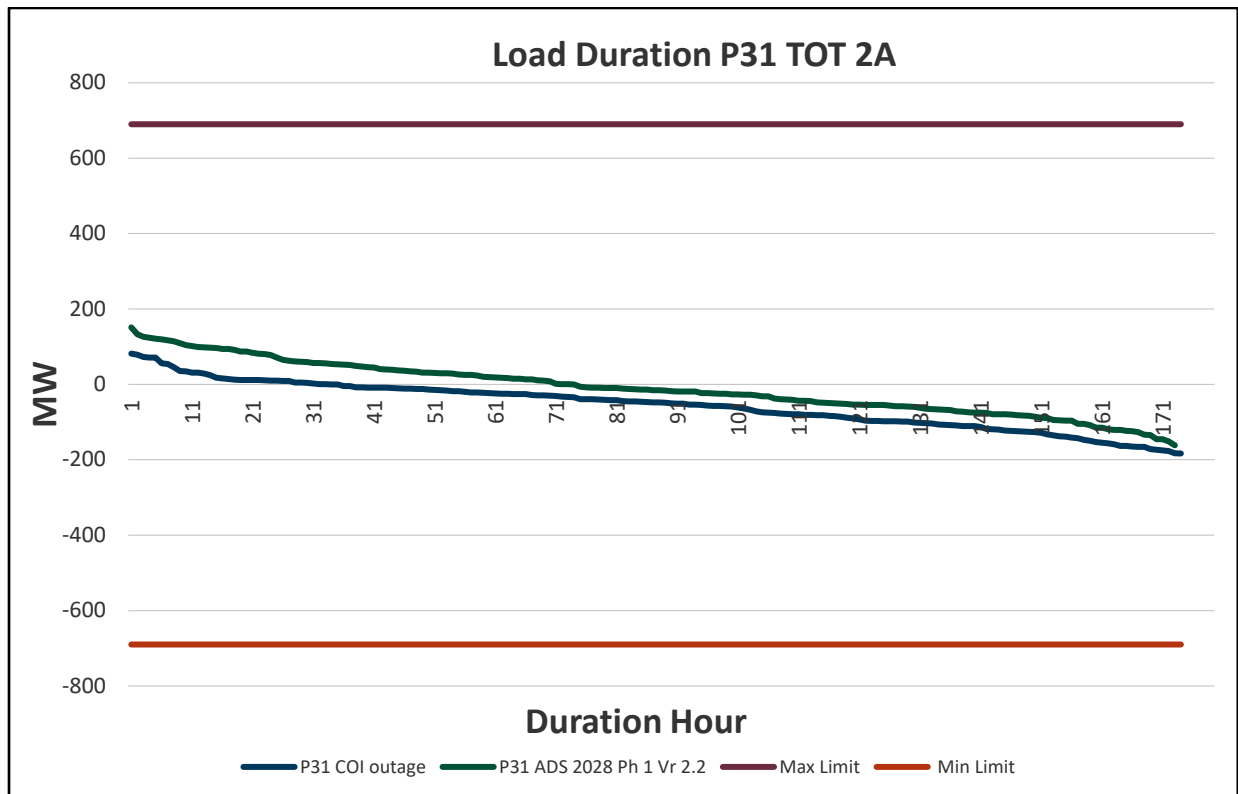
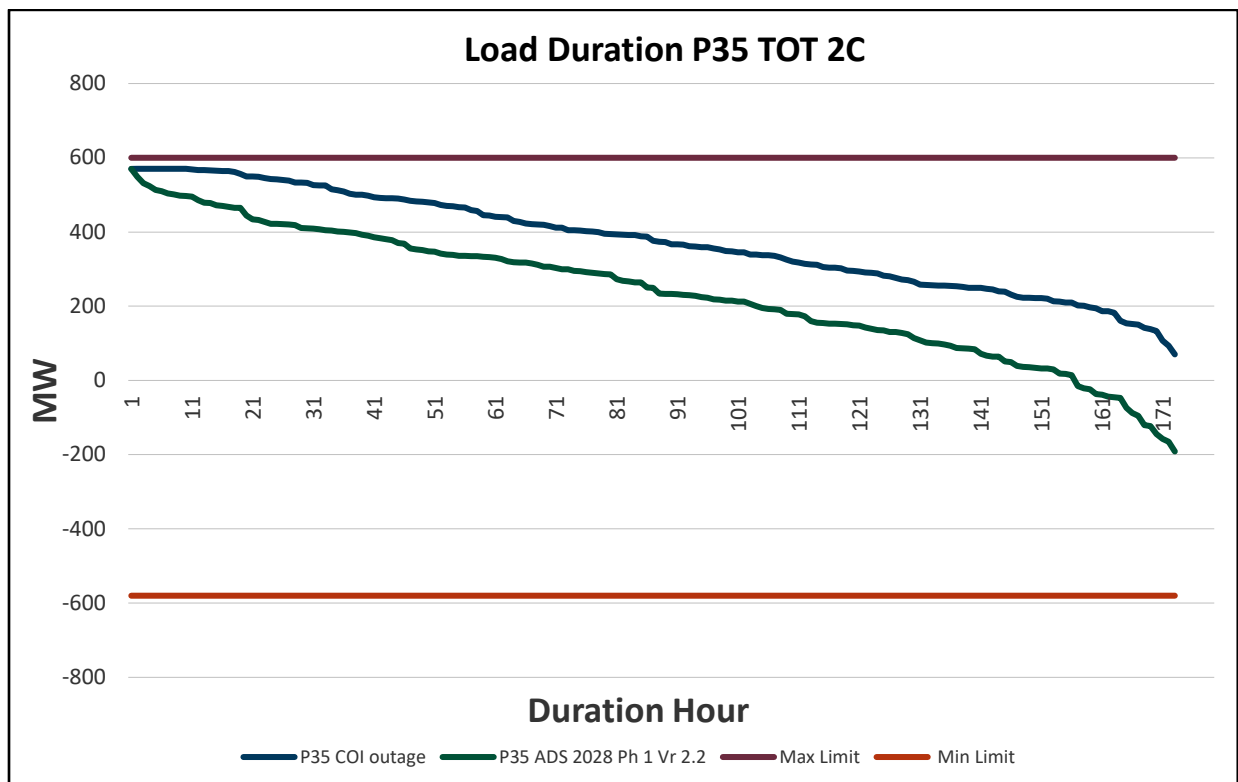


Figure 19: Load Duration Curve—Path 35



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Figure 20: Load Duration Curve—Path 46

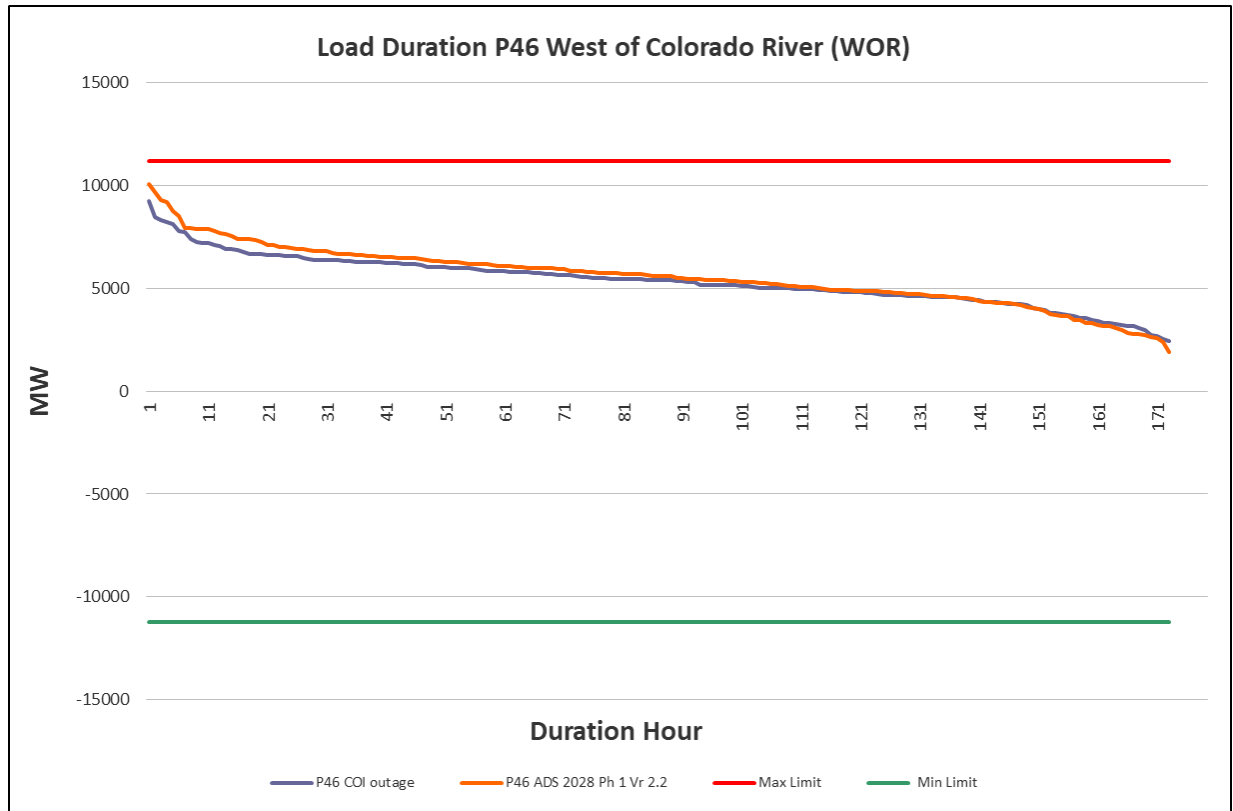
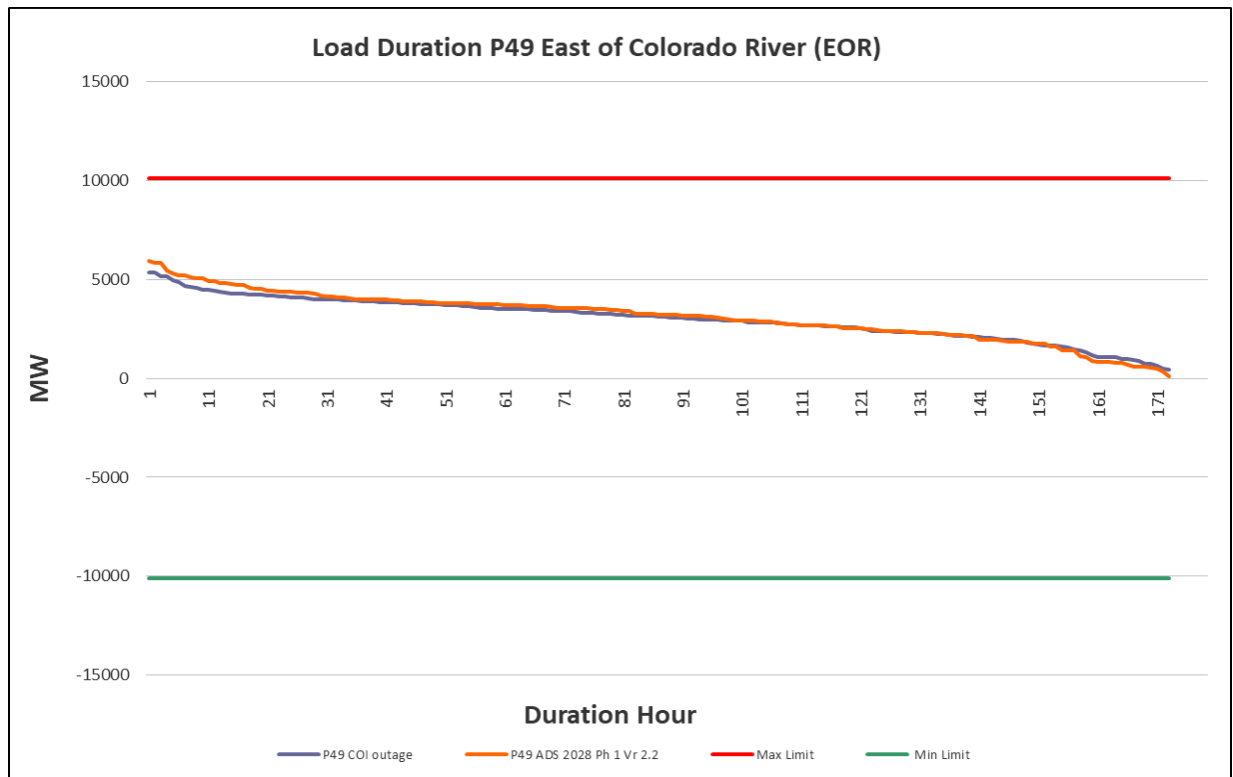


Figure 21: Load Duration Curve—Path 49



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Figure 22: Load Duration Curve—Path 65

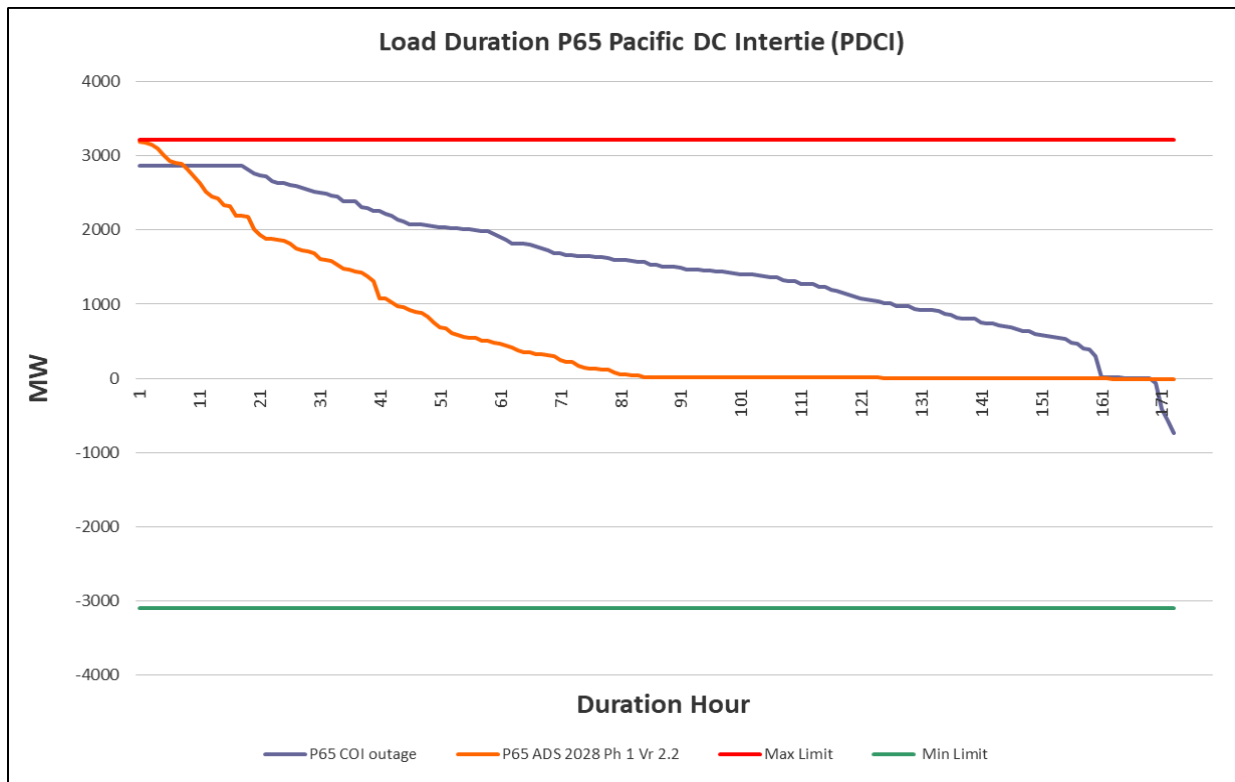


Figure 23: Load Duration Curve—Path 78

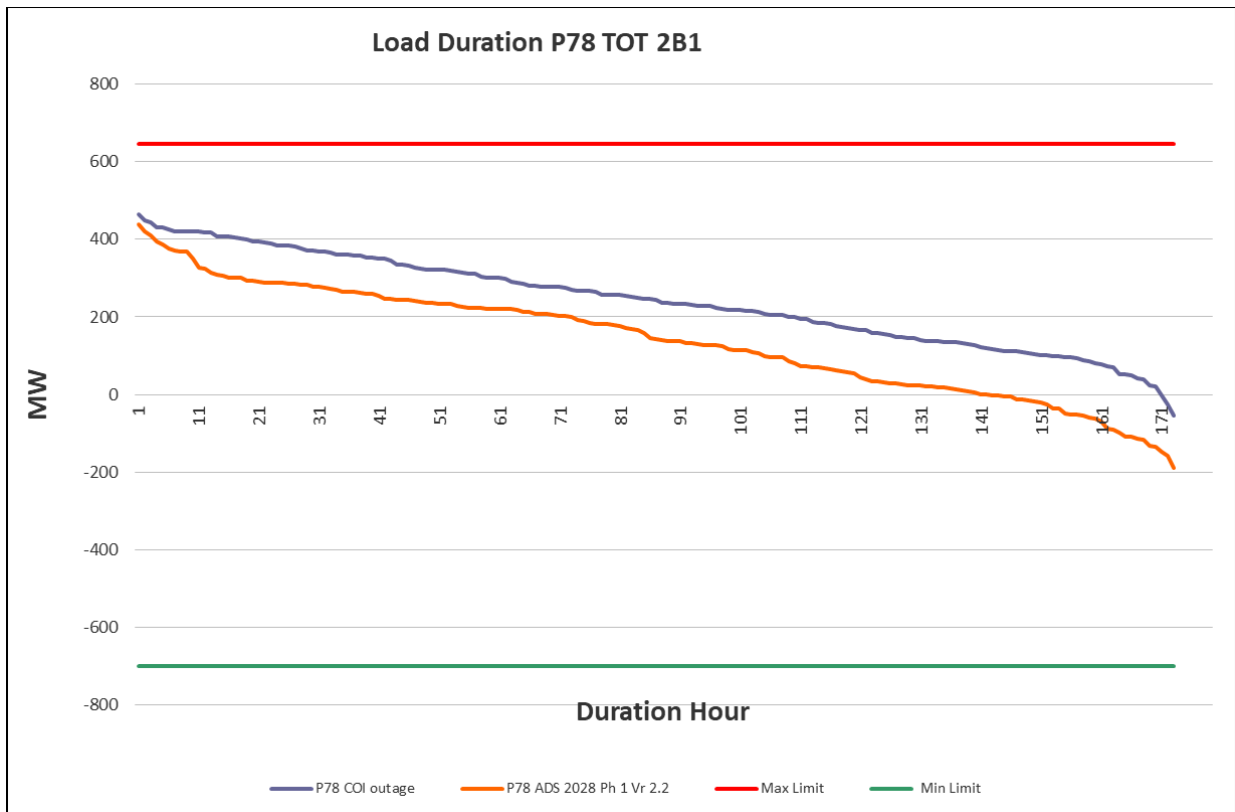
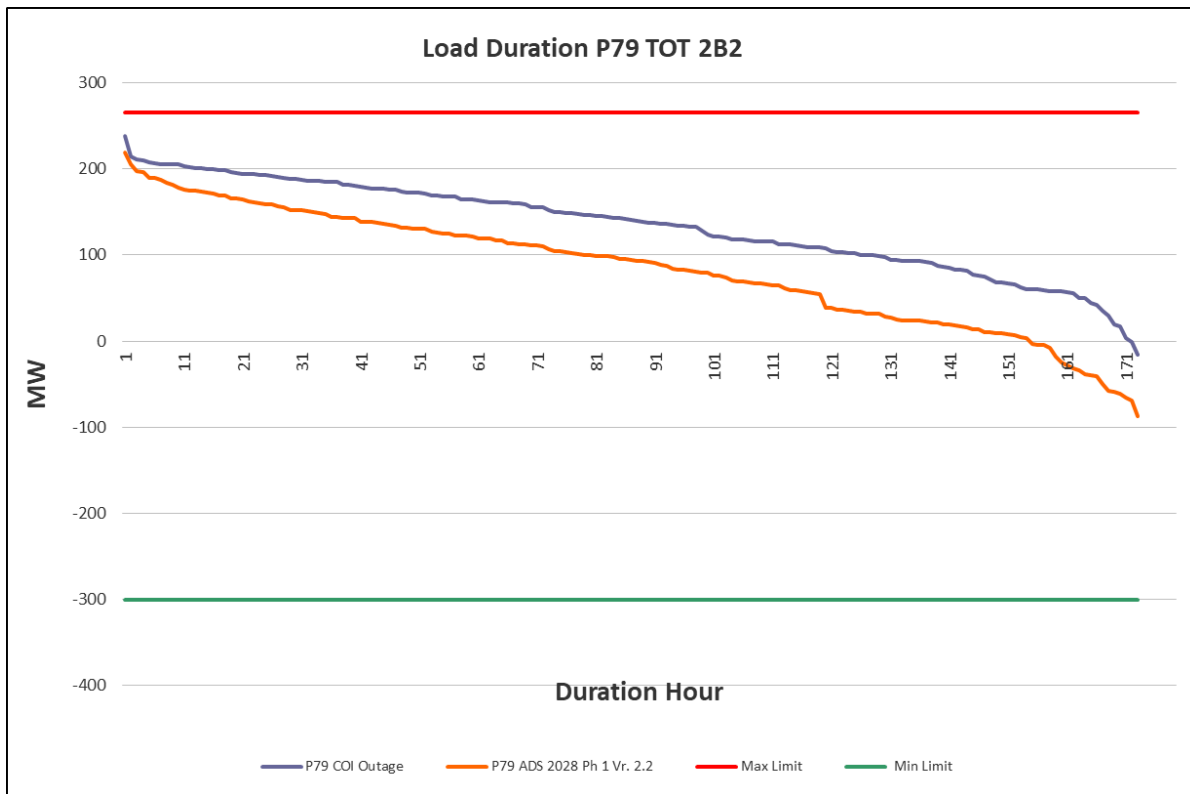


Figure 24: Load Duration Curve—Path 79



5. Power Flow and Transient Stability Analysis Results

Post transient power flow and transient stability analysis were performed for the two main outage events of the scenario. The results of which are described in the paragraphs below.

5.1. Outage Event 1

The first outage event with COI N-S flows at 4,800 MW included the simultaneous outage of the following lines:

1. Malin-Round Mt. 500 kV lines 1 and 2; and
2. Malin-Canby-Hilltop 230 kV line.

Several Remedial Action Schemes (RAS) were activated because of the outages, with the most significant including the following:

1. Tripping of 2,400 MW of Northwest Generation (wind and hydro);
2. Tripping of the Cascade-Delta 115-kV line (thermal relay); and
3. 1,400 MW braking resister inserted at Chief Joe 230-kV bus (approx. 30 cycles).

Post-Transient Results

The post-transient study did not result in thermal overloads reaching 125% or more, so a cascading test was not needed. The post-transient study did result in low voltages occurring on the 115-kV and 69-kV systems in southern Oregon and two thermal overloads on the 500-kV system. However, as the outage is an Extreme Event, no NERC or WECC system performance criteria were violated. A reactive margin study was not performed in this assessment.

The low voltages resulting from the first outage event are summarized in Table 5.

Table 5: Voltage Violations

Outage Event (Extreme)	Bus-Voltage (kV)	Voltage (kV)		
		Pre-Cont.	Post-Cont.	% Dev.
Malin-Round Mt. 500kV lines 1 & 2 Out	69	65.4	56.7	13%
Malin-Hilltop 230kV line Out	69	65.7	57	13%
	69	66.5	58	13%
	69	66.8	58.3	13%
	69	64.1	56	13%
	69	64.2	56.1	13%
	115	115.6	101.2	12%
	115	114.2	100.3	12%
	69	69.3	61.8	11%
	69	69.4	61.9	11%

The thermal violations resulting from the first outage event are summarized in Table 6.

Table 6: Thermal Violations

Outage Event (Extreme)	Impacted Facilities	% Loading
Malin-Round Mt. 500kV lines 1 & 2 Out	Northern California 500/230kV Transformer Bank	111%
Malin-Hilltop 230kV line Out	Northern California 500kV Line	107%

Transient Stability

The transient stability analysis for the first outage event did not result in any stability concerns. Though the outage is an Extreme Event, the system performance criteria used for less severe outages were applied in the analysis. Table 7 shows the system performance criteria used in the analysis.



Table 7: Transient Stability Analysis

Analysis	Criteria	Comments
Uncontrolled islanding	Unrestrained successive load loss or generation loss did not occur	None
Voltage recovery	Voltage recovery at all load-serving BES busses recovered to 80% of the pre-cont. voltage within 20 seconds	Criteria Met
	Following fault clearing and voltage recovery of 80%, voltages at applicable BES busses serving load did not dip below 70%, nor dip below 80% for more than 2 seconds	Criteria Met
Angular stability	All system oscillations following the event achieved positive dampening within 30 seconds	Dampened

5.2. Outage Event 2

Following the first outage event, the COI N-S flows were reduced to 600 MW and the case was normalized with all transformer taps, phase shifters, and static VAR devices allowed to adjust automatically. With the facilities tripped as part of the Event 1 study modeled out-of-service, the Captain Jack-Olinda 500-kV line outage was simulated as part of the Event 2 study.

The RAS activated by the contingency included the switching of shunt devices to maintain voltages but did not include any tripping of generation or pumps. As the COI N-S flows were reduced to 600 MW, the WECC-1 RAS was assumed to be inactive and was not simulated as part of the outage.

Post-Transient Results

The post-transient study did not result in any thermal violations or voltage violations following the Event 2 outage.

Transient Stability

The transient stability analysis for the second outage event did not result in any stability concerns. Though the outage is an Extreme Event, the system performance criteria used for less severe outages were applied in the analysis. Table 8 summarizes the system performance criteria used in the analysis. Figure 25 shows that, by five seconds, all the bus voltages have recovered to their pre-contingency levels. Olinda 500 kV has an interesting response at about two seconds; we were not able to determine the reason. Figure 26 shows the bus frequencies after the disturbance. There is a slight spike due to the generation drop RAS activating, but, after the five second mark, everything stabilizes pre-contingency. Figure 27 shows the generator angles and shows that none of the generators in that area are unstable and spinning out to infinity.

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Table 8: System Performance Criteria

Analysis	Criteria	Comments
Uncontrolled islanding	Unrestrained successive load loss or generation loss did not occur	None
Voltage recovery	Voltage recovery at all load-serving BES busses recovered to 80% of the pre-cont. voltage within 20 seconds	Criteria met
	Following fault clearing and voltage recovery of 80%, voltages at applicable BES busses serving load did not dip below 70%, nor dip below 80% for more than 2 seconds	Criteria met
Angular stability	All system oscillations following the event achieved positive dampening within 30 seconds	Dampened

Figure 25: Bus Voltage

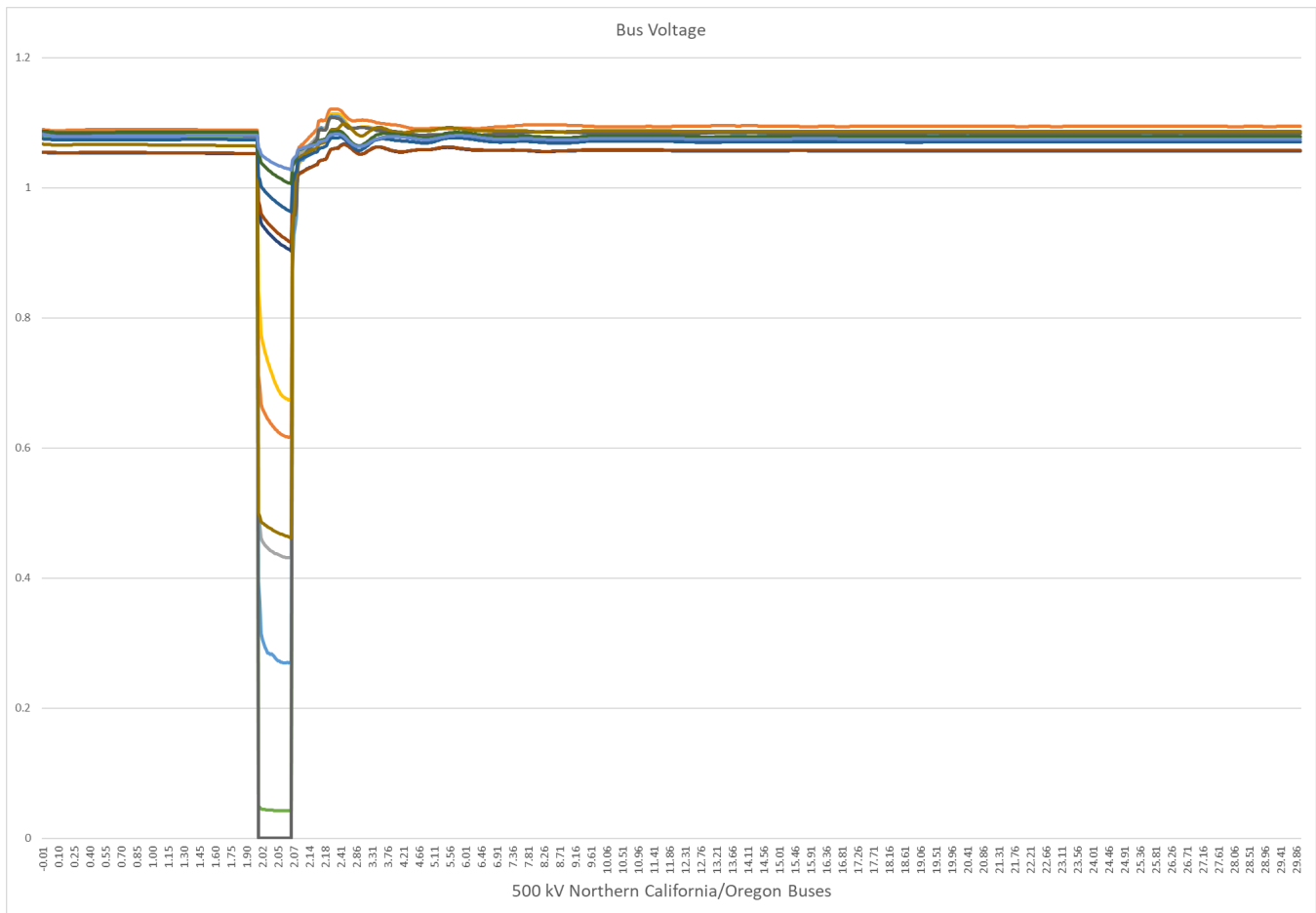


Figure 26: Bus Frequency

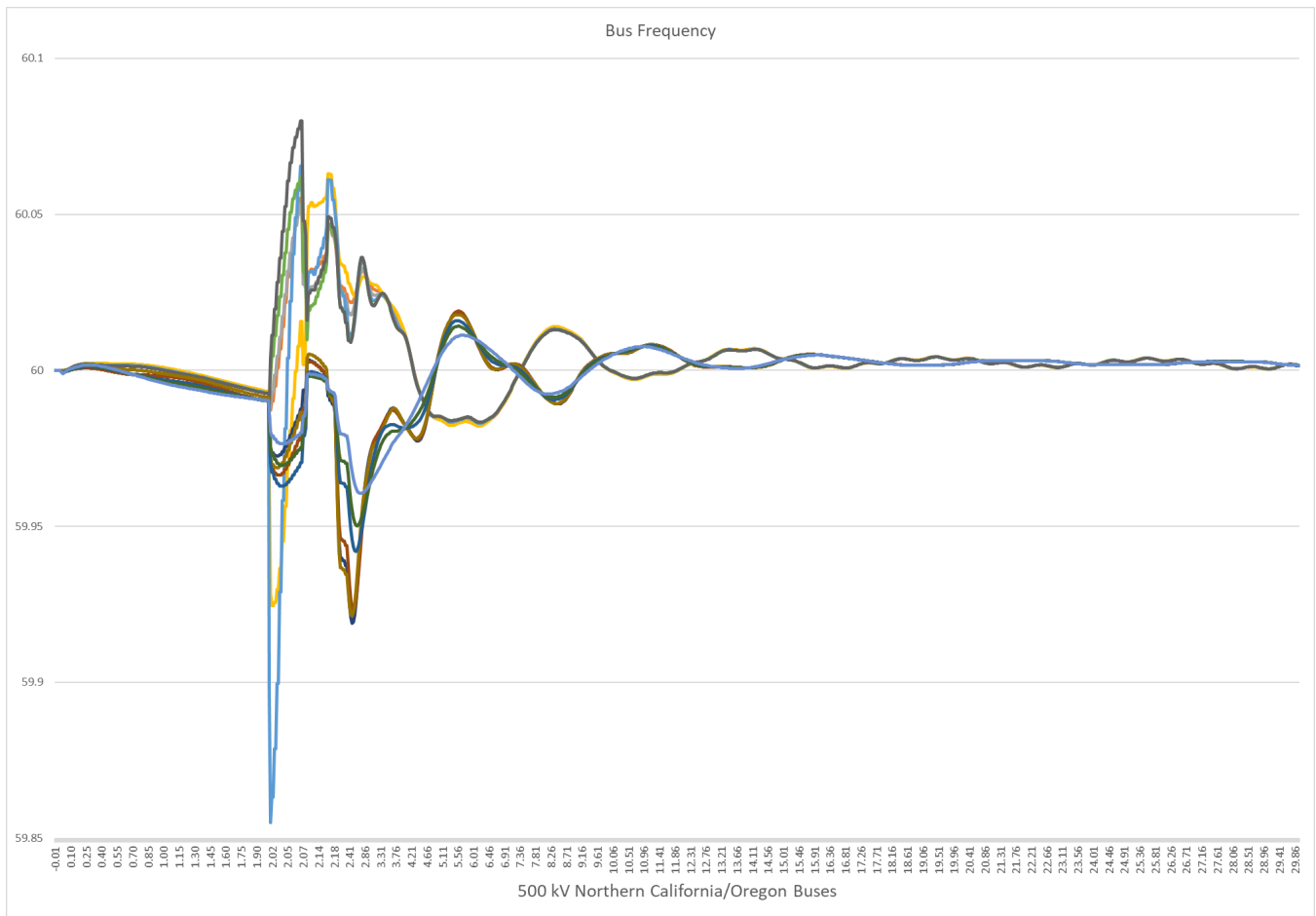
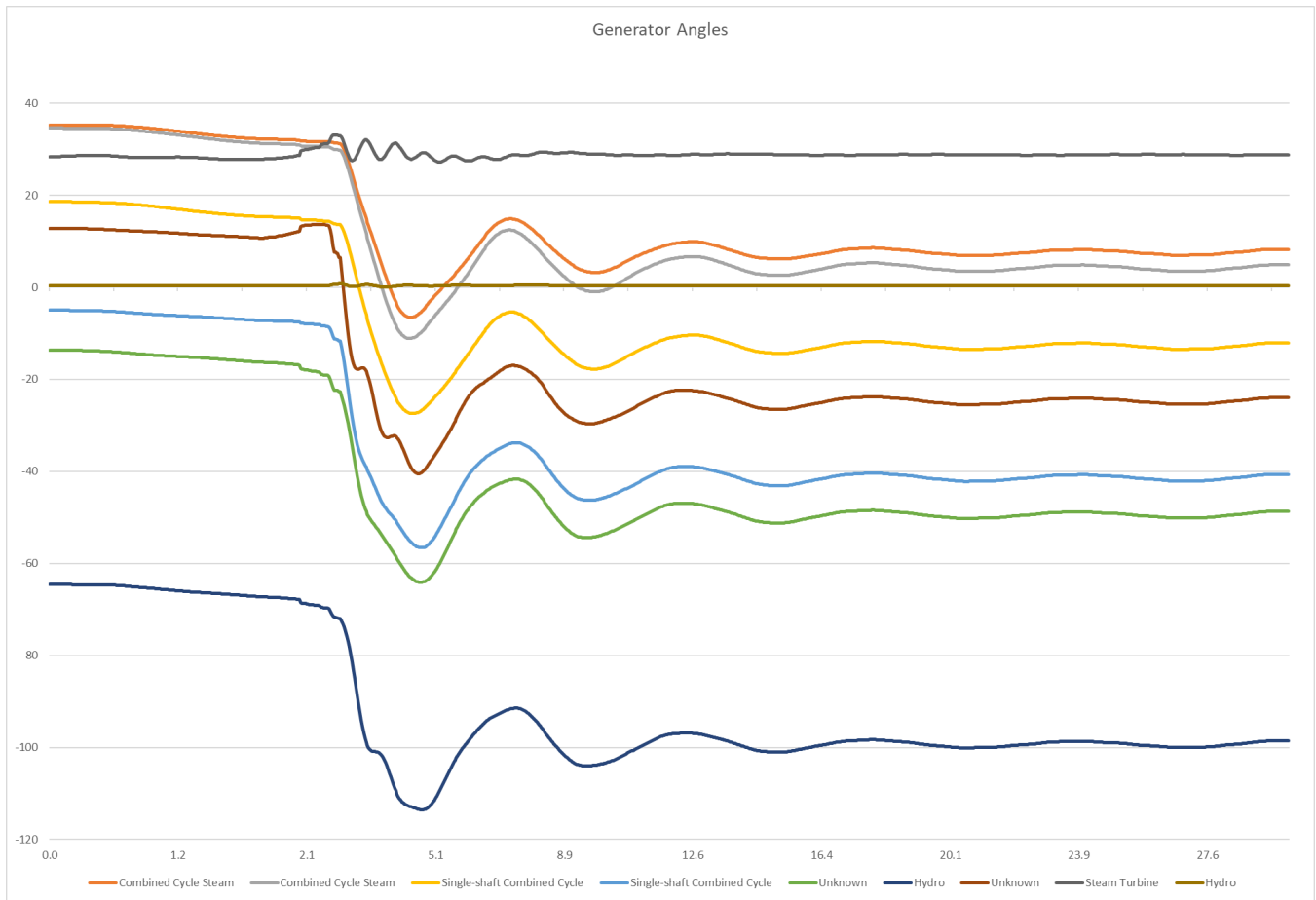


Figure 27: Generator Angles



6. Observations and Conclusions

6.1. Resource Adequacy Results:

The WI was found to be resilient to an Extreme Event during the COI outage. The various analysis during COI outage for the duration of the outage period leads to the following observations, which may be of interest for new resource development, meeting renewable portfolio standards (RPS), and upgrading or developing new transmission lines in the WI:

1. There are adequate resources and no unserved energy in the WI to maintain reliability during an event in which wild fires disrupt Path 66 COI.
2. There was higher use of some of the major paths during the outage period due to higher inter-regional transfers using these paths. The outage was for seven days, and some of the transmission lines may not be designed for such use, but, high path use did not limit the ability of the BES to deliver power to serve load.
3. During a COI outage, there is a 25 percent reduction in imports to the California region. This is compensated by higher production of certain resource types; mainly, combined cycle and combustion turbine.
4. During COI outage, the current transmission system is not able to fully use and transfer renewable resources through inter-regional transfers.

6.2. Power Flow Observations

The key takeaways from both scenarios in power flow for stability and transient analysis are:

1. No cascading outages were seen. Overloads and voltage violations were seen but were not considered to be of a concern because of the extreme nature of the event.
2. Under Event 2, the most important question was whether the system remained stable. The system is designed to withstand a Malin-Round Mt. double line outage at the studied flows, but the Malin-Hilltop 230-kV line was also taken out, which disables Path 76 into Nevada. As was seen in the report above, the WI remained stable under this scenario.

7. Recommendations

This study is the first of its kind to evaluate the WI during an extreme natural disaster. It would be valuable to study more outages caused by extreme natural disasters to test stability and adequacy of under other contingencies affecting different parts of the Western Interconnection. Doing so would add to the knowledge of the BES's resiliency and could identify potential reliability risks.

One of the challenges of this study was collecting appropriate and up-to-date data to model the assumptions for the scenario. Participants in future studies should seek partnership with other entities working on similar studies to help create more scenarios and assumptions. Also, future assessments should explore potential partnerships with national laboratories, taking advantage of the labs' technical expertise and modeling capabilities. The 2028 ADS planning cases used for this assessment were based on two-year-old data and assumptions. The task force also recommends aligning this study more appropriately with the ADS planning case building cycle to use the most current data and assumptions.

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