Variability in Loads and Resources Assessment

Variability in Loads and Resources Advisory Group

2021

Executive Summary

The resource mix is changing from fossil generation to renewable generation, which has high variability based on weather conditions. Extreme weather events have been observed in the last several years in western North America. A combination of extreme weather events, lack of firm resources, and the variability of the generation (dependent on weather) could cause unserved energy in the system. This has been observed in the last several years (i.e., February 2021 extreme cold wave event in Texas and the August 2020 extreme heat wave event in southwestern United Sates). Such unplanned or unforeseen events increase the load on the electrical grid, resulting in unserved energy, which is a reliability risk to the Western Interconnection. This study intends to investigate the impact of an interconnection-wide extreme heat wave event and determine whether battery energy storage systems (BESS) could mitigate reliability risks in the interconnection.

To model the extreme weather event, an hourly load forecast was developed for a two-week period—August 22 through September 5—using assumptions from the California Energy Commission 1-in-10 and 1-in-20 load forecasts and applied to the 2030 Anchor Data Set (ADS) production cost model (PCM). This was the period in which the peak load occurred in the 2030 ADS PCM. Two simulations were performed, one representing an increased load of 7% (1-in-10) and one of 9% (1-in-20). After increasing the load, the simulation resulted in unserved energy for several hours, specifically on August 29 and September 5. To mitigate the impact of increased load, several BESS units were added near the load centers in each Balancing Authority Area (BAA). The capacity of the battery is equal to the level of the peak unserved energy in each region. A total of about 11,000 MW of BESS were added to the interconnection. The addition of the BESS in various BAAs was able to mitigate the unserved energy during the two-week simulation period in the PCM.

For power flow modeling, one hour—August 29 at 8 p.m. MT—was exported from the PCM for evaluation of frequency response from the BESS. The 2030 Heavy Summer power flow was first modified to match the generation and load from the exported hour. Dynamic models, consisting of the latest generic models approved for renewable facilities, were developed for the additional BESS included in the power flow model. Two simulations were conducted to evaluate the frequency response performance of BESS when two Palo Verde nuclear units were tripped offline. In the reference simulation, parameters in the BESS dynamic models were set so that they were not allowed to provide frequency response, whereas, in the second simulation, these parameters in the BESS dynamic models were set so the BESS facilities could provide frequency response. When the BESS was able to provide frequency response, the frequency deviation resulting from tripping two Palo Verde units was reduced and recovered to a frequency closer to 60 Hz.

The results from the study indicate the BESS, which is positioned near the load centers, mitigated all unserved energy in the system during the two-week period of the simulated heat wave. The simulated study results indicate that BESS can provide valuable ancillary services to complement load-serving

capability. The frequency response of the system improved with the addition of BESS and can be evaluated for other benefits such as ramping capability. Recommendations from the study are:

- WECC recommends that entities study the variability in electric load and generation, evaluate the reliability risks, and assess the potential uses of BESS.
- Suggestions for future assessment work:
    - Perform a full year PCM run with the additional BESS modeled in the study case to see the impact during the time without the heat wave.
    - Simulate a cold weather event on a regional or system level.
    - Perform further simulations to investigate a detailed impact on the ancillary services with the BESS.
    - Study the impact of regional heat waves with hybrid BESS systems modeled (i.e., BESS co-located with renewable resources).
- The Anchor Power Flow Work Group (APFWG), Production Cost Data Subcommittee (PCDS), and Reliability Assessment Committee (RAC) should establish the same generation resource definitions for PCM and power flow to perform more consistent power flow, stability, and dynamic simulations.

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Introduction and Purpose

The Western Interconnection was struck by a heat wave from August 14 through August 19, 2020, which resulted in strained generation and transmission capacity. The California Independent System Operator (CAISO) had to declare energy emergencies and shed firm load to maintain operating reserves needed for reliability of the Bulk Power System (BPS) [1]. Several Balancing Authorities (BA) were one contingency away from also shedding load. WECC analyzed this event using the structure of the Electric Reliability Organization's (ERO) Event Analysis Process [2]. The findings and recommendations from this event analysis indicated that the summer peak demand has increased, creating competition for generation and transmission capacities in the interconnection. Due to the changing resource mix from fossil fuels to renewable generation, the evening generation ramping requirements are anticipated to become even more challenging to reliability. The report stated that, without large-scale storage capabilities, entities will need to depend on fossil fuel generation or real-time markets to meet the evening demand.

Considering the above-mentioned events, the purpose of this study is to determine whether the impact of variability in loads and resources in the interconnection could lead to risks to the reliability of the Bulk Power System (BPS). This study modeled the variability in loads and resources in a production cost model (PCM), followed by a dynamic analysis, to identify potential BPS reliability risks related to variability in loads and the changing generation portfolio. The study addressed the following Reliability Risk Priorities [3]:

- **Extreme Natural Events**: Impact of an interconnection-wide heat wave event; and
- **Changing Resource Mix**: Response of battery energy storage systems (BESS) to help mitigate risks associated with variability in loads and resources.

This study was developed to assess the interplay of a changing resource mix with more variable resources, increasing frequency of extreme heat waves across the interconnection, and the increased use of BESS to mitigate reliability risks to the BPS. This assessment explored whether additional BESS could provide sufficient flexibility to ensure load can be served during heat wave events. The assessment proceeded with four main steps:

1. Identification of load shapes that reflect the heat wave in the interconnection;
2. Evaluation of potential unserved energy impacts and congestion in the system;
3. Mitigation of reliability issues arising from increased penetration of inverter-based resources by adding BESS in locations with unserved energy; and
4. Comparison and analysis of the performance of BESS in mitigating impacts of unserved energy and congestion.

Modeling and Key Assumptions

Process Flow

The Variability in Loads and Resources (VLAR) assessment began with creating the PCM. The process flow below provides the steps for evaluating the impact of increased loads and BESS to mitigate unserved energy in the Western Interconnection.

1. The study process began with the 2030 Anchor Data Set (ADS) PCM case.
2. Load assumptions from the California Energy Commission (CEC) 2020 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast Update (CEDU) 2020-2030 were used to provide 1-in-10 and 1-in-20 heat wave load projections for the 2030 time frame. The terminology of 1-in-10 and 1-in-20 heat wave loads refer to the probability that a heat wave event occurs once in 10 years and the more severe case of a heat wave that occurs once in 20 years. For areas in California, the CEC provided multipliers to convert the peak loads from a 1-in-2 heat wave load projection to 1-in-10 and 1-in-20 heat wave loads. For areas outside of California, WECC staff developed weighted average multipliers to adjust the loads modeled in the ADS PCM case. The peak loads modeled in the original ADS PCM cases were average loads (i.e., 1-in-2 heat wave loads).
3. The PCM was modeled initially for a heat wave assuming 1-in-10 heat wave loads, and the unserved energy was recorded. A second more severe heat wave was modeled using the 1-in-20-year heat wave loads, and an increase in unserved energy was recorded.
4. To address the problem of unserved energy, four-hour BESS were added to areas with unserved energy. When the four-hour duration was not enough to mitigate unserved energy, the battery duration was increased to six hours for 1-in-10 loads and eight hours for 1-in-20 loads. The BESS resources were adjusted with total capacity and energy to mitigate an area's peak unserved energy and were split into several smaller units that were spread out on high voltage buses at or near various load substations in the area.
5. Loads and resources at peak load hour with a high amount of BESS dispatch were exported to model in a dynamic platform for further transient stability analyses.

Figure 1: Process flow chart shows the modeling steps and assumptions.

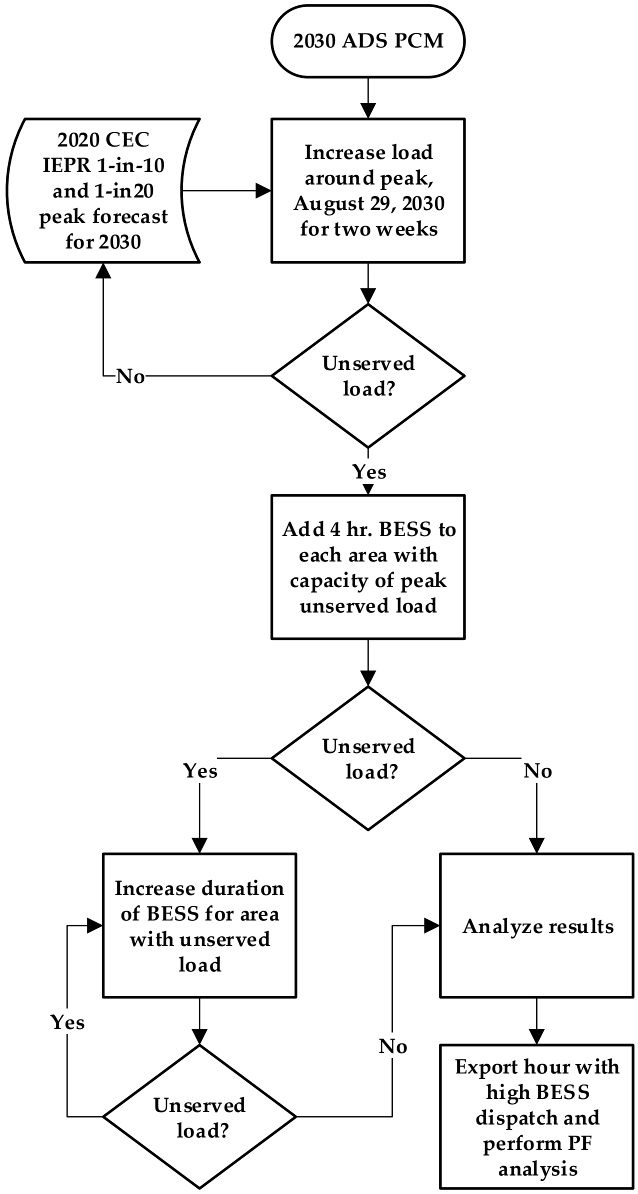

Figure 1: Process flow chart

Input Data

2030 ADS PCM

The 2030 ADS PCM V2.3 was the starting point of the study. This dataset is created on a two-year cycle and is used by WECC and entities throughout the interconnection as the starting point for PCM studies and analysis of the BPS.

CEC Load Data

The CEC creates the Integrated Energy Policy Report (IEPR). The 2020 IEPR provides a consistent approach to identify and solve the state's pressing energy needs and issues. The report, which is crafted in collaboration with a range of stakeholders, helps develop and implement energy plans and policies for California [4]. The CEDU Update 2020-2030 is part of the 2020 IEPR.

The CEDU 2020-2030 Baseline Forecast—High Demand case [5] was used to model loads in PCM. This forecast includes a single net peak value for each area in California for 1-in-2, 1-in-5, 1-in-10, and 1-in-20 projected demand through 2031. The increase in peak from 1-in-2 to 1-in-10 and 1-in-20 in this dataset was used to increase the load over a two-week period around the system peak in the 2030 ADS PCM, occurring on August 29, 2021. The load increase was applied to every hour during this period. Table 1 shows the percentage of increase for each California load area. The area abbreviations are explained in Table 9 in the Appendix. The weighted average of the California load areas was derived and used as a proxy for the percentage increase across the rest of the interconnection. The 1-in-10 and 1-in-20 weighted average increase for areas outside of California was 7.08% and 8.99%, respectively. This was considered a reasonable assumption for a heat wave event across the interconnection, as the CEDU forecast's weighted average includes areas of diverse climates.

Table 1: CEC load data

	2030 Peak Values from CEC IEPR (MW)			2030 Load Increase	
Area[1]	1-in-2	1-in-10	1-in-20	1-in-10	1-in-20
CIPB	9,698	10,322	10,487	6.44%	8.13%
CIPV	14,120	15,014	15,249	6.33%	7.99%
CISC	26,676	28,369	28,839	6.35%	8.11%
CISD	4,871	5,310	5,358	9.00%	10.00%
LDWP	7,045	7,731	7,909	9.74%	12.26%
IID	1,202	1,258	1,264	4.63%	5.09%
TIDC	708	772	800	8.97%	12.92%
BANC	4,936	5,379	5,574	8.97%	12.92%
VEA	176	192	194	9.00%	10.00%

[1] Table 9 in the Appendix defines each area.

PCM Modeling and Assumptions

The ADS 2030 PCM dataset was modified to stress the interconnection by reflecting the heatwave conditions across the West and worst-case scenario where load shed would be required by several BAs. This included potential retirements and increasing load across the interconnection as described below.

Additional Retirements

To model the worst-case scenario, coal retirements in addition to those already in the 2030 ADS PCM were assumed. These retirement assumptions came from PacifiCorp's 2019 Integrated Resource Plan (IRP) [6].[2] and the United States Energy Information Administration (U.S. EIA) Form EIA-860 [7]. The nine coal generating units in Table 2 were assumed to be retired in this study case, which adds up to a total capacity of 3,065 MW. The rest of the coal generation is modeled consistent with the 2030 ADS PCM.

Table 2: Accelerated coal retirements

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
Ray D Nixon 1	12/31/2029	208	EIA-860 2020

Load Modelling Assumptions

The CEC 2020 IEPRs 1-in-10 and 1-in-20 peak load forecasts for 2030 were used as the sources for peak load assumptions. The loads for each area were increased by the percentage indicated in Table 1 for a two-week period from August 22 to September 5, 2030. During this time, the system peak load occurred in the 2030 ADS PCM. Figure 2 shows the peak load in MW for each region for the 2030 ADS PCM and the value to which the peak load was increased in the scenarios simulating 1-

[2] In the recently published 2021 PacifiCorp IRP, projected retirements are updated.

in-10 and 1-in-20 heat wave loads. The new loads were used to simulate a heat wave condition and were included in the PCM run.

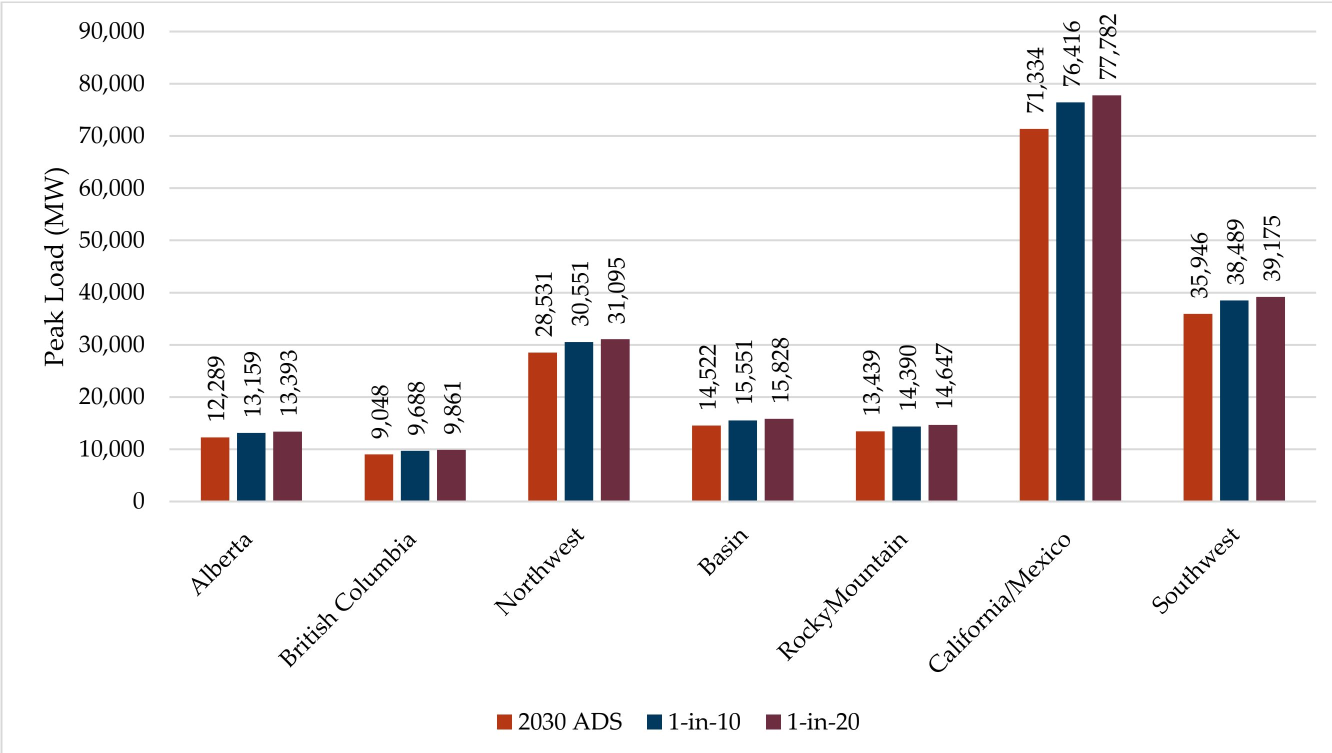

Figure 2: Peak load by region–1-in-10 and 1-in-20

A map showing the approximate boundaries of these regions is show in Figure 3. The BAs that make up each region are defined in Table 8 in the Appendix.

Figure 3: Approximate regional boundaries

Unserved Energy

When higher loads were modeled, unserved energy was observed in many areas throughout the interconnection. Figure 4 shows the regions with unserved energy in megawatt hours. For details on unserved energy by area, refer to Table 5 in the Appendix. System total unserved energy after retiring coal units and increasing load for the 1-in-10 and 1-in-20 cases, respectively, was 33,735 MWh and 60,567 MWh for the two-week period. Most unserved energy occurred on August 29 and September 4 during the evening ramp as seen in Assessment and Results, Figure 7.

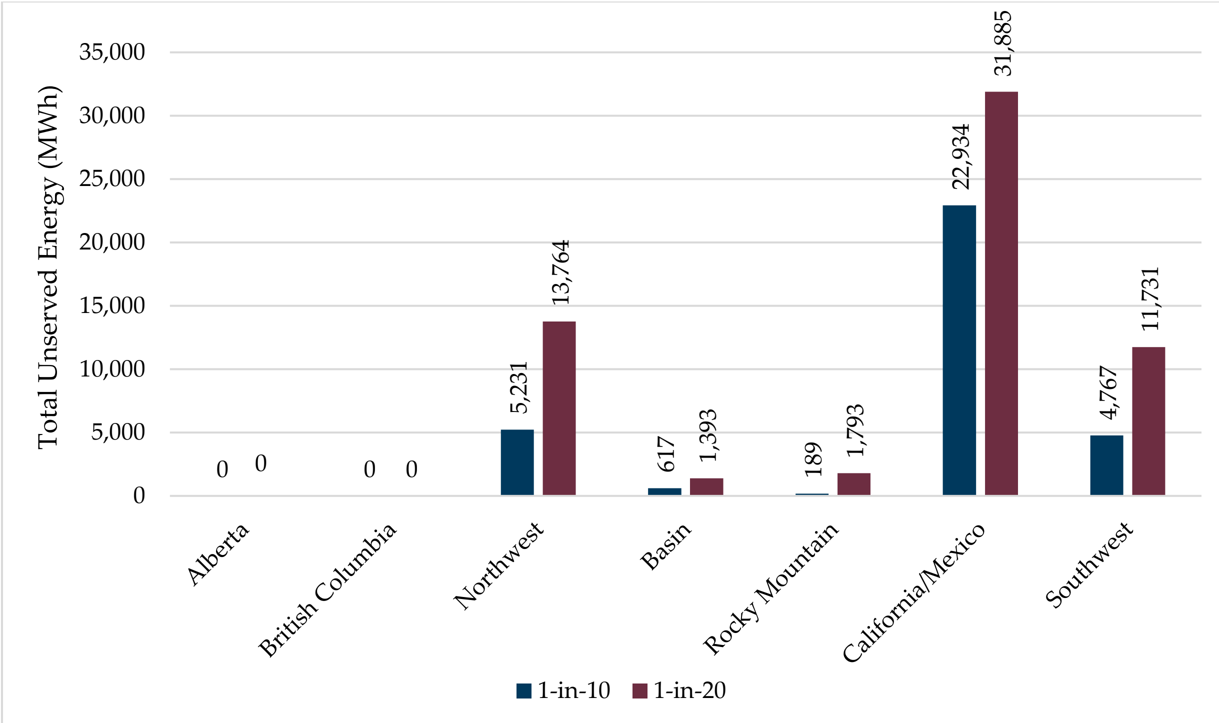

Figure 4: Total unserved energy by region

Peak Unserved Energy and Battery Sizing

The instantaneous peak unserved energy by region is shown in Figure 5 for the 1-in-10 and 1-in-20 cases. The battery sizes were selected based on the instantaneous peak unserved energy in the 1-in-20 load condition observed in the PCM case after increasing the load as described. The total BESS capacity added to the cases was 11,135 MW, matching the total instantaneous peak unserved energy in the 1-in-20 case. This BESS addition was on top of the energy storage in the 2030 ADS. Each of the new batteries was assumed to supply energy for four hours, except for those in the Comisión Federal de Electricidad (CFE), Mexico, area. For the 1-in-10 load scenario, CFE batteries had six hours of storage. The CFE batteries in the 1-in-20 load scenario had eight hours of storage to fully mitigate unserved energy. The BESS duration in CFE was increased consistent with the scope and process flow of the study shown in Figure 1. In CFE, the duration of the unserved energy called for longer duration BESS. Not all areas in the studies exhibited unserved energy; batteries were only added to areas with unserved energy.

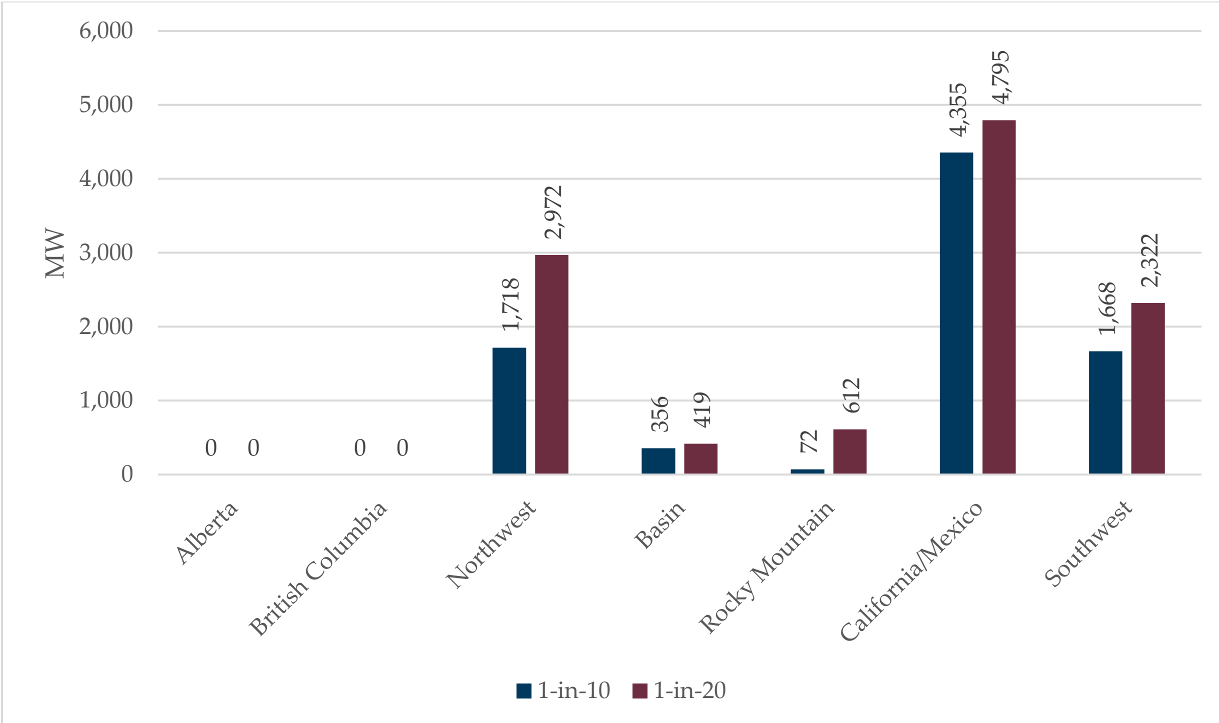

Figure 5: Peak unserved energy by region (MW)

Battery Placement

The initial approach of the study was to place the battery storage units near renewable energy sites (i.e., hybrid resources). However, there was very little renewable energy surplus with the increased loads, so the BESS were placed closer to the load centers instead to reduce transmission loading. The maximum capacity of each battery storage unit was kept under 300 MW to avoid localized transmission congestion. Each battery storage unit was placed near highly loaded buses on the high voltage side of the transformer (230 kV or higher), which had a strong transmission system.

Bonneville Power Authority (BPA) Battery Storage Placement Example

A total of 1,349 MW of battery storage was added to the BPA area, which was split into five equally sized battery storage units of 269.8 MW to stay below 300 MW each. Figure 6 shows an example of how each battery was placed. The MORROWF 115 kV bus, in green, had the largest load in the BPA area: 206.8 MW. The MORROWF 230 kV bus, in red, was therefore chosen as the location to place one of the 269.8 MW BESS. This bus had a strong transmission connection and could help distribute the energy from the added BESS.

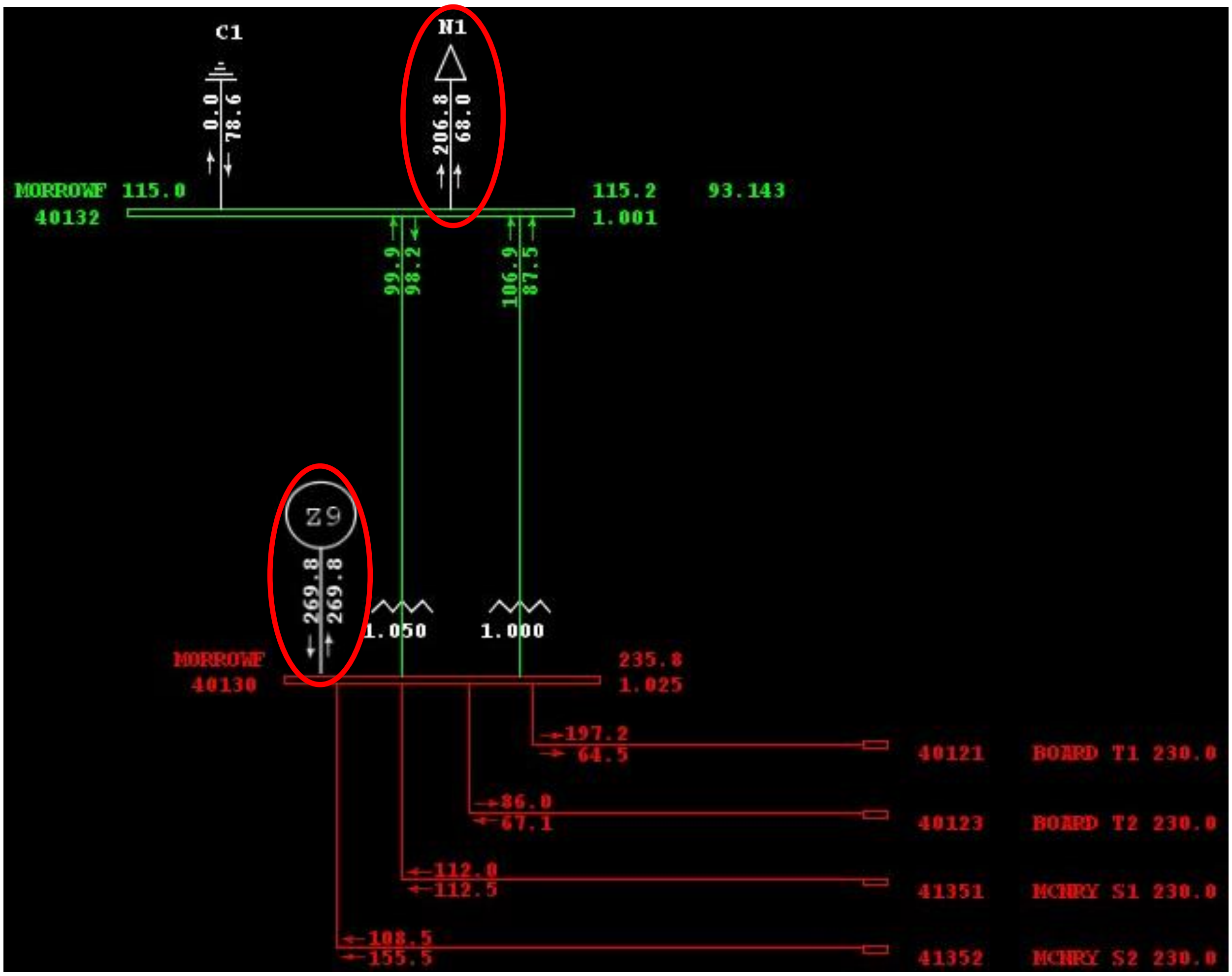

Figure 6: Example of battery interconnection in BPA system

Table 3 shows the placement of all five BESS units in BPA as well as the associated loads. The same logic was applied for placement of all BESS in all other areas that had unserved load during the two-week simulation period.

Table 3: Summary of BPA battery placement—1,349 MW

BPA Bus ID	Load (MW)	BESS Bus	BESS size (MW)
40132	206.8	40130	269.8
40127	174.1	41141	269.8
40717	161.9	40422	269.8
41047	158.7	41353	269.8
402170	128.2	42100	269.8

Dynamic Modeling and Analysis

The VLAR study also included dynamic and dynamics modeling to conduct a transient stability analysis of the system response in both steady-state and dynamics for the heat wave event modeled in the PCM.

Load Modeling

The goal in the power flow analysis was to model the same amounts of load and generation as the PCM case. Since the system topology of the grid in the power flow model was nearly identical to that of the PCM case, this resulted in similar transmission line and path flows on transmission elements of interest. The first step was to make sure that the load in the power flow matched the PCM. The case chosen for the study represented August 29 at 8:00 p.m. This case was selected for several reasons:

- Loads would be relatively high at this time of day;
- Solar generation would be near zero; and
- Batteries would be in relatively high use.

The time and date selected met all of these requirements, so a power flow dataset was exported from the PCM for this time.

To run transient stability simulations using the dynamic models, it was necessary to start from a power flow base case that had already been created and that had a good dynamic dataset associated with it. The underlying power flow chosen was the 2030 Heavy Summer (30 HS1) case. Starting with the 30 HS1, then replacing the loads in it with the loads that were exported from the PCM case, the total load in the power flow model was 170 GW.

Generation Modeling

Like the load modeling in the previous section, the generation dispatch from the PCM representing August 29 at 8:00 p.m. was exported in power flow format, then imported into the 30 HS1 power flow. Most of the generators in the PCM had a corresponding generator dynamic model. In this instance, if a specific generator was dispatched at 75 MW in the PCM, then, when the data was imported into the power flow model, the software program would find this same generator and dispatch it at 75 MW. Due to some differences in how generation is represented in PCM and power flow, there were some generators for which there was no match between the PCM and the power flow and dynamic model.[3] This mismatch between generators available in the PCM and power flow was reconciled before starting the analysis.

When parameters in a power flow are changed, as in this case, a new “solution” is required. This means that the power flow software program is able to match generation to load and calculate how power distributes itself throughout the electrical interconnection under study (in this case, the Western Interconnection). After the differences in load and generation between the PCM and power flow were reconciled, at first, solving the power flow with modified loads and resources required further adjustments. The solution[4] difficulties were caused in part by locations in the power flow where reactive power was either excessive or insufficient, which can show up in the power flow as high or low voltages. To fix these issues, reactive devices were added to adjust voltages until a good power flow solution was achieved.

Path Flows

After balancing the PCM and power flow load and generation, DC line schedules were synchronized to have similar path flows in both the PCM and power flow. Table 10 in the Appendix compares path flows in the PCM and power flow. Ideally, differences would all be close to zero. In reality, the PCM and the power flow models contain different information and are used for different purposes, so, to get closer matches in path flows, it is usually necessary to perform significant data reviews and modifications. While this is regularly done in WECC, this was not the purpose of this study. In this study, the observed path flow differences between the PCM and power flow were determined to be acceptable.

[3] A recommendation for future modeling of the ADS would be synchronizing the generation model differences between power flow and PCM.

[4] The power flow solution is used to evaluate a systematic mathematical approach to determine bus voltage, branch current, real power flow, and reactive power flow for the specified generation and load conditions. The steady-state solution or convergence of the solution is achieved when load and generation are balanced considering different equipment constraints in the system.

Assessment and Results

PCM Results

The results of PCM simulations indicate that 1-in-10 and 1-in-20 case results were similar, with the 1-in-20 results being more pronounced. The results of the 1-in-20 were chosen for the following discussion.

The PCM was run from August 22 to September 5. Unserved energy was seen in 24 of the 360 hours of the simulation period. PCM results indicate that most of the unserved energy was observed on August 29 and September 4. Figure 7 and Figure 8 show the load and generation balance with and without adding battery storage units on August 29. A similar unserved energy pattern occurred on September 4. Before adding the additional BESS, unserved energy can be observed in Figure 7 indicated by the difference between the dotted purple line and the resource stack in the evening ramp hours when solar is going off-line. The generation from existing battery and pump storage generation from the 2030 ADS is shown in red. Figure 8 shows the existing storage, along with the additional BESS represented in red, is used in the same evening hours, so the unserved energy is mitigated. The added BESS dispatch was at maximum capability (11,135 MW) during the hour (August 29, hour 20) in which the unserved load was observed to be the highest (9,606 MW) before adding the BESS.

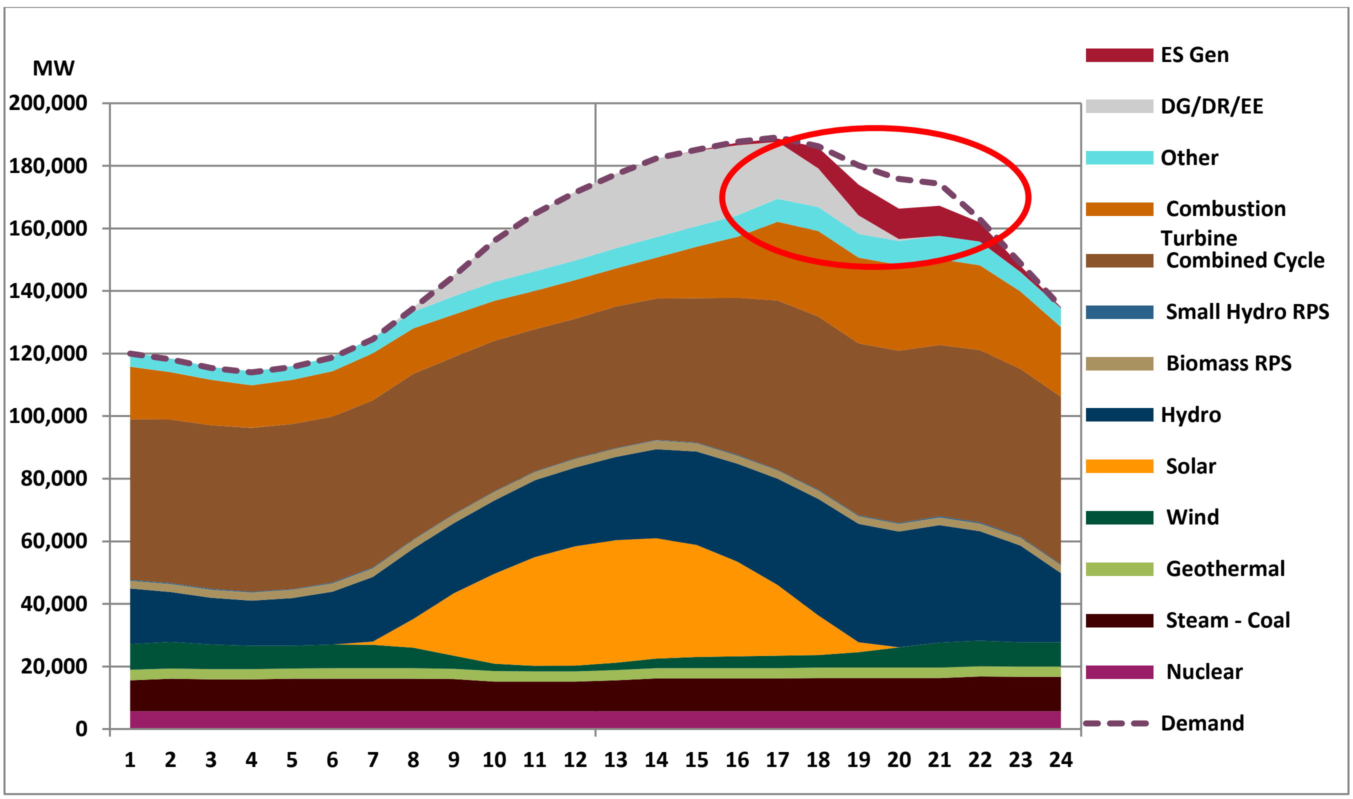

Figure 7: Load and generation balance without added BESS—with unserved energy on August 29

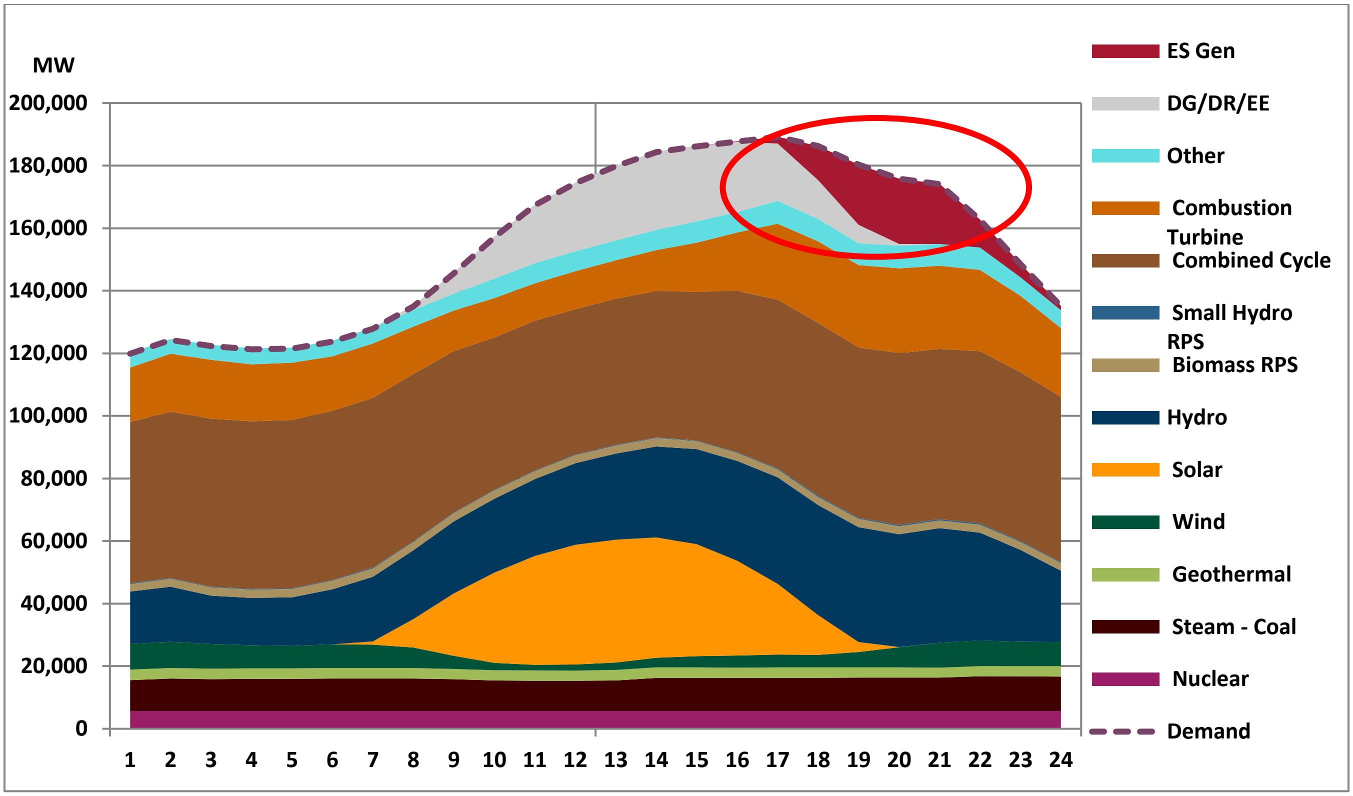

Figure 8: Load and generation balance with added BESS—no unserved energy on August 29

Figure 9 shows the correlation between added BESS, unserved energy, and locational marginal prices (LMP). During the evening ramp up periods, the added battery storage is discharging to mitigate unserved energy, and the average LMP decreases after adding BESS on a system level. PCMs do not consider the initial investment cost for resources into the LMP calculation. The model assumes that the generation portfolio is existing for the dispatch year and only considers transmission costs and generator commitment and dispatch costs such as congestion, fuel, variable operations, and maintenance. As shown in Figure 9, unserved energy (in dark blue) was observed before adding the additional BESS. The additional BESS (in light blue) is observed as discharging and covering the unserved energy during the evening ramp. The average LMP (without BESS in dashed orange, and with BESS in dashed red) is drastically reduced from $1,700/MWh to $300/MWh and $400/MWh on August 29 and September 4, respectively.

The LMP was high because there were not enough resources to meet the load during the evening ramp. Subsequently, once additional BESS was added, the evening load ramp was served, resulting in a reduced LMP.

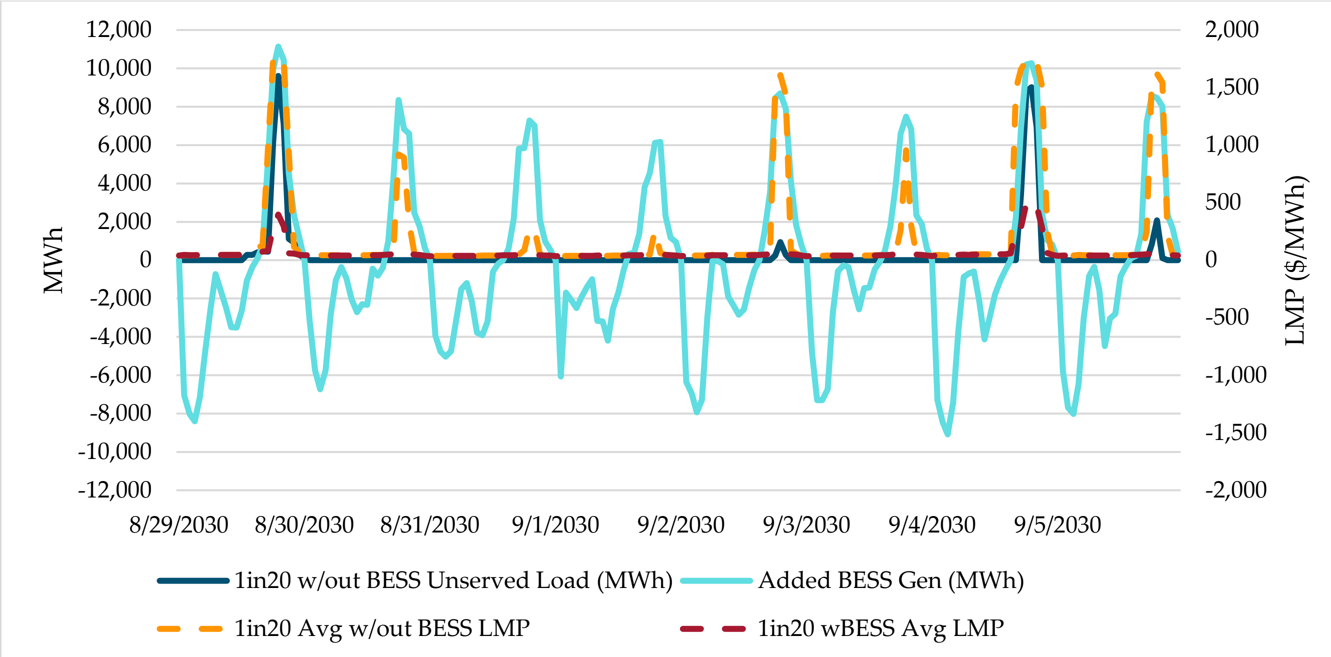

Figure 9: Unserved energy, added BESS, and LMP with and without BESS

For the two-week simulation period, Figure 10 shows the change in the energy dispatch of generating resources between the cases with and without additional BESS, as well as the pumping/charging load. The largest difference is the dispatch of the BESS to mitigate unserved energy. Some of the thermal resources also change their overall dispatch since the energy demand changes with BESS charging and discharging. The red bar, pumping/charging load, at the bottom of the chart shows the additional load for charging the BESS.

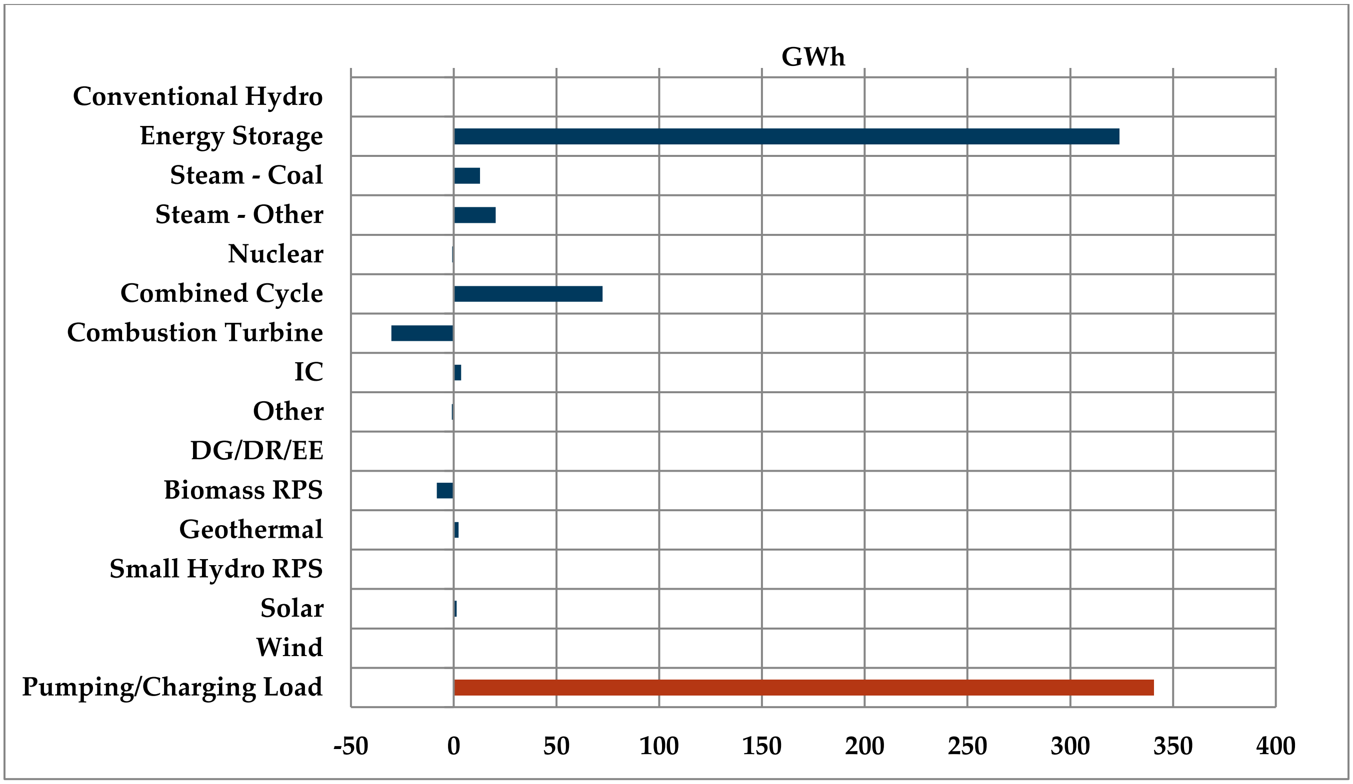

Figure 10: Change in generation 1-in-20 loads with and without BESS

Figure 11 shows when the added BESS are charging and discharging on August 29 in the following four regions represented by four areas:

- Northwest—Bonneville Power Authority (BPA)
- Northern California—Pacific Gas and Electric, Valley (CIPV)
- Southern California—Southern California Edison (CISC)
- Desert Southwest—Tucson Electric Power (TEPC)

Figure 11 exhibits, most of the charging occurs during the early morning hours with some occurring midday. Depending on the location of the added BESS, they charge at different times. For example, in BPA, BESS are charging in the early morning hours, typically from hour ending 1:00 to 7:00 a.m.; in CISC, CIPV, and TEPC, the BESS are charging during the night and day. The PCM model determines the best time to charge and discharge based on price, making it economic to operate the BESS. The dispatch method in the PCM is a daily schedule based on price for each defined area. The BESS units charge when price is low and generate when price is high and cycle each day. The BESS units generate during the evening peak hours to help with the ramping needs as well as to mitigate unserved energy.

The system's total curtailed energy was minimal before and after adding the BESS because the simulation was run during a period of high demand. After adding BESS, the generation dispatch changes to account for charging and energy generation from BESS. The impact of BESS charging and discharging on other resources depends on the area, day, and hour. For example, in BPA, hydro generation increases during the hours when BESS charges and reduces when BESS generates.

It was also observed that some existing storage devices in the 2030 ADS—pump storage and batteries—were used less after running the simulation with the added BESS. The added BESS affects the LMP at the bus and in the area where BESS was added, affecting the use of other generation. Added BESS units will make the LMP gap smaller between resources causing the existing energy storage to be used less. The transmission loading impact is minimal for the generation dispatch for the added BESS, as they are placed near the load centers, giving them a possible advantage over existing storage devices.

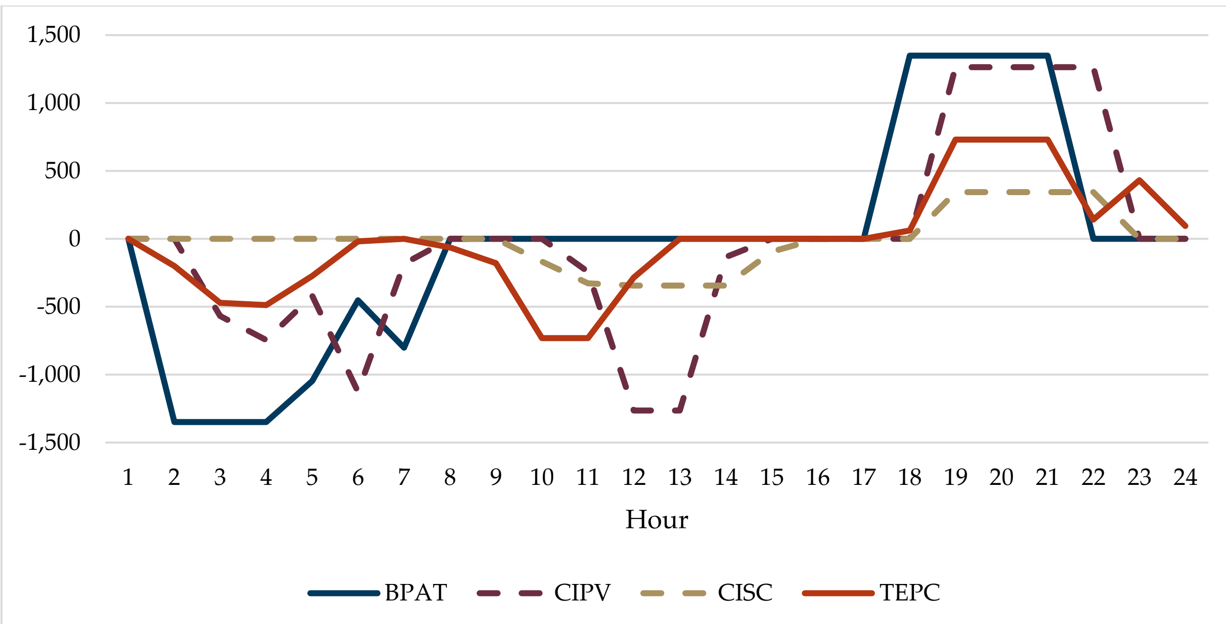

Figure 11: BESS usage on August 29, 2030—select areas

Figure 12 shows the inter-regional energy transfers with and without adding battery storage. Total imports into California were reduced by 109 GWh (2.7%) after adding additional BESS. Energy in and out of Basin also decreased by approximately 33%. Overall, total energy transfer between different regions of WECC was reduced, meaning there was lower utilization of inter-regional transmission and higher dependency on local transmission networks.

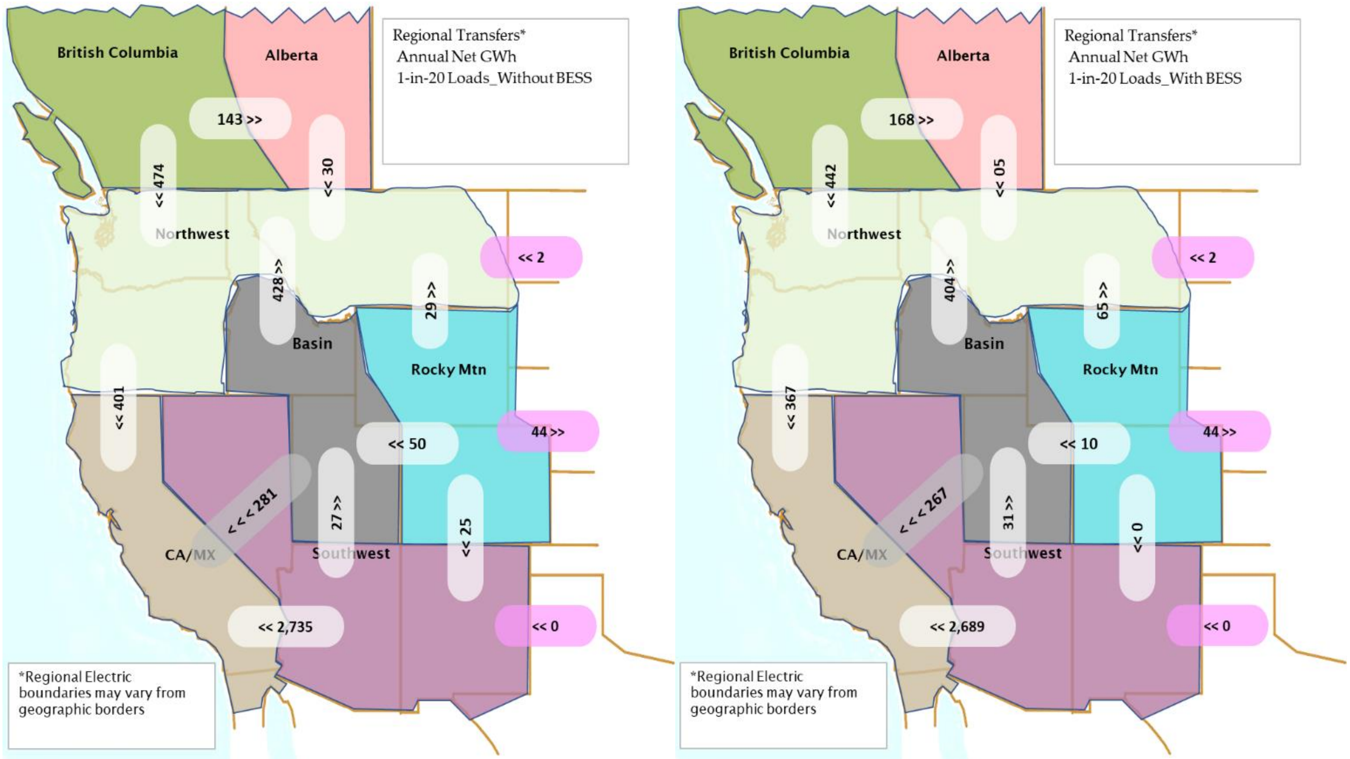

Figure 12: Regional transfers with and without BESS

With the addition of BESS, overall system-wide energy transfers between different regions were reduced except for transfers into Alberta from British Columbia. Except for transfers in and out of Basin, the overall impact on the BESS on regional transfers was minimal for the simulated two-week period.

BESS Impact on Ancillary Services

Although ancillary services (AS) were not a focus of this assessment, we did observe that adding BESS affected AS performance, so these impacts are discussed briefly below. AS assist the grid operators in maintaining system balance. AS include regulation and the contingency reserves: spinning, non-spinning, and, in some regions, supplemental operating reserve (i.e., load-following).

Figure 13, Figure 14, Figure 15, and Figure 16 show the number of hours during the two-week simulation during which the modelled AS[5] (in the PCM model) were not being served (number of binding hours) with and without BESS. Adding BESS reduced the number of hours when the "load-

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

following[6] up and regulation[7] up" requirements were not served system wide by 75% and 78%, respectively. Adding BESS also reduced the number of hours in which both the "load-following down and regulation down" requirements were not served system wide by 42%. With the addition of BESS, the number of hours in which "spinning reserve [8] requirements" were not being met was reduced by 70% system wide. For spinning reserve, most BAs in the interconnection are part of reserve sharing groups as defined in Table 7 in the Appendix. Figure 13 shows the combined reserve sharing groups as modeled in the PCM. The BA's abbreviations are defined in Table 8 of the Appendix.

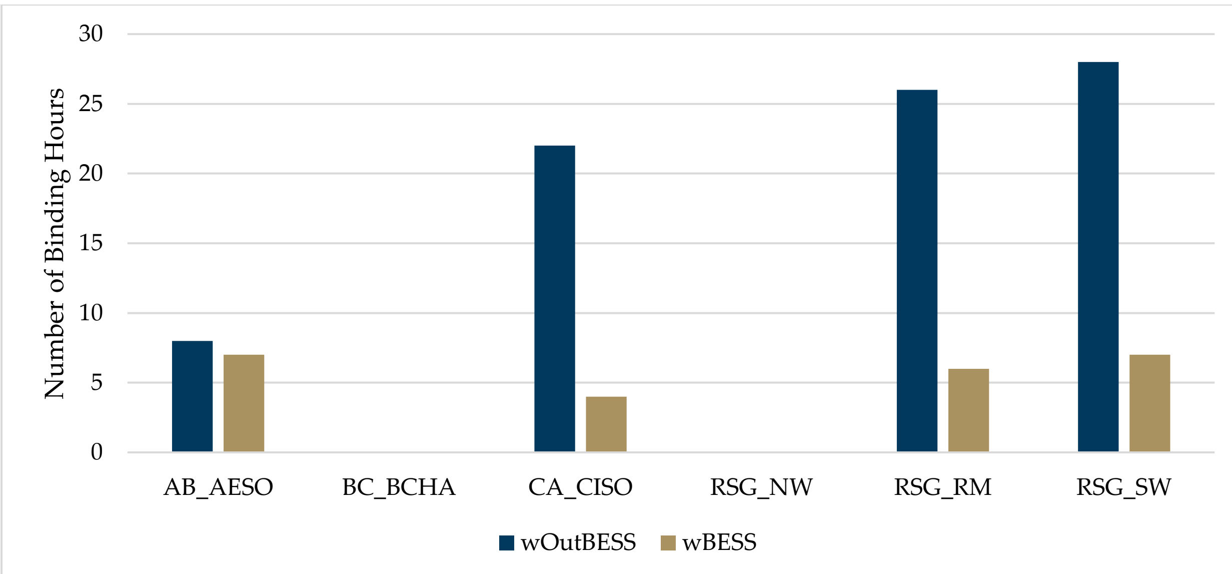

Figure 13: Spinning reserve by region and reserve sharing group binding hours with and without BESS

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

[7] For a definition of *regulation ancillary services*, see "Estimating Potential Revenue from Electrical Energy Storage in PJM," Introduction, para. 3 and 4.

[8] For a definition of *spinning reserve ancillary services*, see "Transactive Control and Coordination of Distributed Assets for Ancillary Services," Sec. 2.1.

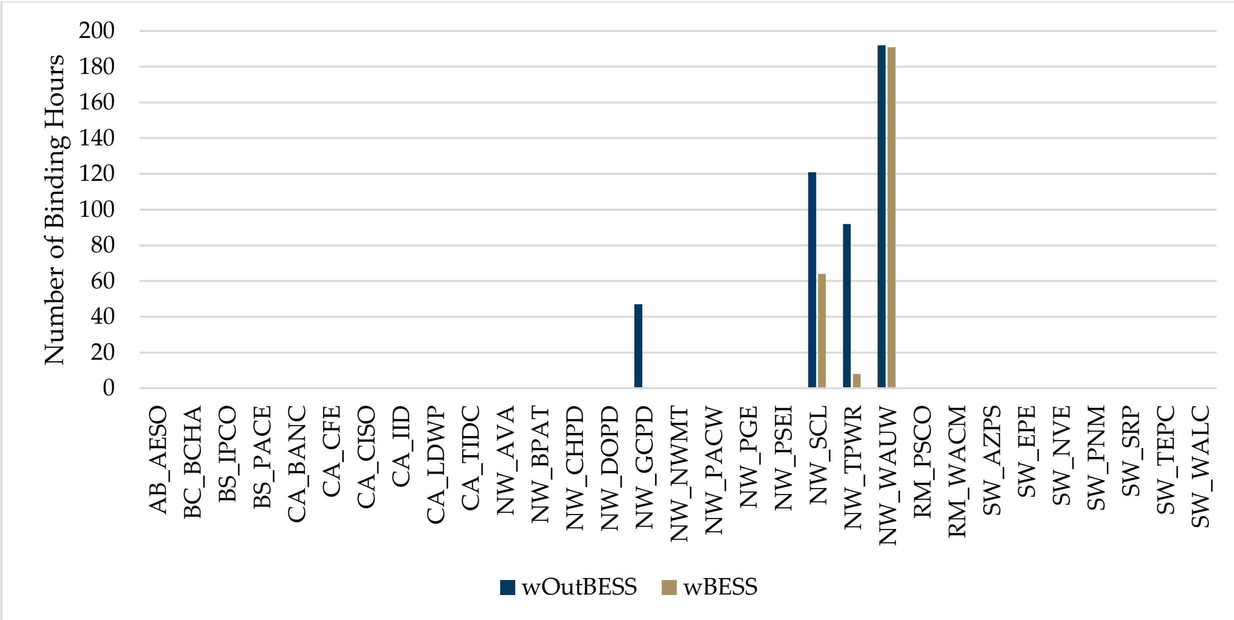

Figure 14: Regulation and load-following down binding hours with and without BESS

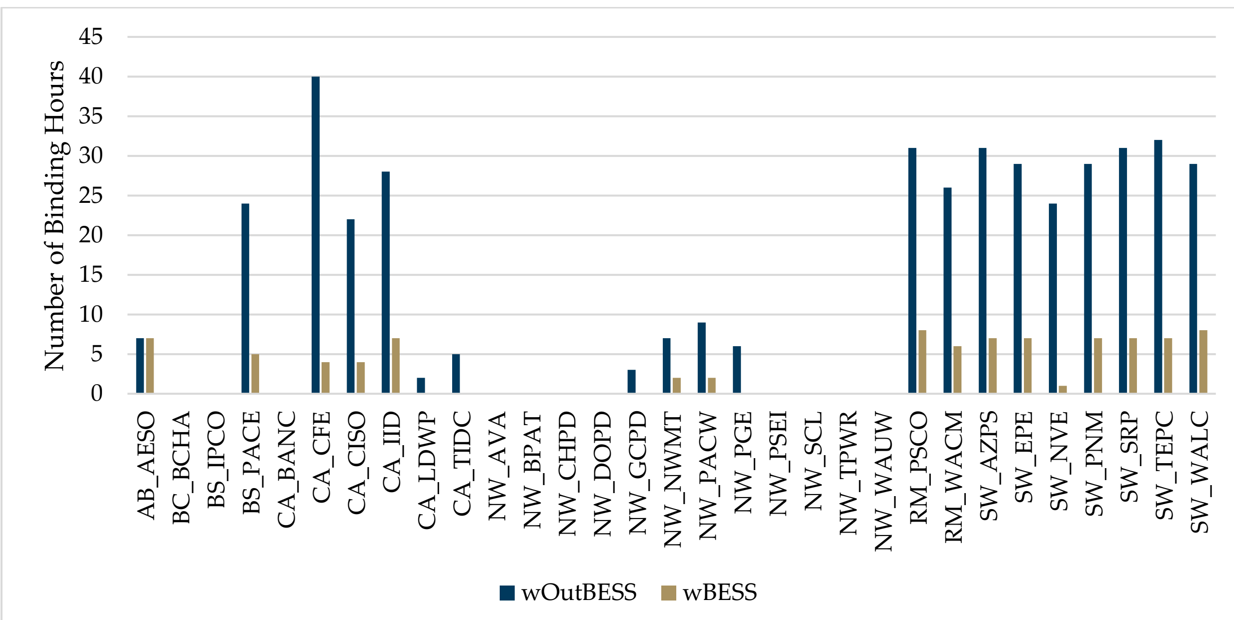

Figure 15: Regulation up binding hours with and without BESS

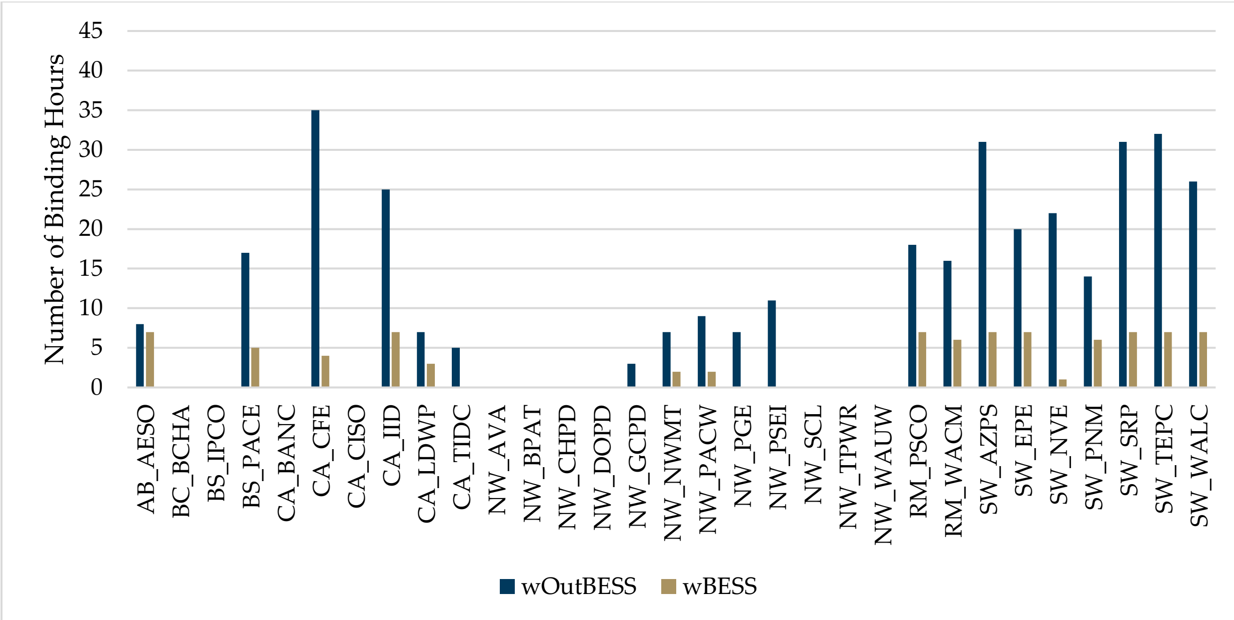

Figure 16: Load-following up binding hours with and without BESS

Transient Stability and Dynamic Simulation Results

The results of the dynamic analysis focused on the transient stability simulations of frequency response in the different regions with and without batteries. The power flow study applied a double Palo Verde outage. Palo Verde units 1 and 2 were tripped for a total loss of 2,745 MW of generation. The outage was simulated using the GE PSLF program v 22.0.1 and was allowed to run for 35 seconds. The frequency response was recorded at one bus in each of the subregions identified in this report. Buses were selected close to large load centers to capture the influence of loads. Frequency response is captured in the graphs below by showing the frequency plots at buses in the following subregions: Northwest, California–Mexico, Southwest, Rocky Mountains, and Basin. In each subregional graph, results for two different simulations are included.

The five figures below contain frequency traces by subregion. In each figure, the blue trace shows results from the case containing batteries with no frequency response capability, and the gold trace shows results from the case containing batteries that are frequency responsive. As expected, the case without frequency response capability exhibits the lesser frequency response of the two simulations.

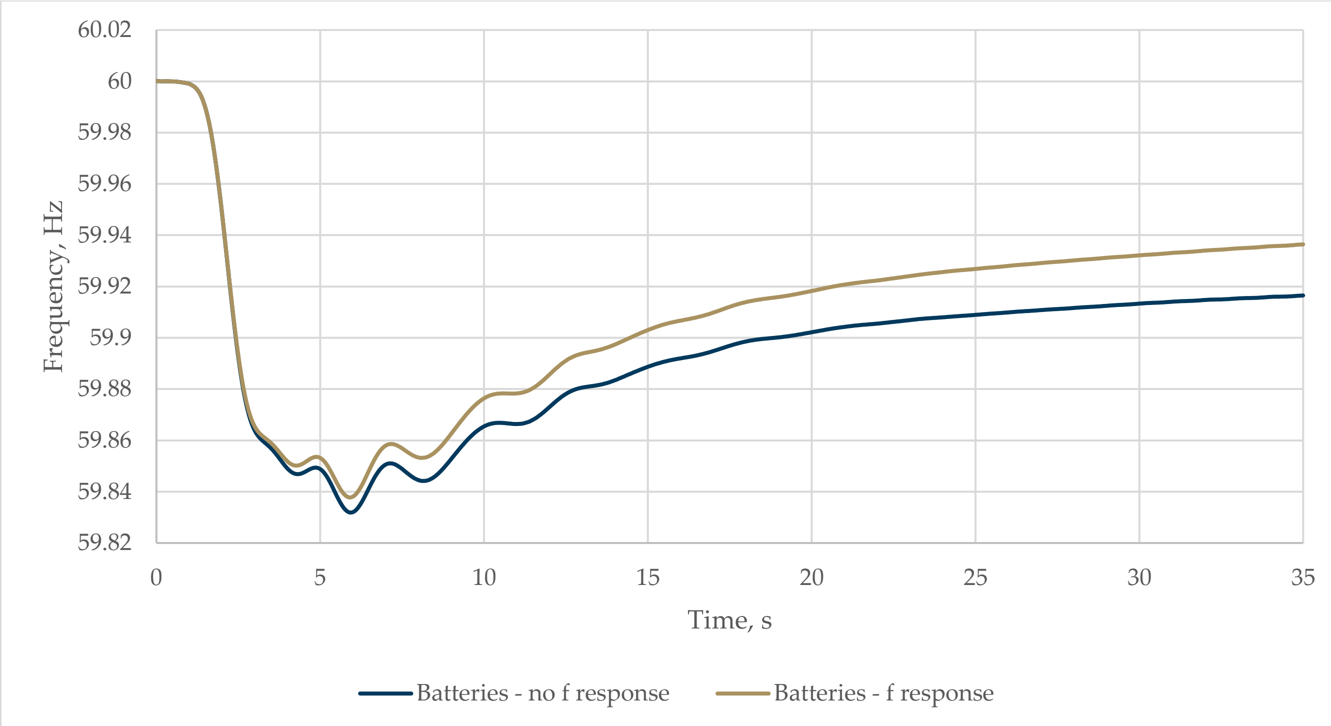

Figure 17: Frequency—Northwest (RIVRGATE 230 kV)

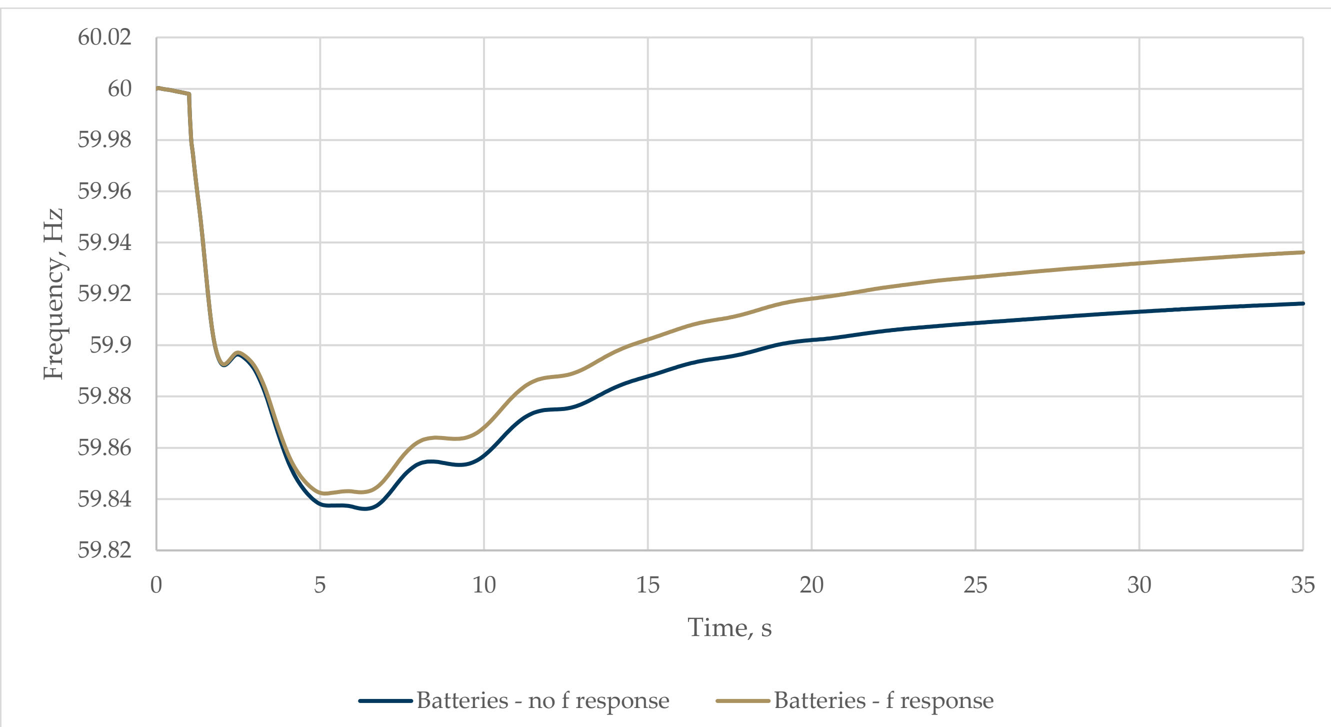

Figure 18: Frequency—CA/MX (Chino 230 kV)

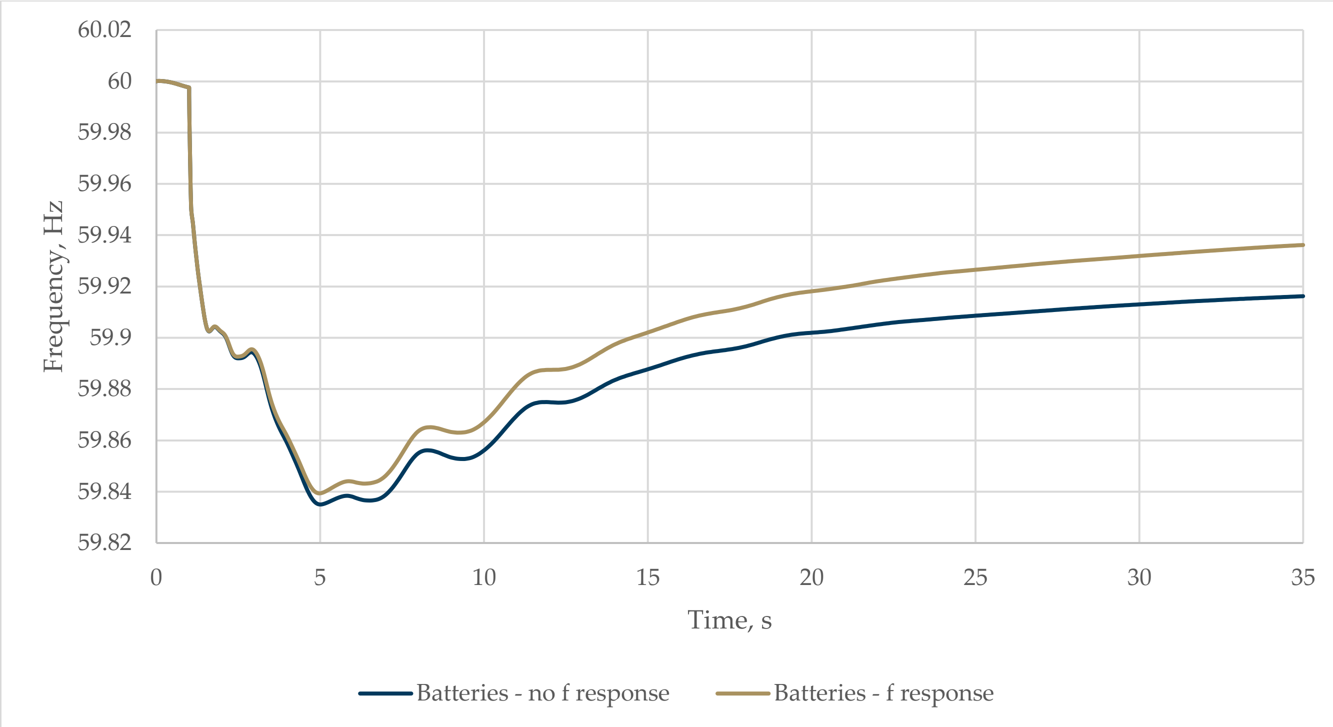

Figure 19: Frequency—Southwest (Santan 230 kV)

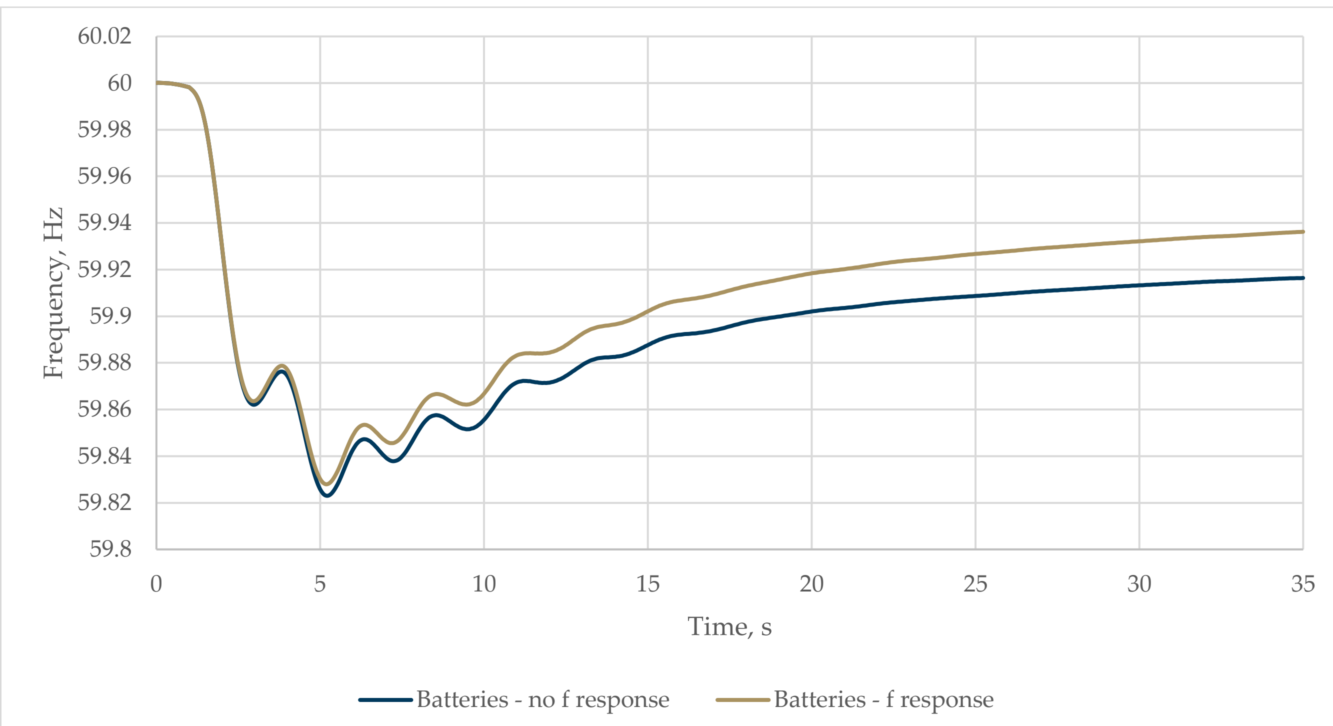

Figure 20: Frequency—Rocky Mountains (Cherokee 230 kV)

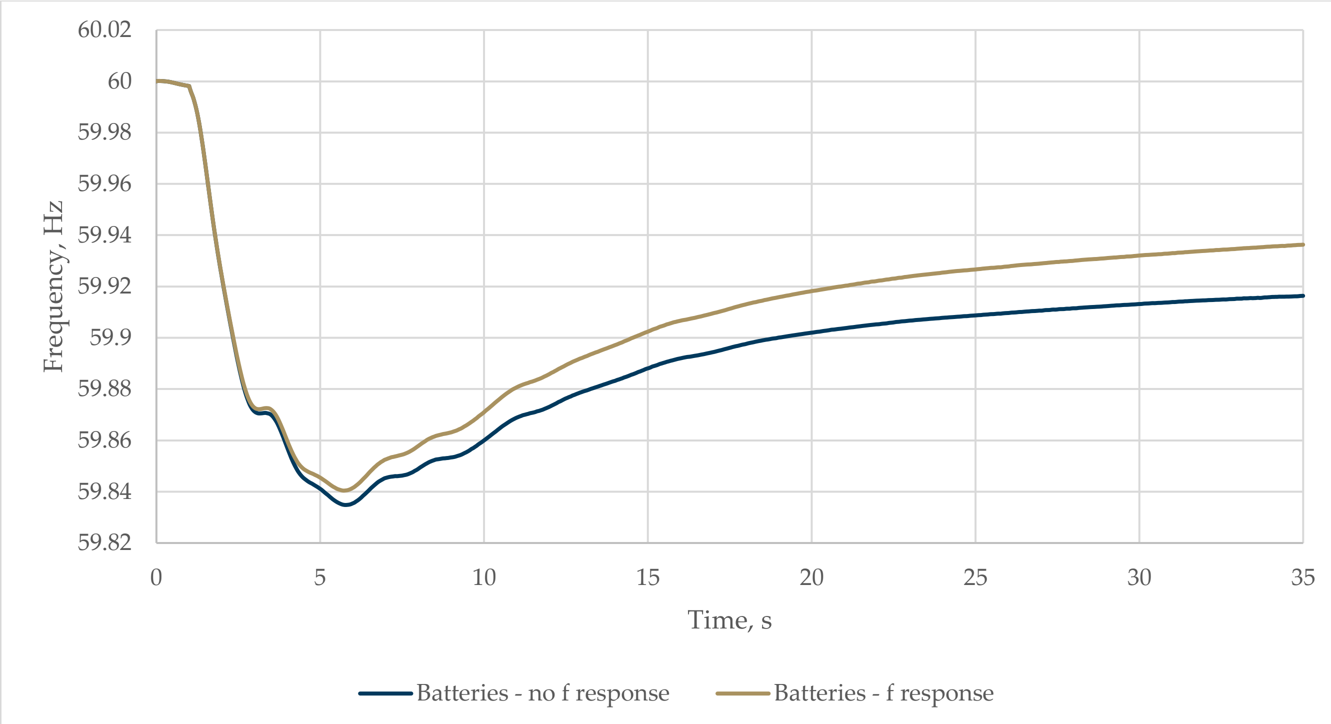

Figure 21: Frequency—Basin (Terminal 345 kV)

Conclusions

- The PCM results indicate that, with an adverse heat wave event[9] and additional retirement of 3,065 MW of coal generation[10], there could be unserved energy in most areas across the interconnection for the 2030 planning horizon.
- According to the analysis, BESS may be effective in reducing unserved energy as renewable energy implementation increases.
- The BESS were sized according to the peak unserved energy in each area. Typical four-hour BESS were able to mitigate the unserved energy, except for CFE, where six-hour and eight-hour BESS was needed in 1-in-10 and 1-in-20 cases, respectively.
- Other generation was dispatched differently in different regions throughout the day to account for BESS charging.
- Adding BESS produced a minimal impact on the regional transfers, except for exports from the Rocky Mountain area.

[9] A 1-in-20 heat wave scenario was modeled for the peak demand period for the study.

[10] These additional retirements represent further updates from PacifiCorp's 2019 Integrated Resource Plan and from the U.S. Energy Information Administration.

    - It is challenging to quantify the impact on regional transfers, as the PCM simulation was run only for a two-week period.
- The BESS helped to reduce the AS binding hours throughout the interconnection.
- Results from the dynamic simulations show that the frequency response of the system is better with batteries that provide frequency response, although frequency response improvements weren’t significant.
- Simulated study results are in line with the expectation that inverter-based resources such as BESS can be used to provide valuable AS to complement load-serving capability.
- There are other aspects of power system operation that could benefit from battery systems, such as the ability to provide ramping capability.
- The scope of this study was limited, leaving room for potential further investigations with different scenarios and parameter settings to be explored in future dynamic studies.
- In the dynamic analysis in this assessment (with the given system parameters), the results show that a double Palo Verde outage with high renewable penetration, with or without the addition of BESS, does not lead to underfrequency load shedding.

Recommendations

- WECC recommends that entities study the variability in electric load and generation, evaluate the reliability risks, and assess the potential uses of BESS.
- Suggestions for future assessment work:
    - Perform a full year PCM run with the additional BESS modeled in the study case to see the impact during the time without the heat wave. In doing this, evaluate whether BESS could:
        - Further offset some thermal generation;
        - Reduce curtailment of renewable generation;
        - Provide energy during evening ramp on most days of the year; and
        - Reduce the average system LMP.
    - Simulate a cold weather event on a regional or system level.
    - Perform further simulations to investigate a detailed impact on the AS with the BESS.
    - Study the impact from regional heat waves with hybrid BESS systems modeled (i.e., BESS co-located with renewable resources) from a full year PCM run.
- The Anchor Power Flow Work Group (APFWG), Production Cost Data Subcommittee (PCDS), and Reliability Assessment Committee (RAC) should establish the same generation resource definitions for PCM and power flow to perform more consistent power flow, stability, and dynamic simulations.

Contributors

WECC wants to thank the following people and organizations for the hard work and time they invested in the Variability of Loads and Resources Advisory Committee:

- Radha Soorya, Long Road Energy, Chair
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- Richard Marrs, Quantum Planning Group
- Gerald Harris, Quantum Planning Group
- Thomas Carr, Western Interstate Energy Board
- Effat Moussa, San Diego Gas and Electric
- Chifong Thomas, Thomas Grid Advisor

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Appendix

Table 4:Peak Load for 1-in-10 and 1-in-20

Area	2030 ADS	1-in-10	1-in-20	Area	2030 ADS	1-in-10	1-in-20
AESO	12,289	13,159	13,393	NEVP	6,392	6,844	6,966
AVA	2,141	2,293	2,333	NWMT	1,934	2,071	2,108
AZPS	8,439	9,036	9,197	PACW	3,592	3,846	3,915
BANC	4,684	5,104	5,289	PAID	1,143	1,224	1,246
BCHA	9,048	9,688	9,861	PAUT	7,863	8,419	8,570
BPA	9,607	10,287	10,470	PAWY	1,336	1,431	1,456
CFE	4,232	4,531	4,612	PGE	3,529	3,779	3,846
CHPD	266	285	290	PNM	2,740	2,934	2,986
CIPB	8,390	8,930	9,073	PSCO	9,322	9,982	10,160
CIPV	13,284	14,125	14,346	PSEI	3,747	4,012	4,084
CISC	25,868	27,509	27,964	SCL	1,187	1,271	1,294
CISD	5,021	5,473	5,523	SPPC	2,097	2,245	2,285
DOPD	312	334	340	SRP	8,870	9,498	9,667
EPE	2,233	2,391	2,434	TEPC	3,384	3,623	3,688
GCPD	1,481	1,586	1,614	TIDC	636	693	718
IID	1,248	1,306	1,312	TPWR	583	624	635
IPFE	601	644	655	VEA	170	185	187
IPMV	1,154	1,236	1,258	WACM	4,117	4,408	4,487
IPTV	2,425	2,597	2,643	WALC	1,791	1,918	1,952
LDWP	7,801	8,560	8,758	WAUW	152	163	166

Table 5: Total Unserved Energy by Area

	Hours		Total Unserved Energy (MWh)			Hours		Total Unserved Energy (MWh)	
Area	1-in-10	1-in-20	1-in-10	1-in-20	Area	1-in-10	1-in-20	1-in-10	1-in-20
AVA	6	9	87	119	NWMT	4	6	168	338
AZPS	6	13	433	917	PAUT	1	4	193	705
BANC	6	8	1,105	1,772	PAWY	2	5	8	28
BPA	6	8	2,130	5,850	PGE	6	8	2,539	4,902
CFE	14	14	6,644	7,770	PNM	5	7	921	1,953
CIPB	6	10	5,229	7,682	PSCO	5	8	119	755
CIPV	6	12	5,179	7,866	PSEI	4	7	14	537
CISC	6	9	2,050	3,072	SCL	0	4	0	276
CISD	6	10	1,563	2,215	SPPC	5	7	672	1,333
EPE	0	1	0	55	SRP	2	5	572	2,663
GCPD	6	7	293	1,485	TEPC	6	15	2,072	4,522
IID	6	9	485	668	TIDC	6	8	678	839
IPFE	2	3	91	146	TPWR	0	3	0	257
IPMV	3	5	27	48	WACM	4	9	69	1,039
IPTV	3	5	298	466	WALC	0	1	0	22
NEVP	4	6	96	267					

Table 6: Battery Sizing

Area	1-in-10 Peak Unserved Energy (MW)	1-in-20 Peak Unserved Energy (MW)	BESS Pmax (MW)	# of Buses	Area	1-in-10 Peak Unserved Energy (MW)	1-in-20 Peak Unserved Energy (MW)	BESS Pmax (MW)	# of Buses
AVA	14.5	14.5	15	1	NWMT	63.8	83.2	84	1
AZPS	73.2	88.8	89	1	PAUT	192.8	245	245	1
BANC	251.6	261.8	262	1	PAWY	4	12.5	13	1

BPA	668.9	1,348.9	1,349	5
CFE	1,109.8	1,188.5	1,189	4
CIPB	982.4	1,215.1	1,216	4
CIPV	1,147.6	1,263.2	1,264	5
CISC	343.6	343.6	344	2
CISD	305.5	305.5	306	2
EPE	0	55.3	56	1
GCPD	198.4	384.8	385	2
IID	89	91.5	92	2
IPFE	50.5	52.4	53	1
IPMV	9.5	9.5	10	1
IPTV	99.4	99.4	100	1
NEVP	46	54.6	55	1
PGE	768.6	769.2	770	3
PNM	393.8	421.8	422	2
PSCO	46.7	304.8	305	2
PSEI	3.5	172.2	173	3
SCL	0	69.1	70	1
SPPC	302.2	385.5	386	3
SRP	486.4	563.6	564	3
TEPC	366.7	730.7	731	4
TIDC	125.9	125.9	126	3
TPWR	0	130.4	131	3
WACM	25.3	307.5	308	2
WALC	0	22	22	1

Table 7: Reserve Sharing Group Definition

Combined Area-Region Name	Region Name
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_BPA

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

Table 8: Balancing Authority Definition

BA	Balancing Authority Definition
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	California—Comision Federal de Electricidad
CA_CISO	California—California Independent System Operator
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_BPA	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

BA	Balancing Authority Definition
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 9: Load Area Definition

Load Area	Load Area Definition
CIPB	CISO—Pacific Gas and Electric, Bay Area
CIPV	CISO—Pacific Gas and Electric, Valley Area
CISC	CISO—Southern California Edison
CISD	CISO—San Diego Gas and Electric
LDWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
TIDC	Turlock Irrigation District
BANC	Balancing Authority of Northern California
VEA	Valley Electric Association

Table 10: Difference in Path Flows - PCM vs. Power Flow

interface data [70]	8-29 hr 20 PCM output	Power Flow
1 "ALBERTA—BRITISH COLUMBIA "	-1200.0	-988.2
2 "ALBERTA—SASKATCHEWAN "	0.1	0.1
3 "NORTHWEST—CANADA "	-200.0	-2869.2
4 "WEST OF CASCADES—NORTH "	1743.7	2060.7
5 "WEST OF CASCADES—SOUTH "	2768.0	2638.1
6 "WEST OF HATWAI "	-781.7	-552.0
8 "MONTANA—NORTHWEST "	-1043.2	-989.7
15 "MIDWAY—LOS BANOS	-3228.0	-3176.3
16 "IDAHO—SIERRA	-69.0	-40.9
17 "BORAH WEST	-109.2	-190.3
18 "MONTANA—IDAHO	65.3	-170.7
19 "BRIDGER WEST	1125.8	1057.6
20 "PATH C	1127.6	1132.0
22 "SOUTHWEST OF FOUR CORNERS	1176.3	1044.4
23 "FOUR CORNERS 345/500	-7.0	-28.6
24 "PG&E—SPP	81.2	-2.8
25 "PACIFICORP/PG&E 115 KV INTERCON.	50.4	37.3
26 "NORTHERN—SOUTHERN CALIFORNIA	4000.0	3930.4
27 "IPP DC LINE	573.2	575.5
28 "INTERMOUNTAIN—MONA 345 KV	274.6	268.7
29 "INTERMOUNTAIN—GONDER 230 KV	-22.6	-17.1
30 "TOT 1A	-117.8	-47.9
31 "TOT 2A	143.2	143.1
32 "PAVANT, INTRMTN—GONDER 230 KV	-59.5	-52.9
33 "BONANZA WEST	106.7	-160.8
35 "TOT 2C	-207.5	-19.2
36 "TOT 3	924.8	836.5
37 "TOT 4A	-16.3	-7.6
38 "TOT 4B	-21.6	-10.2
39 "TOT 5	-417.9	-108.5
40 "TOT 7	-342.6	71.1
41 "SYLMAR—SCE	-216.3	-262.4
42 "IID—SCE	367.6	315.4
45 "SDG&E—CFE	286.4	-264.6
46 "WEST OF COLORADO RIVER (WOR)	5019.1	4818.5
47 "SOUTHERN NEW MEXICO (NM1)	-608.4	-605.4
48 "NORTHERN NEW MEXICO (NM2)	839.6	829.0
49 "EAST OF COLORADO RIVER (EOR)	2718.7	2571.0
50 "CHOLLA—PINNACLE PEAK	617.2	582.8
51 "SOUTHERN NAVAJO	11.5	-30.6
52 "SILVER PEAK—CONTROL 55 KV	5.0	-19.7
54 "CORONADO—SILVER KING—KYRENE	843.9	802.1
58 "ELDORADO—MEAD 230 KV LINES	-91.6	-107.3
59 "WALC BLYTHE—SCE BLYTHE 161 KV	92.5	87.2
60 "INYO—CONTROL 115 KV TIE	18.9	-51.7
61 "LUGO—VICTORVILLE 500 KV LINE	102.4	-18.7
62 "ELDORADO—MCCULLOUGH 500 KV	0.1	353.6
65 "PACIFIC DC INTERTIE (PDCI)	914.0	914.9
66 "COI	-47.4	-214.6
71 "SOUTH OF ALLSTON	2060.6	1579.0

interface data [70]	8-29 hr 20 PCM output	Power Flow
73 "NORTH OF JOHN DAY	3030.9	3099.1
75 "MIDPOINT—SUMMER LAKE	-550.0	-782.8
76 "ALTURAS PROJECT	-27.9	-115.8
77 "CRYSTAL—ALLEN	434.2	319.0
78 "TOT 2B1	16.3	73.7
79 "TOT 2B2	35.9	-3.9
80 "MONTANA SOUTHEAST	-9.9	-54.7
81 "SNTI-S.NEVADA TRAN INTERFACE	-1939.1	-1396.7
82 "TOTBEAST	1614.6	1874.5
83 "MATL	-45.1	-164.0