WECC

Impact of High Distributed Energy Resources

Jon Jensen and Nick Hatton

March 4, 2022

Executive Summary

This assessment analyzed the impacts of high penetrations of distributed energy resources (DER) on the Western Interconnection. Modeling for this analysis started with the 2030 Anchor Data Set (ADS), and additional DER were added without replacing existing resources. DER in this assessment was assumed to be behind-the-meter (BTM[1]) rooftop solar. The additional DER units added to the 2030 ADS for this study were distributed by load areas and buses as a percentage of load at each bus. DER were specified as a "must-take" resource with an hourly shape in the simulation, which means that power generated by DER was dispatched directly without regard to a dispatch price and could not be curtailed in the simulation. The study assumed increased DER levels based on per capita DER levels for each state in 2030 ADS. The amount of DER added for this study was not intended to be a forecast, but to assess how the bulk power system would perform if significantly higher levels of DER were realized.

The following cases representing various levels of DER penetration in the production cost model (PCM[2]) were assessed:

- 2030 ADS PCM V2.2.1 (9% of the installed generation capacity is DER);
    - This case was the starting point to build the cases below;
- 2030 ADS PCM 20% DER (20% of the installed generation capacity was DER);
- 2030 ADS PCM 35% DER (35% of the installed generation capacity was DER); and
- 2030 ADS PCM 35% DER Redistributed (35% of the installed generation capacity was DER. 50% of California DER capacity from the 2030 ADS PCM 35% DER case was redistributed to the rest of the system); and
- 2030 ADS PCM 35% DER Redistributed 400MWx4hr (the 2030 ADS PCM 35% DER Redistributed case with the addition of 400 MW x 4-hour battery storage added to each of the areas).

The battery configurations considered for this study were 400 MW x 4-hour battery, and 200 MW x 8-hour battery. The study showed that the 400 MW x 4-hour battery configuration was superior because it resulted in a larger decrease in thermal energy and a larger increase in battery storage use than the 200 MW x 8-hour battery configuration.

---

[1] Energy production and storage systems that directly supply homes and buildings with electricity. Residential and utility-scale solar panels are considered behind-the-meter, as are residential and utility-scale batteries—the energy that is produced and stored by these systems is separate from the grid and is not counted by a meter before being used.

https://www.bostonsolar.us/solar-blog-resource-center/blog/what-does-behind-the-meter-mean/

[2] Or economic dispatch model. Used to model the power system by minimizing costs as well as obeying the operating constraints of the system.

The voltage profile shifts and transient stability impacts of the high penetration of DER were assessed in a case with 20% of load served by DER in power flow and stability analyses. Steady-state voltage profiles increased in magnitude in the 20% DER case. Transient stability analysis showed that the increased DER exacerbated voltage-related load loss in some cases, but in other cases, it decreased the load loss.

Modeling runs showed that increasing DER generally decreases the output of thermal units and increases curtailment of utility-scale solar and wind resources. This was due in part to the modeling assumption that DER could not be curtailed. For all studied cases, some thermal units stayed on during the day when they would not normally be needed—this was due to system and reliability requirements such as "Must Run" assignments and unit commitment requirements. For example, if a generating unit was needed in the morning, but not needed in the middle of the day, and needed again during the afternoon ramp, it may not have enough time to turn off and on again due to the minimum down-time constraints. If the generator minimum down-time is longer than the time the unit would be turned off, then the generator would stay online and not turn off. This is an example of a unit commitment requirement forcing a generating unit to stay on even when it is not needed.

In general, reduction of thermal generation output was seen in all the cases when compared to the 2030 ADS PCM V2.2.1, however the 35% DER case showed an increase in combustion turbine (CT) gas generation. In the 35% DER case, the CT resources were a more favorable dispatch option, due to their fast-ramping capability, which is a necessary characteristic when solar production drops off at the end of the day.

Adding battery storage to the high DER case decreased curtailment of the solar and wind generation. During the daylight hours, surplus wind and solar generation charged the batteries for use later in the day rather than curtailing it. Battery additions also showed a noticeable decrease in fast ramping natural gas resources (CT and combined cycle). Since the batteries were able to contribute to the evening ramp as the sun sets.

Another interesting observation concerned the impact of high penetration of DER to locational marginal pricing (LMP[3]). In the 35% DER case, LMPs became negative during daylight hours in some areas. This means that the energy was being produced in excess of demand and therefore the value of the energy decreased so much that it became negative. There could be economic impacts if large amounts of DER are added to the system. A careful examination of planned generation will be necessary to realize the policy objectives of high DER penetration. These considerations could include market/rate design, management systems of resources, addition of battery storage or hybrid (e.g.,

[3] The value of energy at different locations, based on generation supply, load demand, transmission utilization, and other system constraints.

solar/wind plus battery) systems. However, the addition of battery storage to the high DER case brought the average generation LMPs back to positive values.

The increase in DER also affected some path flows. More paths had flow reversals in high DER cases compared to the 2030 ADS PCM V2.2.1. For example, Path 66 (California–Oregon Intertie) flows reversed from typical north-to-south flows to south-to-north flows more frequently in the high DER cases than in the 2030 ADS PCM V2.2.1.

To reliably plan and operate the system at higher penetration levels of DER, careful planning will be important. Without careful planning, significant impacts to grid-level generation could be observed, including economic impacts, increased ramping requirements and difficulty maintaining voltages within reasonable levels.

Table of Contents

Purpose

The purpose of this study is to identify potential reliability risks to the Bulk Power System (BPS) in the Western Interconnection resulting from high levels of penetration of distributed energy resource (DER) on the system. This study added DER to the system without replacing any existing resources. The DER in this assessment were considered behind-the-meter (BTM) rooftop solar.

The Distributed Energy Resources Advisory Group (DERAG) guided the modeling steps for this assessment. DERAG members consisted of WECC staff and stakeholders. The DERAG sought to evaluate impacts of high penetrations of DER on the system. Key reliability metrics included—

- Generation mix;
- Transmission flows;
- Locational marginal pricing (LMP);
- Frequency response;
- Transient voltage recovery;
- Potential transmission congestion;
- Steady-state stability;
- Transient stability during dynamics outages.

Reliability Risk Priorities

The Reliability Risk Priorities addressed in this assessment were:

- Resource adequacy and performance;
- Changing resource mix; and
- Distribution system and customer load impacts on the Bulk Power System.

Key Reliability Questions

This assessment set out to answer the following reliability questions:

- What effect could high levels of DER have on the resource flexibility and system stability of the BPS?
    - What amount of DER causes reliability concerns?
- How might DER dispatch affect reliability?
- How does a significant increase in DER affect the system?
    - How will the presence of large amounts of DER change the steady-state behavior of the system?
    - How will DER respond dynamically, considering a large system disturbance?

Key Assumptions

The following cases were studied for this assessment:

- 2030 Anchor Data Set (ADS) PCM V2.2.1 (9% of the generation capacity was DER);
  - This case was the starting point to build the cases below;
- 2030 ADS PCM 20% DER (20% of the installed generation capacity was DER);
- 2030 ADS PCM 35% DER (35% of the installed generation capacity was DER);
- 2030 ADS PCM 35% DER Redistributed (35% of the installed generation capacity is DER);
  - To build this case, 50% of California DER capacity from the 2030 ADS PCM 35% DER case was redistributed to the rest of the system;
- 2030 ADS PCM 35% DER Redistributed 400MWx4hr (the 35% DER Redistributed with the addition of 400 MW x 4-hour battery storage added to each of the areas).

A case built with 20% of load served by DER was also assessed in power flow and dynamics.

DER Assumptions

For all cases—

- DER were considered BTM rooftop solar modeled on the generation side in the PCM;
- DER were modeled as a "must-take" resource; this does not allow the DER to be curtailed;
- DER followed the solar generation profile shapes for its area;
- DER levels studied were based on per capita DER levels seen in high adoption areas (California and Arizona) and applied to other areas in the Western Interconnection;
- DER were distributed to each area by load bus. This allows DER to be concentrated in areas with higher loads.

Other Assumptions

- Battery storage was modeled as grid-scale energy storage. GridView[4] optimized battery charging and discharging based on production cost during simulation runs;
- An equal amount of battery storage was distributed within each area as a percentage of the area's load at each bus;
- DER were modeled as distributed generation (DG) in the load models in the power flow base cases;
- IEEE 1547-2003-based dynamics models were used to represent the capabilities of the DER in transient stability studies; and

[4] An integrated electric power market and system simulation application. This is the software that was used for the production cost model simulations in this assessment.

- Load demand was not adjusted in the PCM.

Limitations of the DER Study

- There was no additional transmission expansion allowed in this study other than what was assumed in the 2030 ADS PCM V2.2.1; and
- No major technology breakthroughs were considered for this study regarding cost or performance. All technology innovation was consistent with existing DER and batteries in the 2030 ADS PCM.

The cases below were selected to represent two increased levels of DER penetration, i.e., 20% and 35% DER penetration.

Table 1: Case Setup per scenario

Scenario	Case Setup
2030 ADS PCM V2.2.1 (ADS PCM V2.2.1)	• Starting and comparison case • 9% of installed generation capacity was DER
20% DER PCM Case (20% DER)	• Started with the 2030 ADS PCM V2.2.1 case • Increased DER capacity to about 20%
35% DER PCM Case (35% DER)	• Started with the 2030 ADS PCM V2.2.1 case • Increased DER capacity to about 35%
35% DER Redistributed PCM Case (35% DER Redistributed)	• Started with the 2030 ADS PCM V2.2.1 case • Increased DER capacity to about 35% • Distributed about half of the California DER capacity to the other states and provinces
35% DER Redistributed PCM Case with 400 MW x 4-hour battery storage (35% DER Redistributed 400MWx4hr)	• Started with the 2030 ADS PCM V2.2.1 case • Increased DER capacity to about 35% • Distributed about half the California DER capacity to the other states and provinces • Updated Path 45 rating from 408 MW to 600 MW north to south from June 1 through November 1 • Added 400 MW x 4-hour battery storage to each area in the case • Made all Comisión Federal de Electricidad (CFE) thermal units “Must Run”

20% DER Power Flow and Dynamics Case (20% DER PF)	• Similar to the 2030 ADS PCM V2.2.1 PCM case • DER capacity was added to the case to represent the same percentage of load served by DER as in hour 5509 (August 18, 1 p.m. MT) in the 2030 ADS PCM V2.2.1 case.

Input Data

This assessment started with the 2030 ADS PCM V2.2.1 as a foundational case for the studies. All cases built in this assessment used this starting case. The DER penetration levels assumed in each case represented aggressive adoptions of DER in the form of BTM rooftop solar.

Batteries were also added to reveal the impacts of battery storage along with high DER penetrations. The battery configurations considered for this study were 400 MW x 4-hour battery, and 200 MW x 8-hour battery. The study showed that the 400 MW x 4-hour battery configuration was superior because it resulted in a larger decrease in thermal energy and a larger increase in battery storage use than the 200 MW x 8-hour battery configuration.

The power flow and dynamics cases were built on the 2030 Heavy Summer 1 base case. This was also the reference case used to develop the 2030 ADS PCM V2.2.1.

PCM Approach

DER in this assessment is modeled as BTM rooftop solar. To scale the DER for this assessment, a per capita DER value was calculated for each state in the 2030 ADS PCM. This calculation showed that California and Arizona have the highest amount of DER capacity per capita—0.54 MW/1,000 people. The 2030 ADS PCM V2.2.1 case had a total of about 28,000 MW of DER capacity.

The next step was to increase the DER in each of the other states and provinces to 0.54 MW/1,000 people per capita capacity. Then California and Arizona DER per capita capacity was increased beyond 0.54 MW/1,000 people until an overall 20% DER capacity was obtained for the entire Western Interconnection. The assumption was that California and Arizona would become even more aggressive after every other state has reached 0.54 MW/1,000 people per capita capacity—adopting another 50% DER capacity (0.81 MW/1,000 people). This added about 32,000 MW of DER capacity compared to the 2030 ADS PCM case, totaling about 60,000 MW of DER capacity in the 20% DER case. Since the state boundaries do not exactly match modeled areas in the PCM, the calculated desired per state per capita value was distributed to areas within each state. This resulted in 20% of generation capacity in the Western Interconnection being DER.

To reach 35% DER capacity, the DER capacity in all states and provinces was first increased to 0.54 MW/1,000 people per capita capacity, then increased by 150% compared to the 2030 ADS PCM case for a DER capacity of (0.81 MW/1,000 people), except for California and Arizona, which was increased by 300% compared to the 2030 ADS PCM case for a DER capacity of (1.62) MW/1,000 people). The 35% DER case increased the DER by about 81,000 MW capacity compared to the 2030 ADS PCM case, totaling about 109,000 MW of DER capacity.

The 35% DER Redistributed case has the same amount of DER as the 35% DER case. However, because most of the DER were situated in California in the 35% DER case, half of the DER from California was redistributed evenly to the other states and provinces. Figures 3 through 5 show the DER capacity and distribution for each case.

States other than California had much lower amounts of DER capacity, and some even had negligible amounts, as shown in Figure 5. Even though Arizona and California had a very similar DER per capita in the study, the population in California is much higher, resulting in more DER capacity in California.

In the 35% DER Redistributed case, batteries were then added evenly to each area. Areas in PCM are very similar to registered Balancing Authority Areas (BAA), with a few exceptions. Batteries were added to the 38 areas in the PCM case. Battery storage additions for each area include 400 MW capacity for four hours; i.e., 1,600 MWh per area for the 38 PCM areas. This totaled 15,200 MW capacity (60,800 MWh energy) of battery storage. The battery distribution is shown in Figure 6.

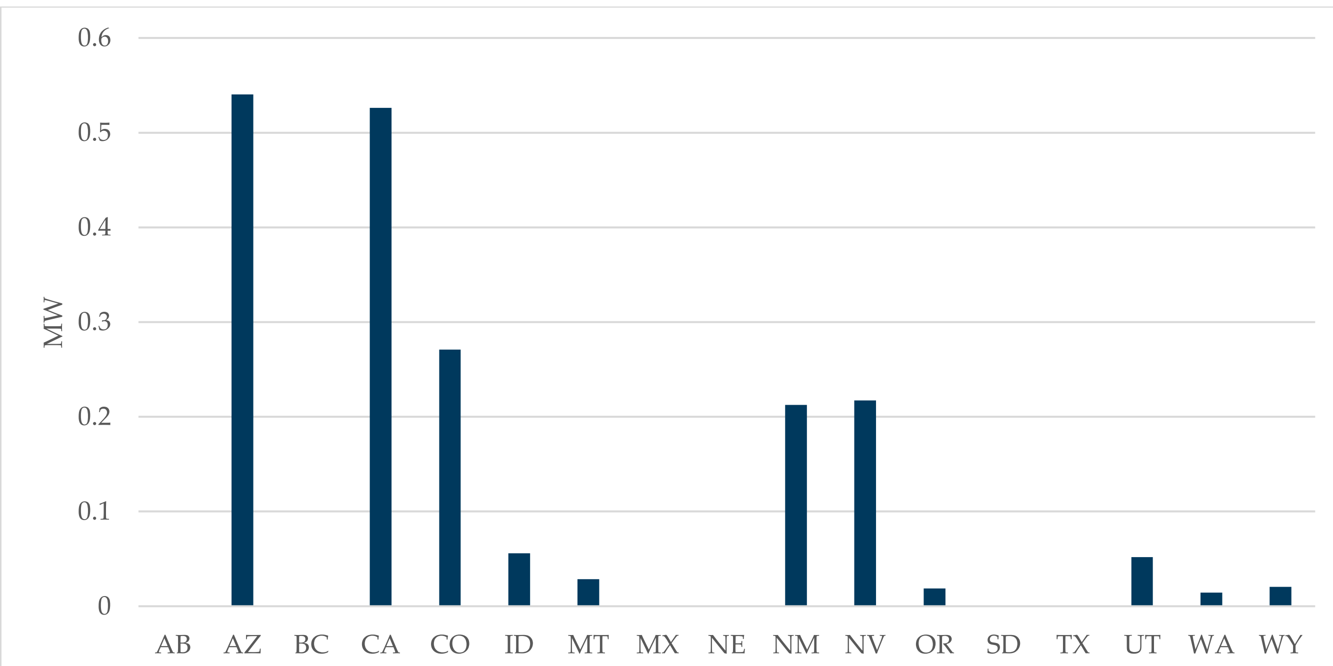

Figure 1: 2030 ADS PCM V2.2.1 installed DER capacity per 1,000 people

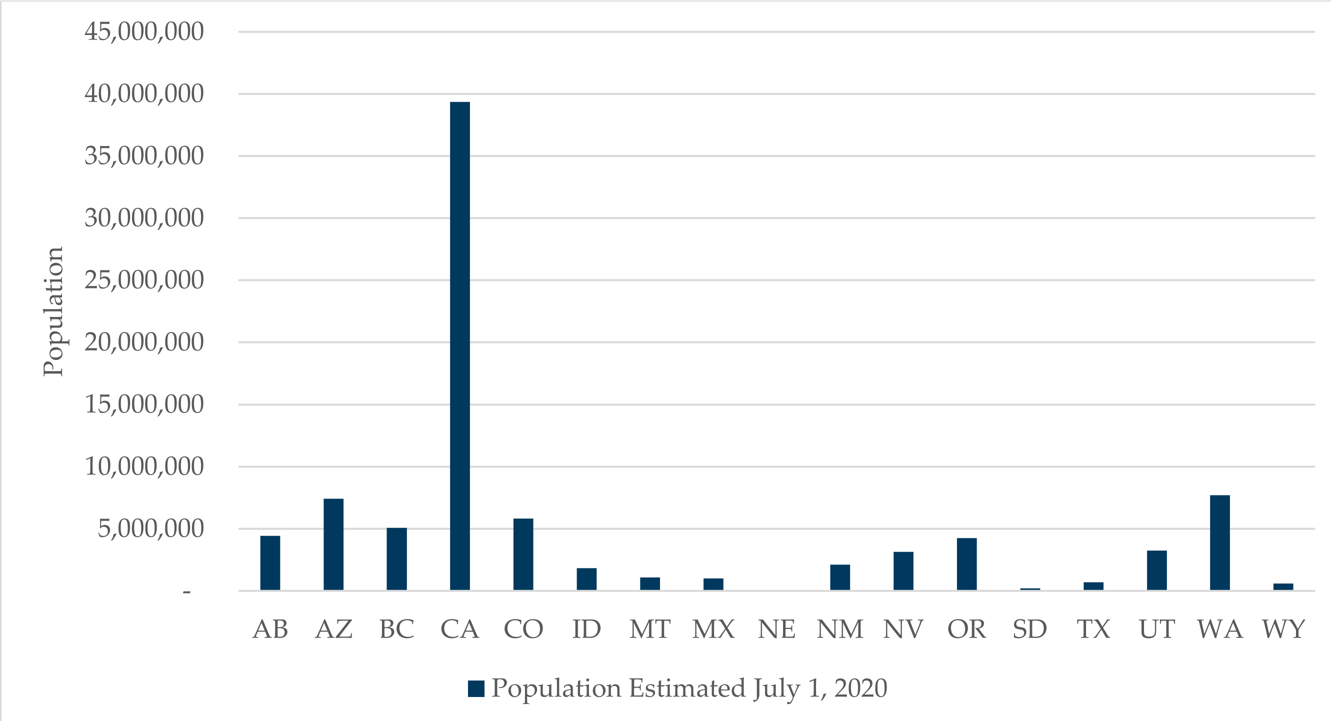

Figure 2: Estimated population by state or area

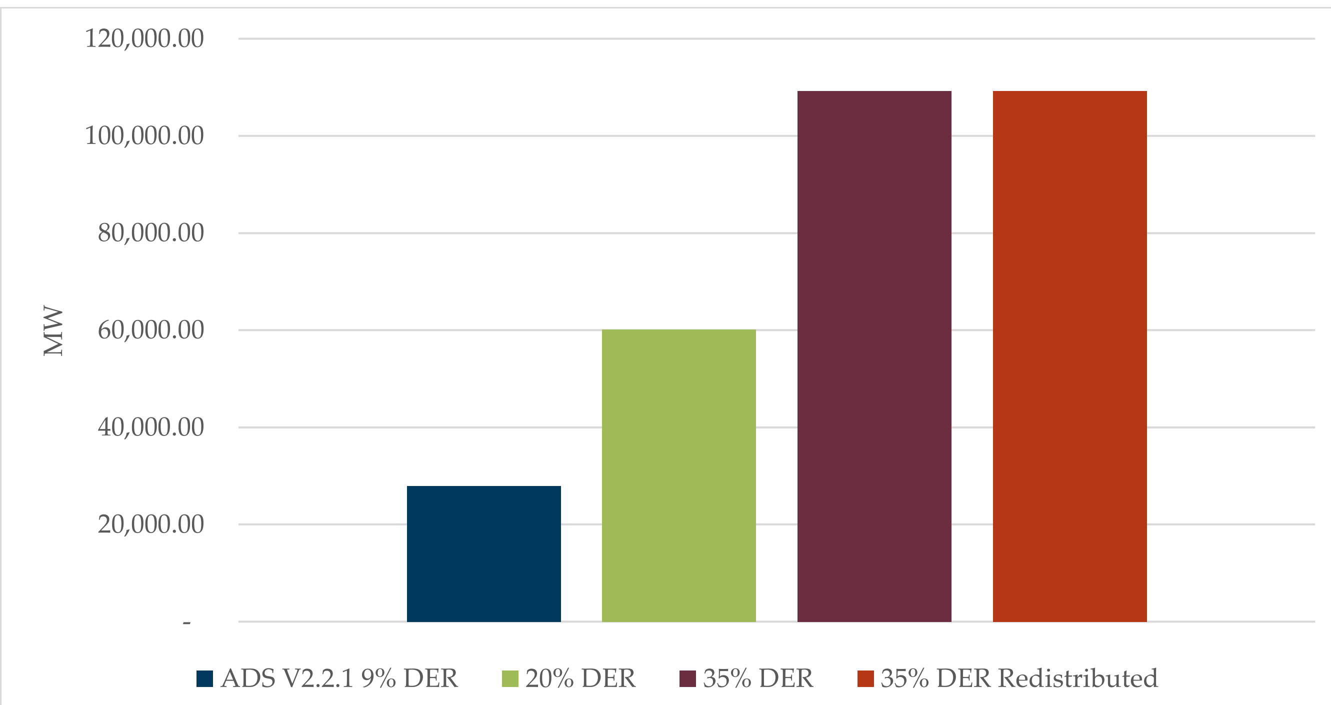

Figure 3: DER capacity by case

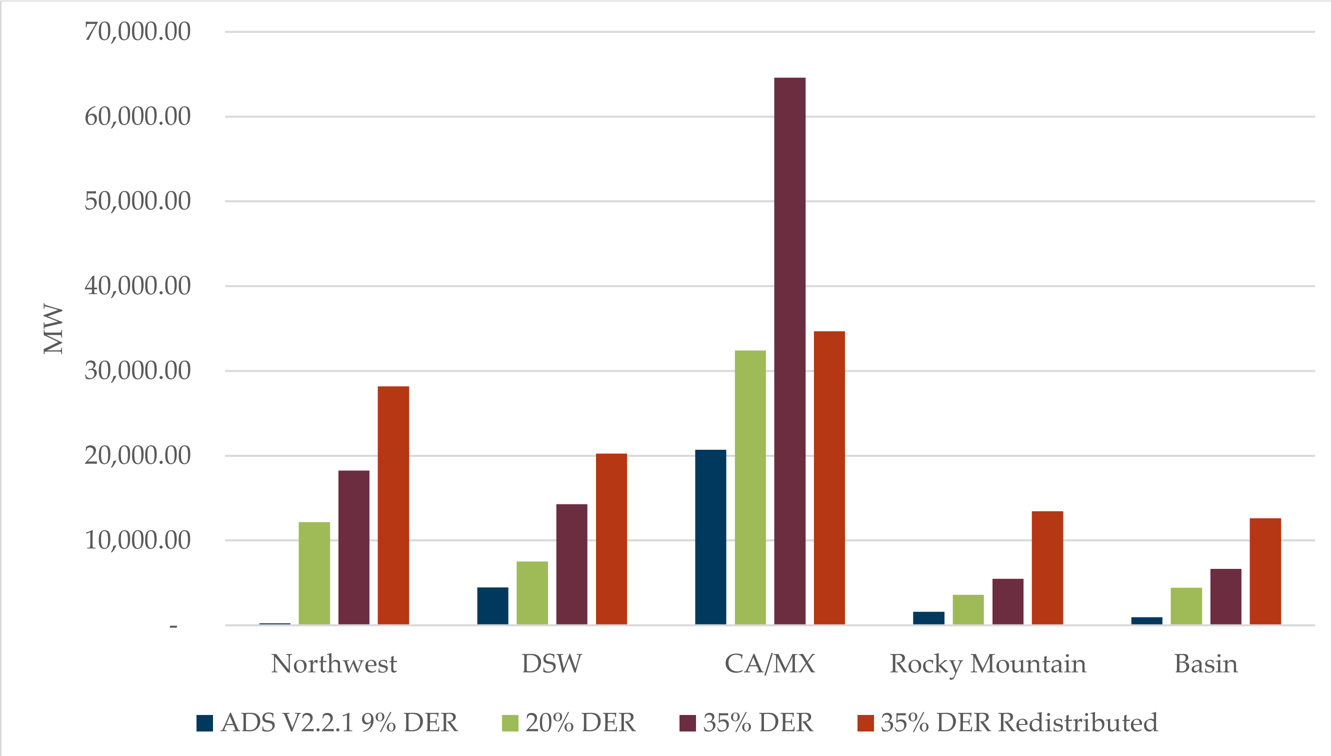

Figure 4: DER Capacity by region

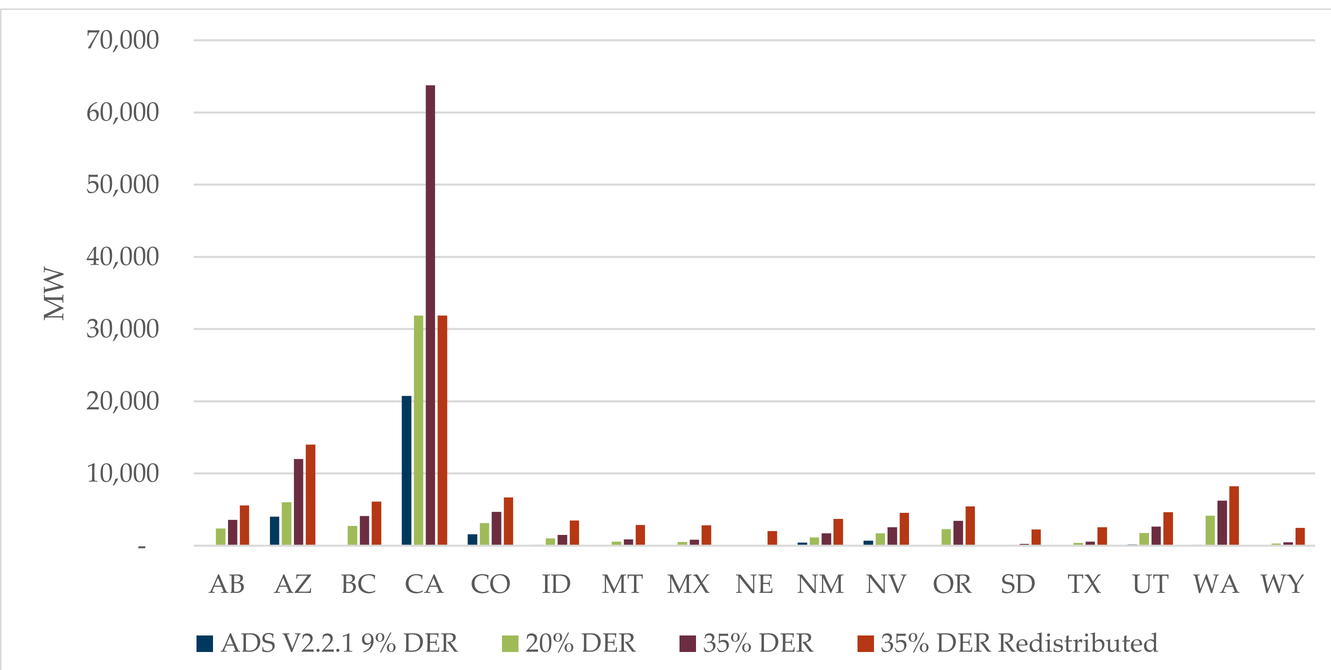

Figure 5: DER capacity by state or province

Below are the DER installed capacities in megawatts per case:

- 2030 ADS PCM V2.2.1—≈28,000 MW DER capacity

- 20% DER—≈60,000 MW DER capacity
- 35% DER—≈109,000 MW DER capacity
- 35% DER Redistributed—≈109,000 MW DER capacity

Increased amounts of DER were correlated with increases of curtailments to utility-scale wind and solar. Therefore, a case with additional batteries was later added to demonstrate the effects of energy storage on the system in conjunction with the high penetrations of DER.

Figure 6 compares the battery capacity by state and province in the 2030 ADS PCM V2.2.1 and the 35% DER Redistributed 400MWx4hr case.

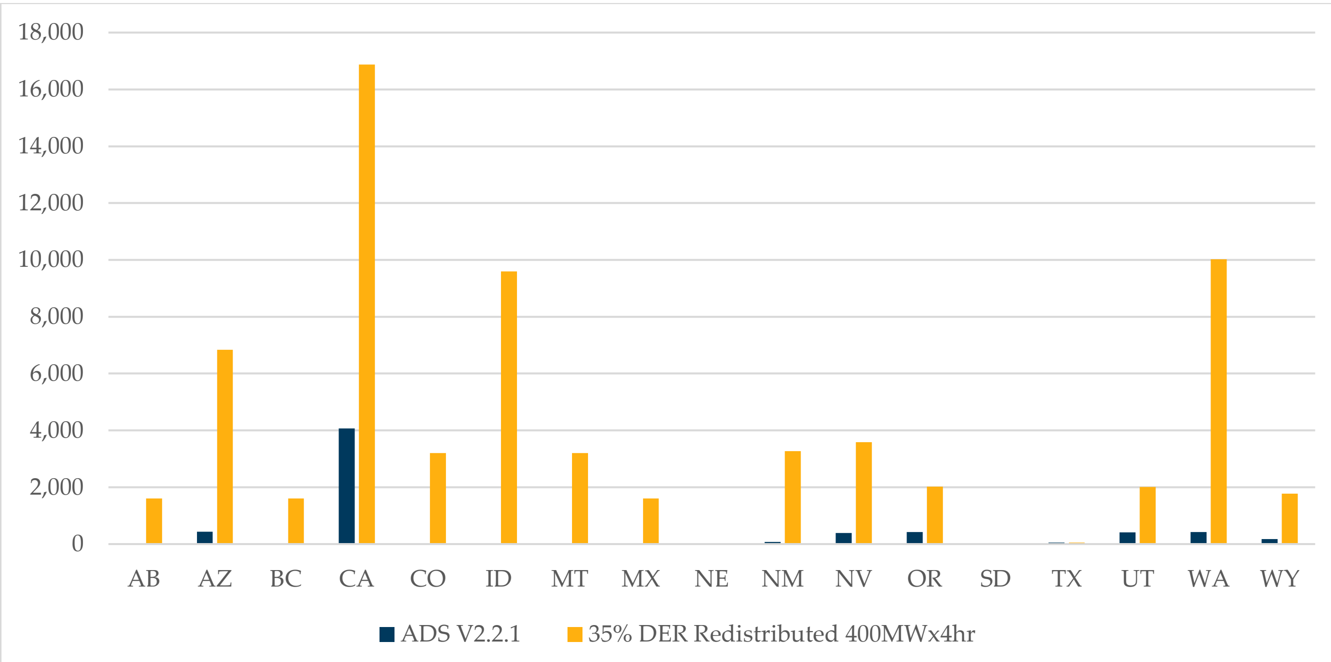

Figure 6: Battery capacity by state and province

Power Flow Approach

Two power flow cases were used in this study.

1. The first case was the original 2030 HS1a1 power flow case. This case was the reference case used as the basis for the 2030 ADS PCM V2.2.1.
2. The second case was a modified version of the 2030 HS1a1. The DER data from August 18th 2030 1:00 p.m. MT in the 2030 ADS PCM V2.2.1 case was used to calculate the proportion of load served by DER on an area by area basis. These proportions were then applied to the original 2030 HS1a1 power flow case to create similar conditions in this new power flow case to the selected hour from PCM. Other generation (thermal, wind, solar, and hydro) was adjusted in the power flow to compensate for the additional DER. The PCM dispatch of the other generation was used as a guide for this dispatch modification. The original 2030 HS1a1 power

flow had approximately 3,524 MW of DER, with 190,294 MW of load. This gave 1.9% of load served by DER. The modified case had approximately 39,718 MW of DER with the same amount of load as the 2030 HS1a1 case. This gave 20% of load served by DER in the case representing the selected hour from PCM.

Initially, dynamics datasets were based on the dynamics models currently used in WECC base cases which are based on California Rule 21 requirements. California Rule 21 is a tariff created by the California Public Utilities Commission "that describes interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system."[5] Use of these models resulted in abnormal DER oscillations as described in the section "Findings and Conclusions—Dynamics." Therefore, it was determined that it would be better to use IEEE 1547-2003[6] compliant models, which did not show oscillations during simulation. Subsequently, three different variations of the dynamics datasets were developed for DER to represent diversity of DER capability. The first dynamic dataset used was the IEEE 1547-2003 model, as parameterized in the NERC DER_A parameterization guideline[7] and used in simulations of both the original 2030 HS1a1 and the 20% DER PF case. The other two variations of the dynamics models were developed to explore potential differences in inverter technology. The second model was intended to represent more advanced panels capable of returning to service quickly after a severe voltage dip. This was done by setting the parameter (Vrfrac) to 1 in the model that controls the fraction of panels that return to service after a voltage dip. The third model used active voltage controls that respond to voltage deviations in the system. These active voltage controls could be included in smart inverters in the future. Most inverters in service do not have this capability. Simulations of the standard disturbances, which are listed in Appendix B—Standard Disturbances, to analyze the effects of increased DER penetration to the Western Interconnection dynamic system response were done with the DER models as described above.

Findings and Conclusions

Annual Energy

Figure 7 shows annual energy supplied by DER as a percentage of total annual energy for each case. In each of the studied cases, the DER capacity is significantly higher than the DER total annual energy due to DER only generating power during the daylight hours. DER annual energy increased from 6% in the 2030 ADS PCM V2.2.1 to 11% for the 20% DER capacity case, whereas 20% annual energy came from

[5] https://www.cpuc.ca.gov/Rule21/

[6] IEEE 1547-2003 standard: https://standards.ieee.org/standard/1547-2003.html

[7] NERC DER_A Parametrization guideline: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

DER for the 35% DER capacity case. In the 35% DER Redistributed case, as some of the DER were redistributed out of California into areas with lower capacity factors for DER as compared to California, annual energy from DER decreased from 20% to 18%. For example, capacity factors for DER in Southern California are higher than the Pacific Northwest.

There was also a slight decrease in annual energy from DER in the 35% DER Redistributed 400MWx4hr case compared to the 35% DER Redistributed case from 18% to 17% because battery storage was also able to contribute to the annual energy.

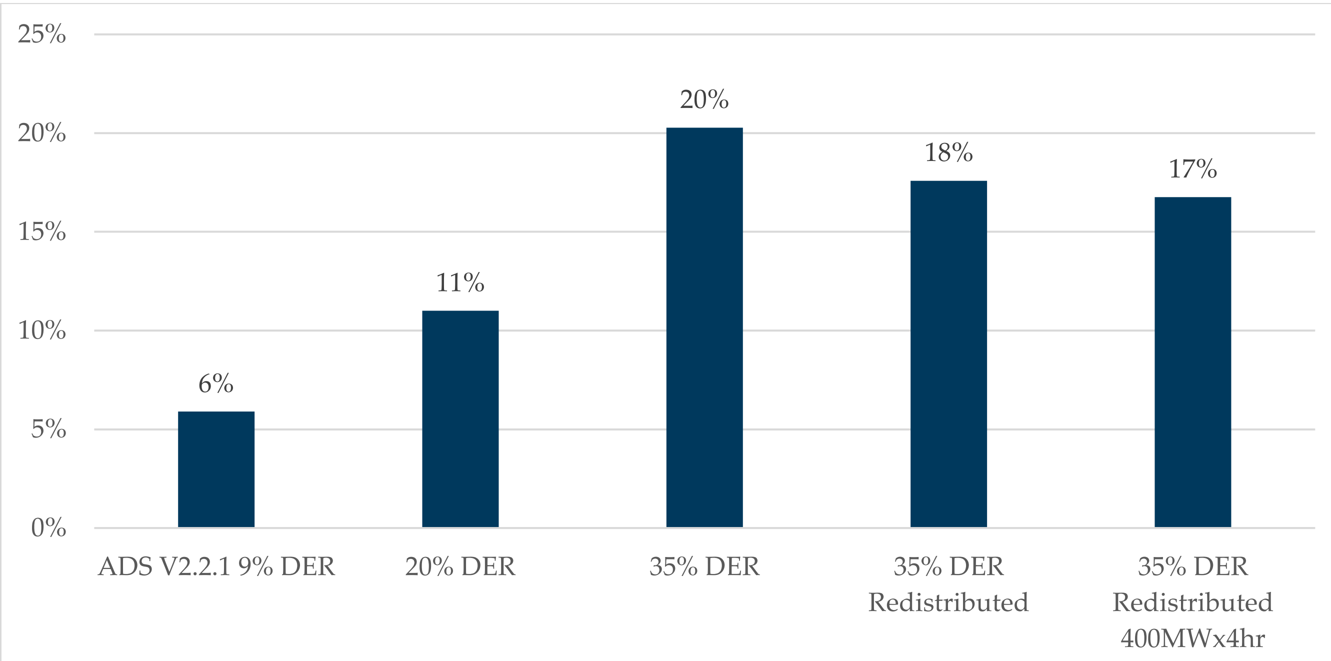

Figure 7: Percentage of annual energy from DER (DER/Total Generation)

There are some annual energy trends that emerge from each simulation. Figure 8 shows the annual energy by technology type for each of the studied cases. Nuclear energy output stayed nearly the same in all simulations because nuclear units are baseload units. Hydro units either followed hourly shapes or were modeled as load-following based on the individual characteristics of each hydro plant. The simulations resulted in increased load being served by DER (depending on capacity in each case) since it was a must-take resource. Due to this, thermal units saw reduced annual energy. For example, the 20% DER case shows a decrease in coal, combined-cycle gas, and combustion turbine generation and an increase in DER generation compared to the 2030 ADS PCM. There was also a decrease in utility-scale solar and wind output as DER capacity increased, but when some of the DER were redistributed to regions outside of California, the capacity factor for DER decreased, resulting in increased wind and solar generation.

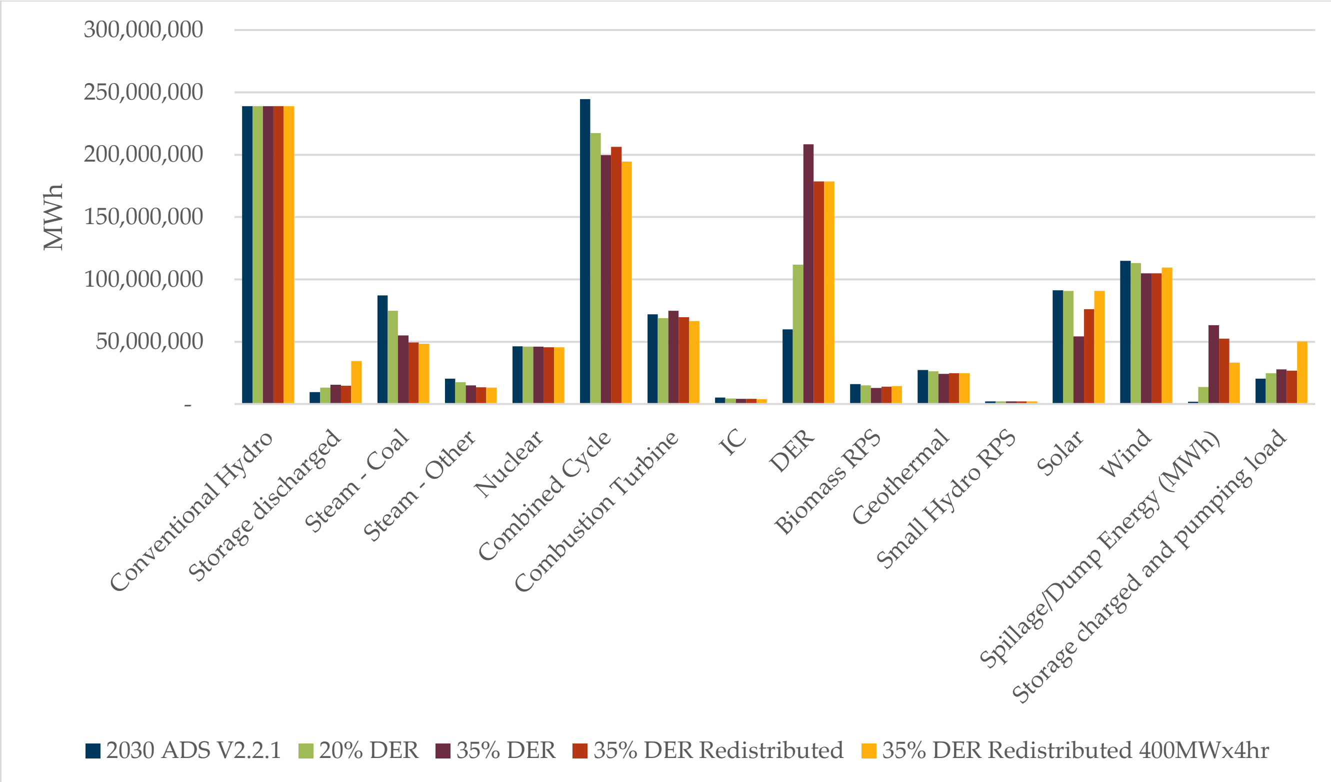

Figure 8: Annual energy (MWh)

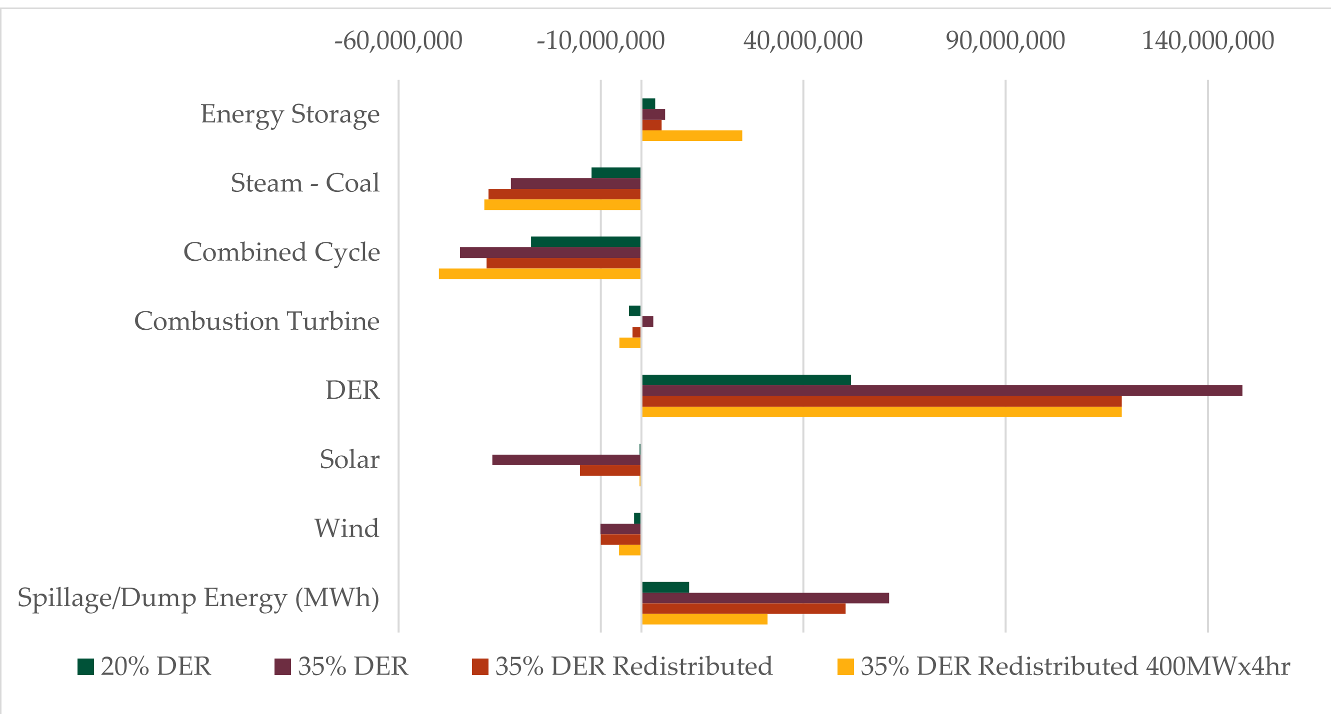

Figure 9: Largest Annual Energy Change From 2030 ADS PCM V2.2.1 vs. All Other Study Cases (MWh)

Annual Energy Change Per State or Province From 2030 ADS PCM V2.2.1

The following set of figures show the change in annual energy per state or province from the 2030 ADS PCM V2.2.1 case in each of the studied cases. Figure 10 represents annual energy change from the 2030 ADS PCM V2.2.1 to the 20% DER cases. The chart shows an increase in DER in many of the states, most of it in California. There was an overall decrease in thermal generation. Many areas saw increased curtailment of utility-scale solar and wind due to higher penetrations of DER.

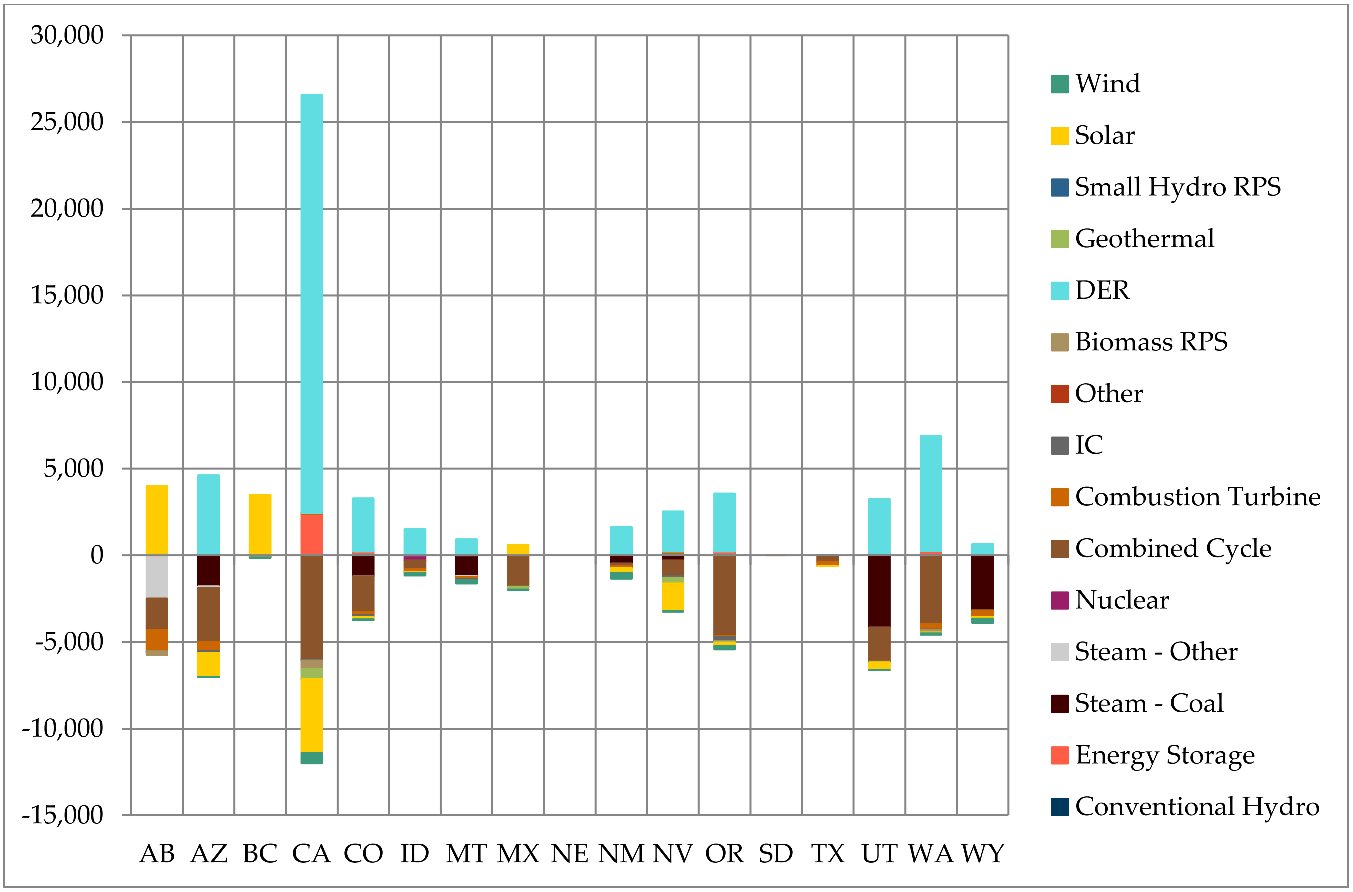

Figure 10: Annual generation change (GWh)—2030 ADS PCM V2.2.1 vs. 20% DER

Figure 11 shows more energy production from DER, bigger decreases in coal energy and combined-cycle gas, with more curtailment of utility-scale wind and solar. Although energy from combined-cycle gas has decreased, there is an increase in combustion turbine gas. This is due to their fast-ramping characteristics required by the system when solar DER production drops off at the end of the day, and combustion turbine gas generation provides the necessary generation ramping capability to meet demand. Most of the increase in combustion turbine gas generation was in California. The second largest increase was seen in Colorado.

Figure 11 shows the annual energy differences between the 2030 ADS PCM V2.2.1 and 35% DER cases.

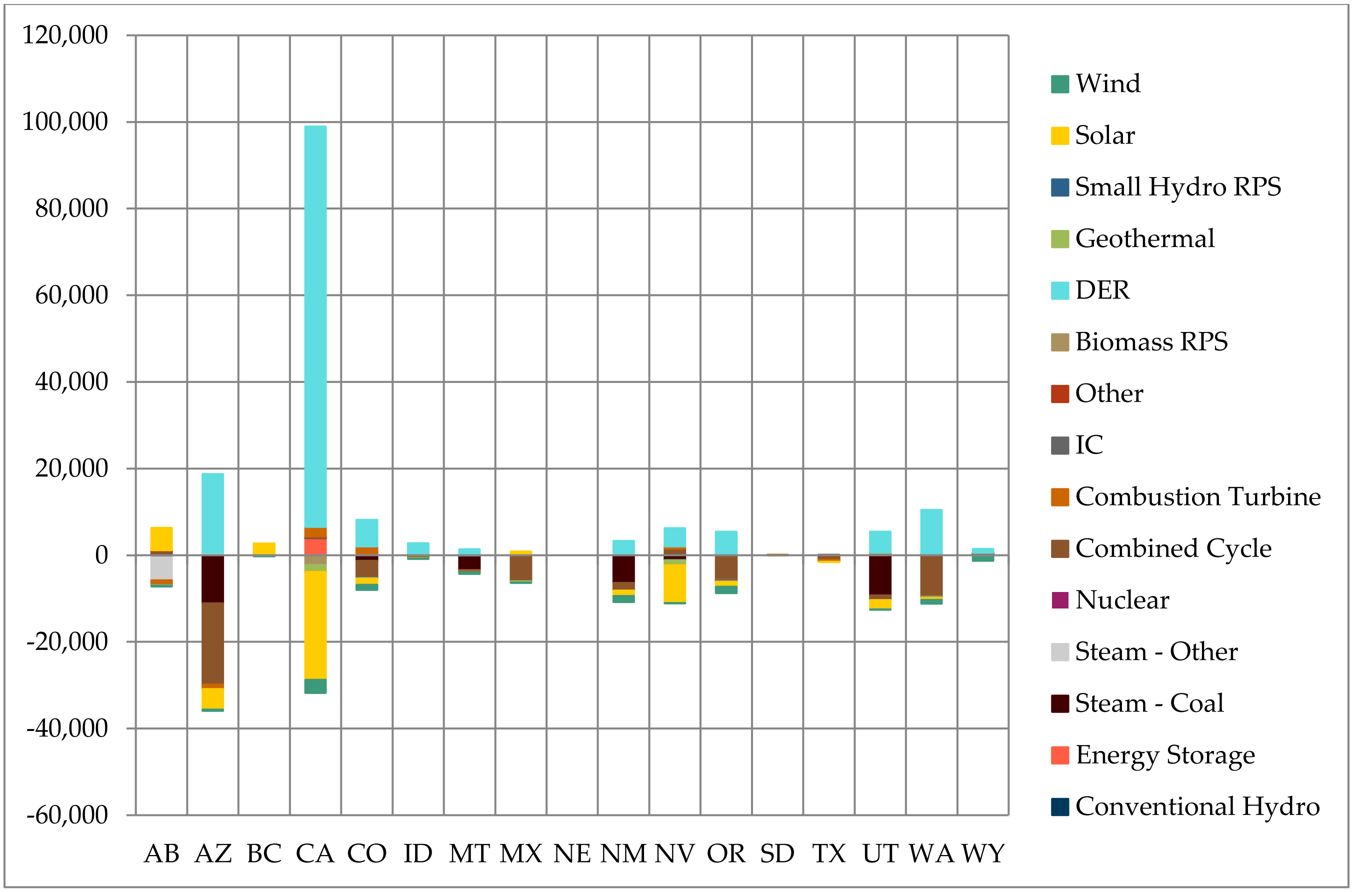

Figure 11: Annual generation change (GWh)—2030 ADS PCM V2.2.1 vs. 35% DER

The 35% DER Redistributed case is very similar to the 35% DER case as shown in Figure 12. However, energy from DER decreased because some of the California DER had been redistributed to other areas with less solar output than what California would have had. This resulted in less energy from DER compared to the 35% DER case. Figure 12 shows less annual energy from DER in the 35% DER Redistributed case than in the 35% DER case. Additionally, there is less curtailment of utility-scale wind and solar for the 35% DER Redistributed case.

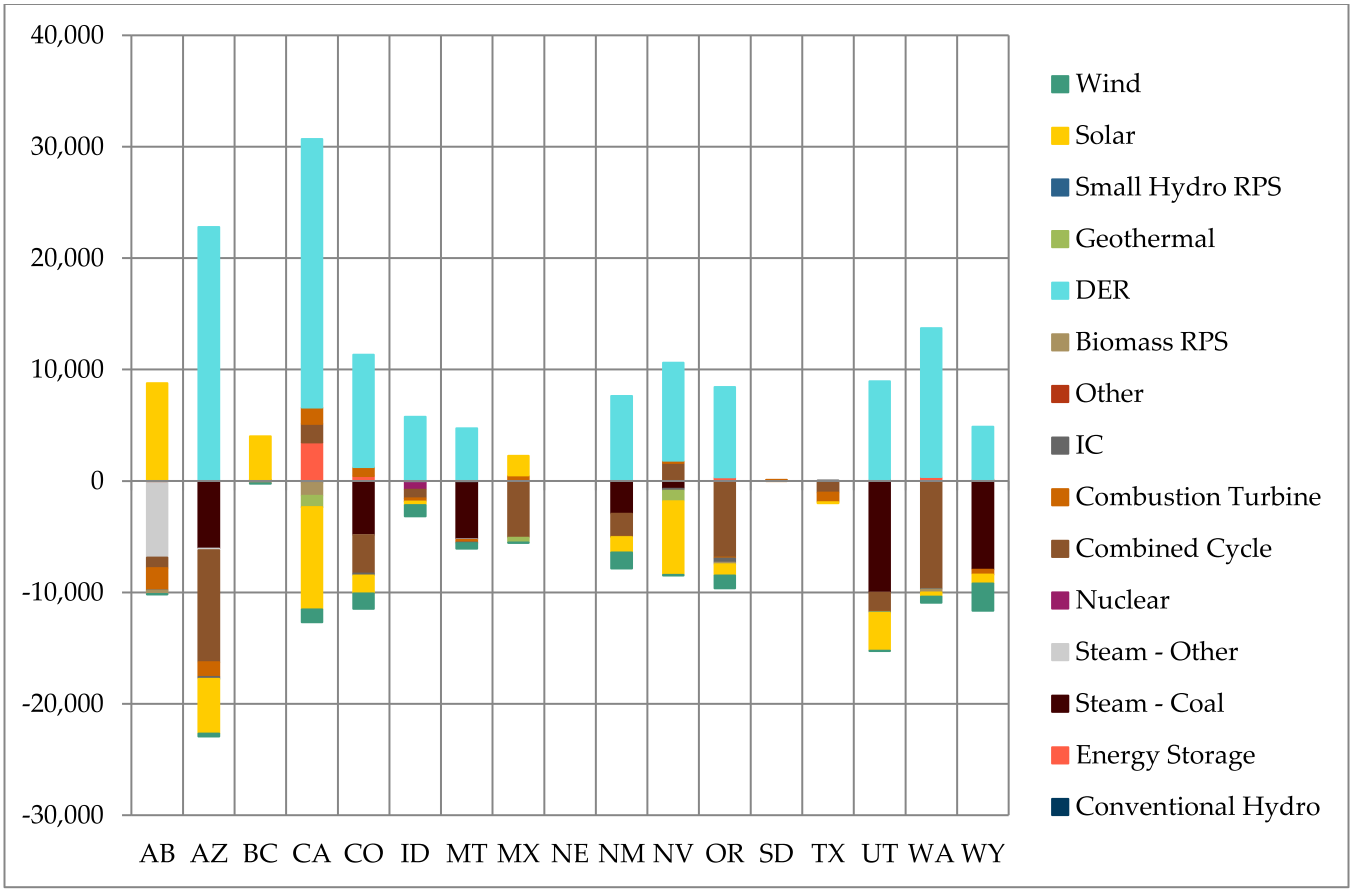

Figure 12: Annual generation change (GWh)—2030 ADS PCM V2.2.1 vs. 35% DER Redistributed

Energy storage was added to the study by representation of grid-level batteries in the form of 400 MW x 4-hour battery storage for each of the areas in the PCM totaling 15,200 MW capacity (60,800 MWh energy) battery storage.

In the 35% DER Redistributed 400MWx4hr case, in each area, there is extra energy throughout the day from renewables (solar and wind) to be stored in batteries and dispatched later. Figure 13 shows that this case does not curtail nearly as much utility-scale solar and wind as the other cases due to the requirement to charge batteries. This case had the least amount of annual energy from thermal units. This was due to the combination of 35% DER capacity combined with additional battery storage, which helped serve the evening load.

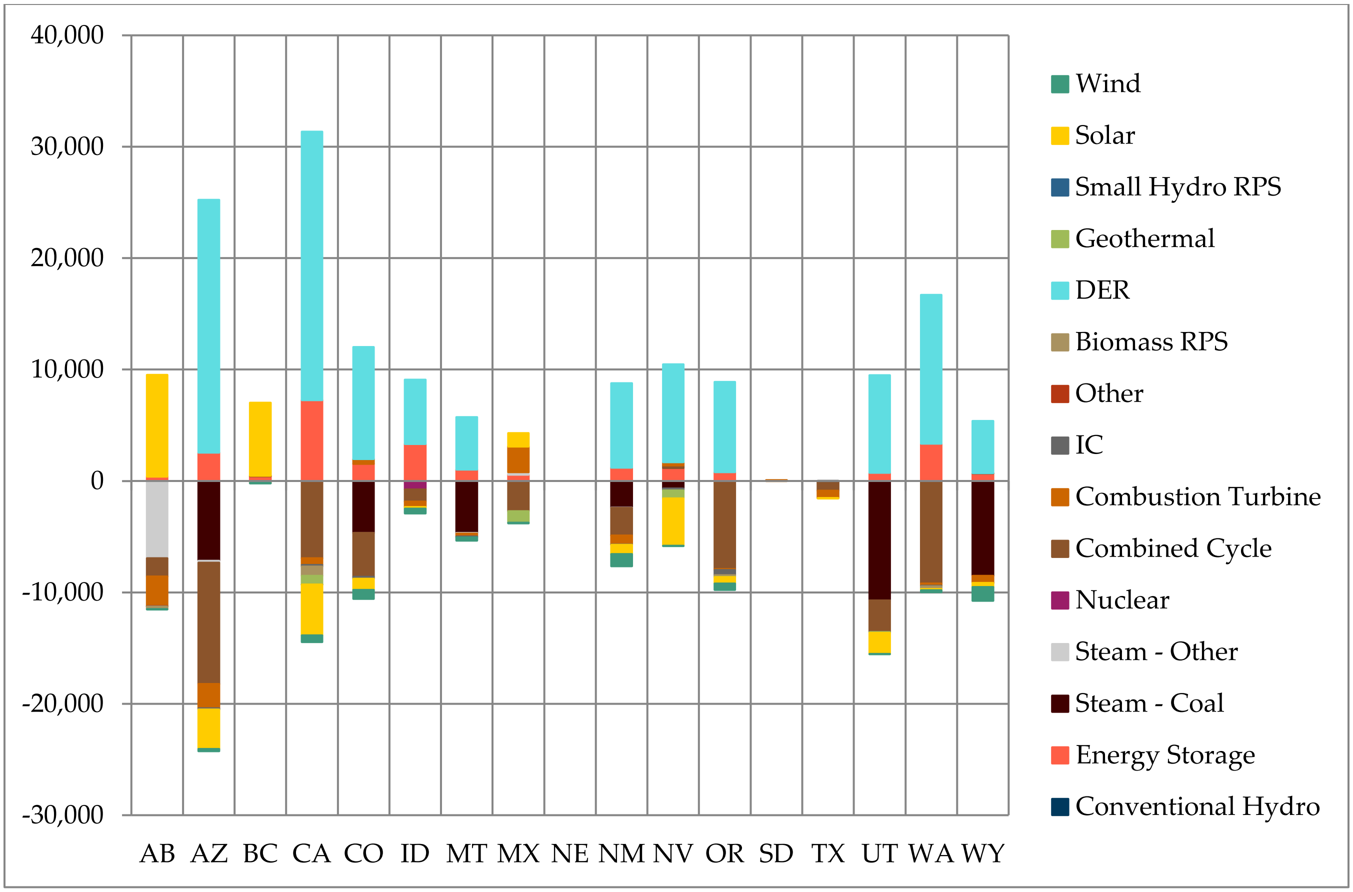

Figure 13: Annual generation change (GWH)—2030 ADS PCM V2.2.1 vs. 35% DER Redistributed 400MWx4hr

In each of the cases above, the high levels of DER resulted in a decrease in thermal generation output and an increase in utility-scale solar and wind curtailment during the day, since the DER could not be curtailed. Some thermal units remained on due to system requirements for ramping, Must Run assignments, and unit commitment requirements. For example, if a generating unit was needed in the morning, but not needed in the middle of the day, and needed again during the afternoon ramp it may not have enough time to turn off and on again due to the minimum down time constraints. If the generator minimum down time is longer than the time the unit would be turned off, then the generator would stay online and not turn off. This is an example of a unit commitment requirement forcing a generating unit to stay on even when it is not needed.

Figure 14 shows energy curtailment for each case. Curtailment is the energy generated by utility-scale wind and solar resources but is in excess of the demand. The cases with the most DER resulted in the most curtailment of utility-scale wind and solar generation. As DER were redistributed to areas outside of California due to decreased annual energy from DER, the solar and wind resources saw less curtailment. Furthermore, as batteries were added, that extra energy was stored rather than curtailed. Battery additions also showed a noticeable decrease in fast ramping natural gas resources (combustion turbine and combined cycle) since the batteries were able to contribute to the evening ramp as the sun goes down.

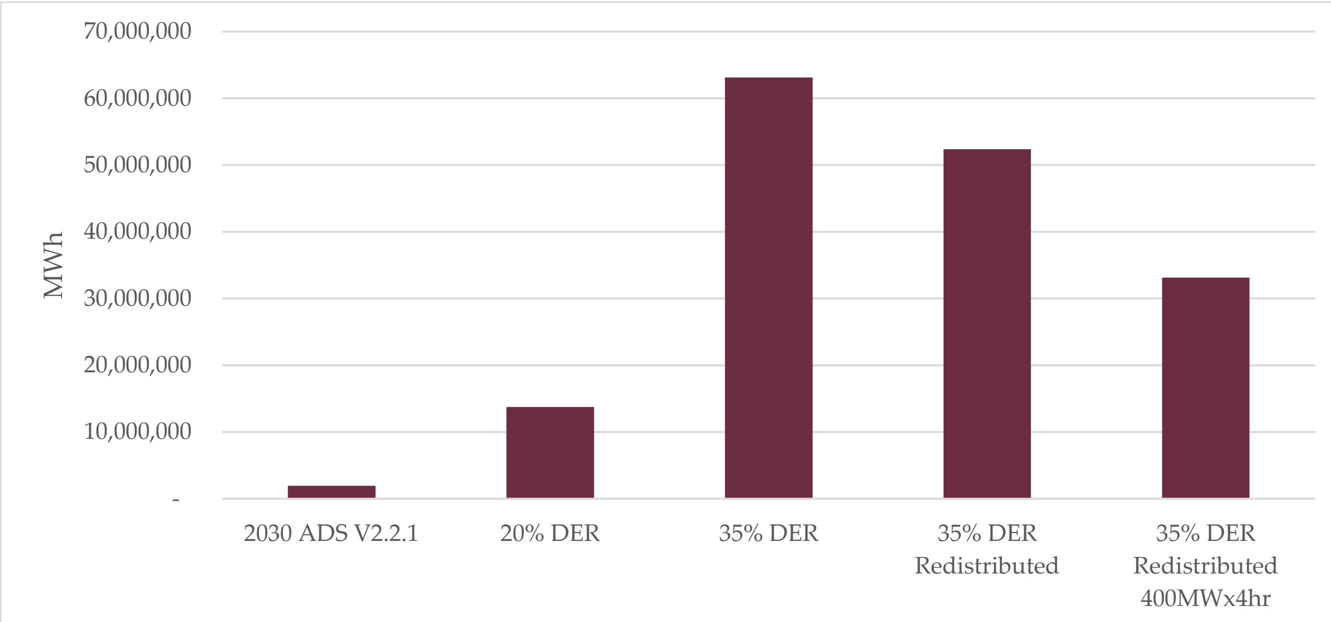

Figure 14: Annual energy curtailment

Coal Units Offset

DER penetrations also played a role in how coal units were dispatched in the simulations. Overall, coal units were dispatched less and remained offline more compared to the 2030 ADS PCM V2.2.1. Figure 15 shows the monthly percentage of hours that the coal units were dispatched.

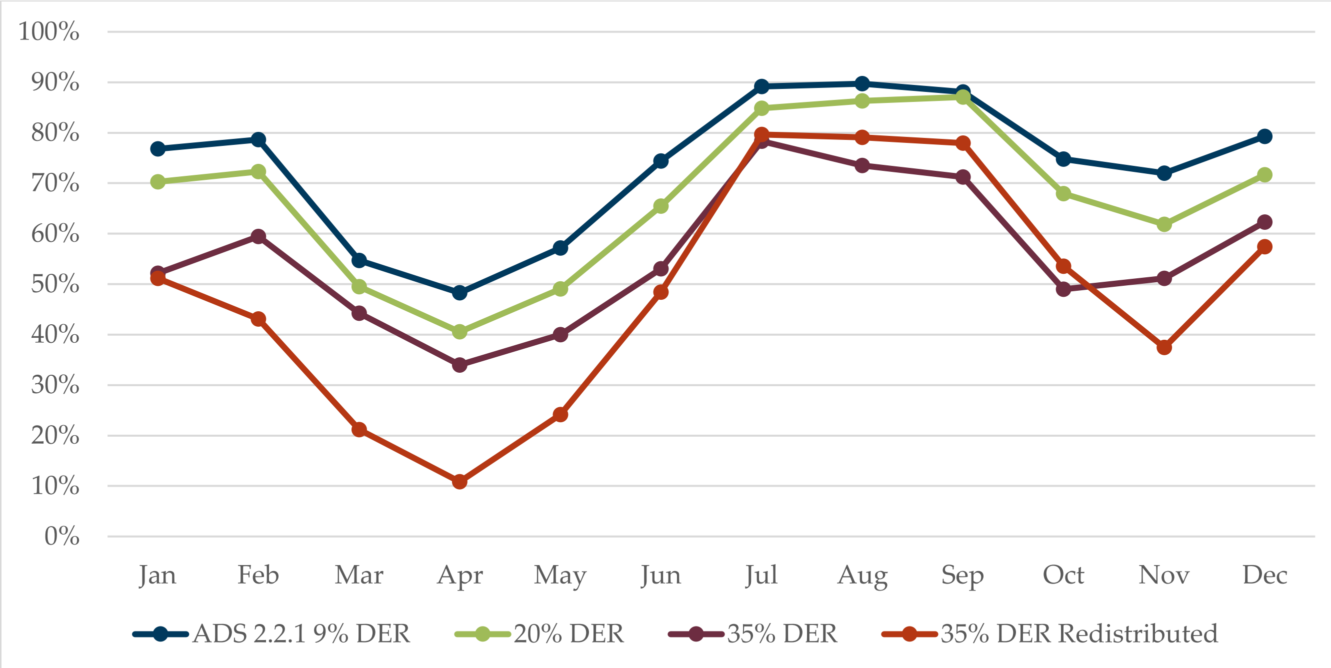

Figure 15: Percentage of hours coal units are dispatched

Figure 16 represents the total combined hours that the coal units remained offline in each area. The biggest reduction in coal unit dispatch occurred in Colorado, Utah, and Wyoming, mainly in the following areas: Western Area Power Administration Colorado-Missouri region (WACM), PacifiCorp Utah (PAUT), and PacifiCorp Wyoming (PAWY).

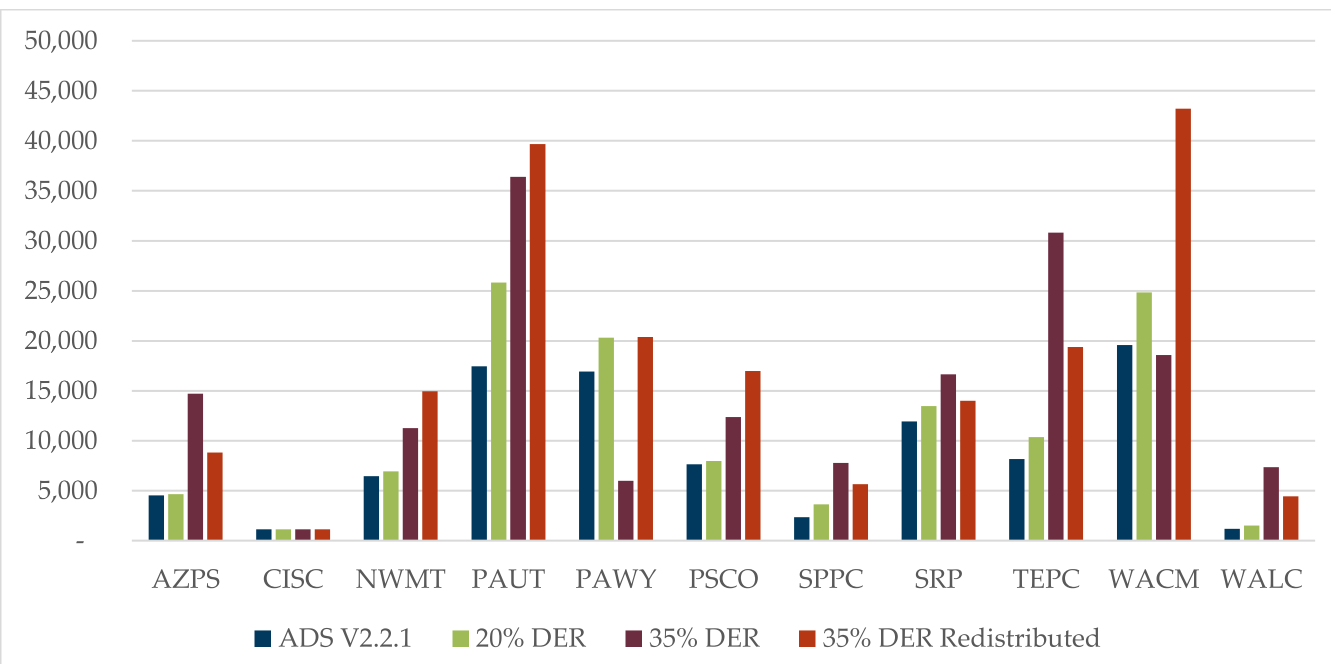

Figure 16: Sum of zero output (offline) hours of coal units by area

Average Summer Day Dispatch

Figure 17 and Figure 18 show average summer day curtailment of wind and solar generation at different DER levels. Figure 17 shows more wind curtailment in the 35% DER Redistributed case compared to the 35% DER because, as the DER were redistributed out of California, some of these areas typically generated more wind than California. Since the DER are modeled as a must-take resource and not allowed to curtail, the areas with more wind were forced to curtail.

Figure 18 shows more solar curtailment in the 35% DER case than in the 35% DER Redistributed case. This is because California tends to have higher solar output than many other areas in the Western Interconnection. So, when some of the DER were distributed outside of California as a must-take resource, there was less solar output overall, resulting in less solar to be curtailed.

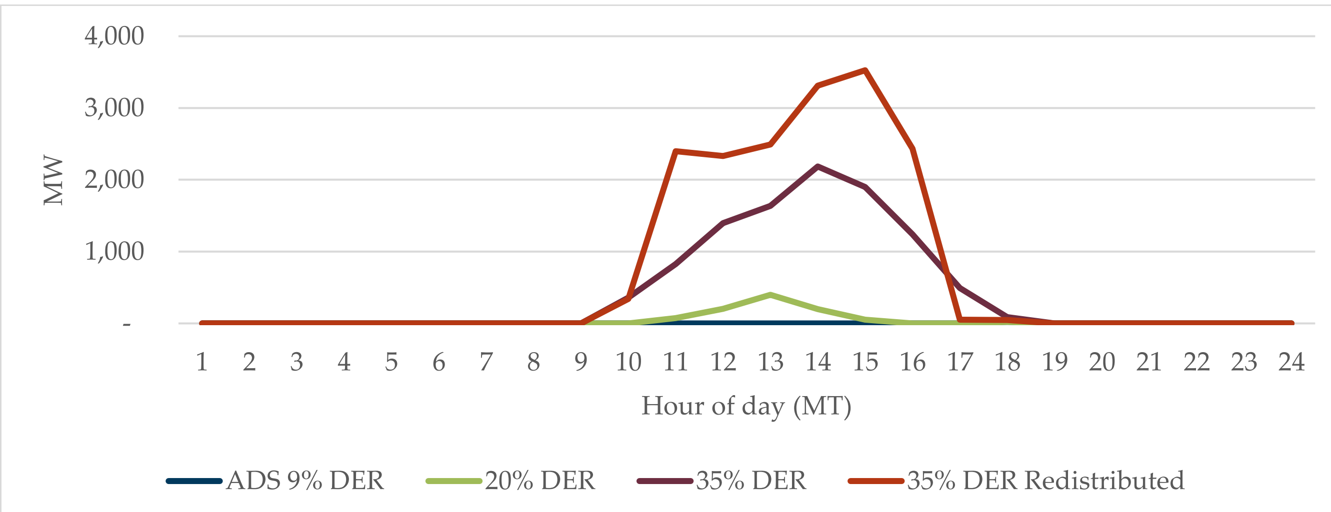

Figure 17: Wind curtailment for August 18, 2030

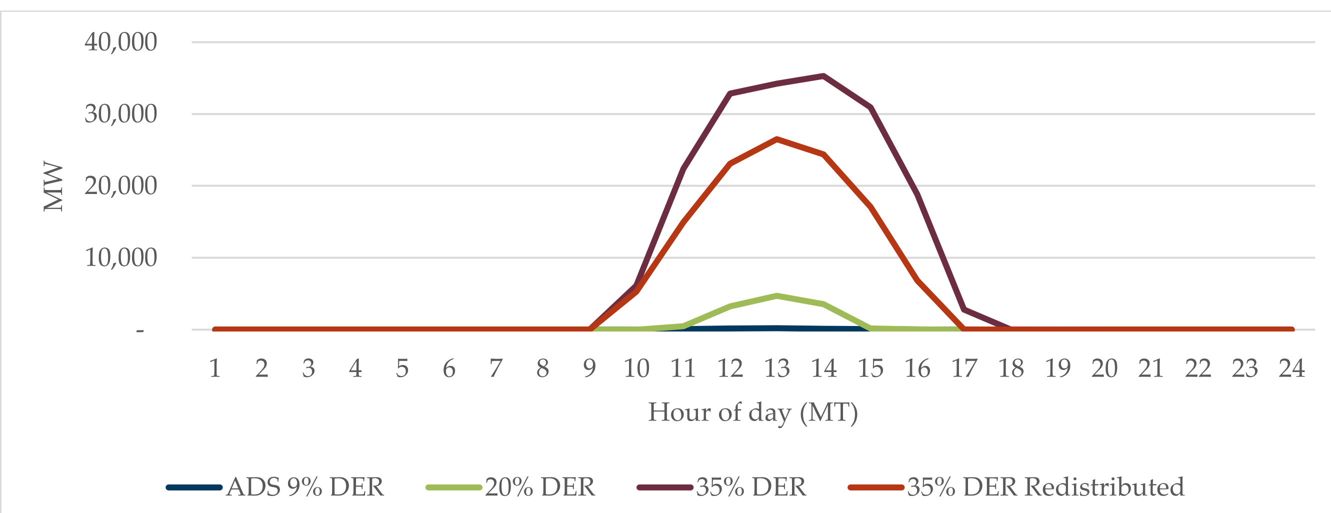

Figure 18: Solar curtailment for August 18, 2030

Figure 19 shows the same hour (August 18, 2030, 1:00 p.m. MT) generation dispatch in megawatts for each unit type for each case. This figure shows that the DER tends to dominate the resource mix during this hour, curtailing more solar/wind with increased DER penetrations. Also, adding batteries to the case (35% DER Redistributed 400MWx4hr) allows for less solar/wind curtailment as solar/wind energy is used to charge the batteries.

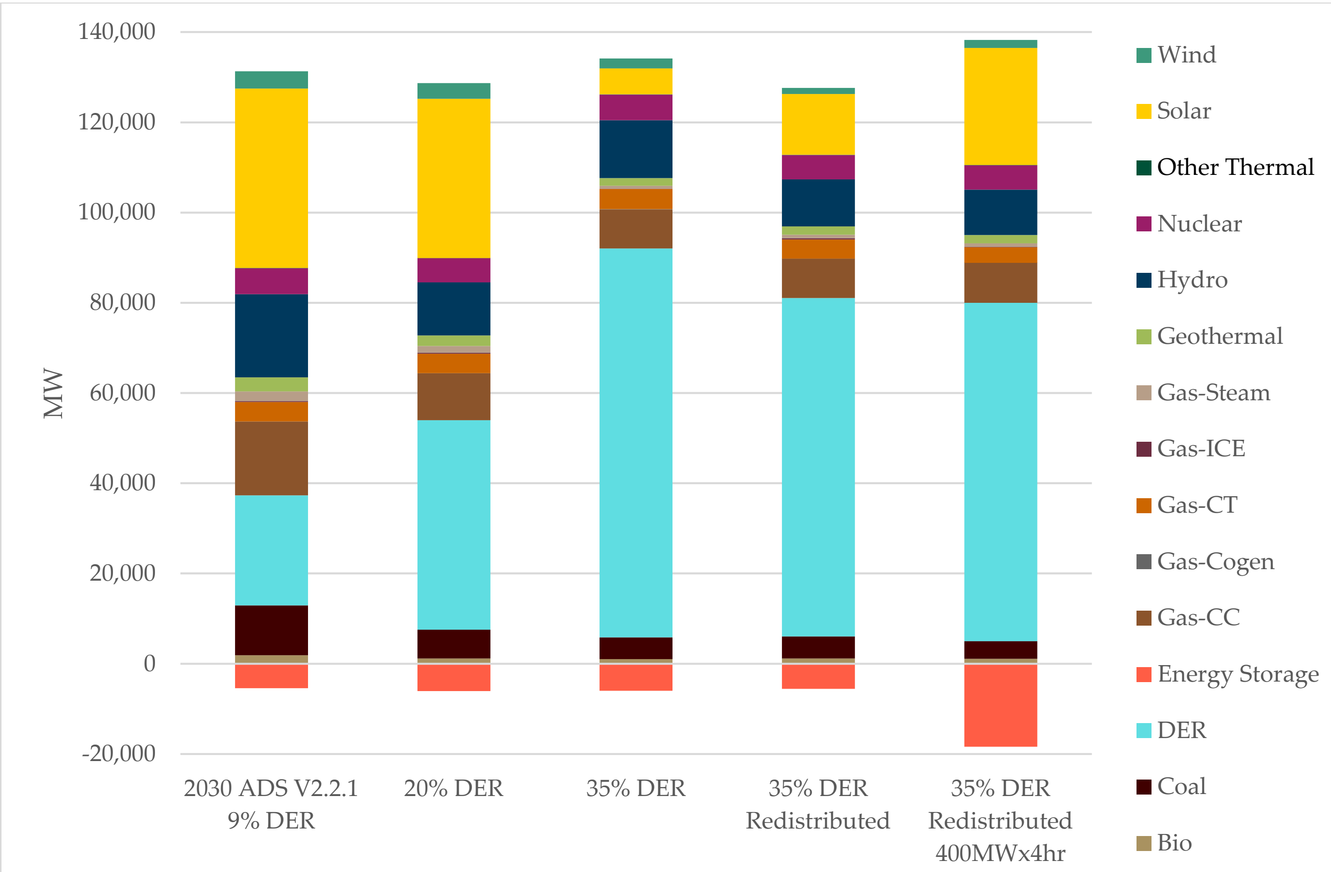

Figure 19: Generation Dispatch, August 18, 2030, hour 13

Figure 20 shows the DER energy as a percentage of total energy on August 18, 2030, 1:00 p.m. MT and August 18, 2030, 8:00 p.m. MT. The percentage of energy from DER is much higher than the yearly average (shown in Figure 7) during the day—around 1:00 p.m. MT—and much lower than the yearly average in the evening—around 8:00 p.m. MT.

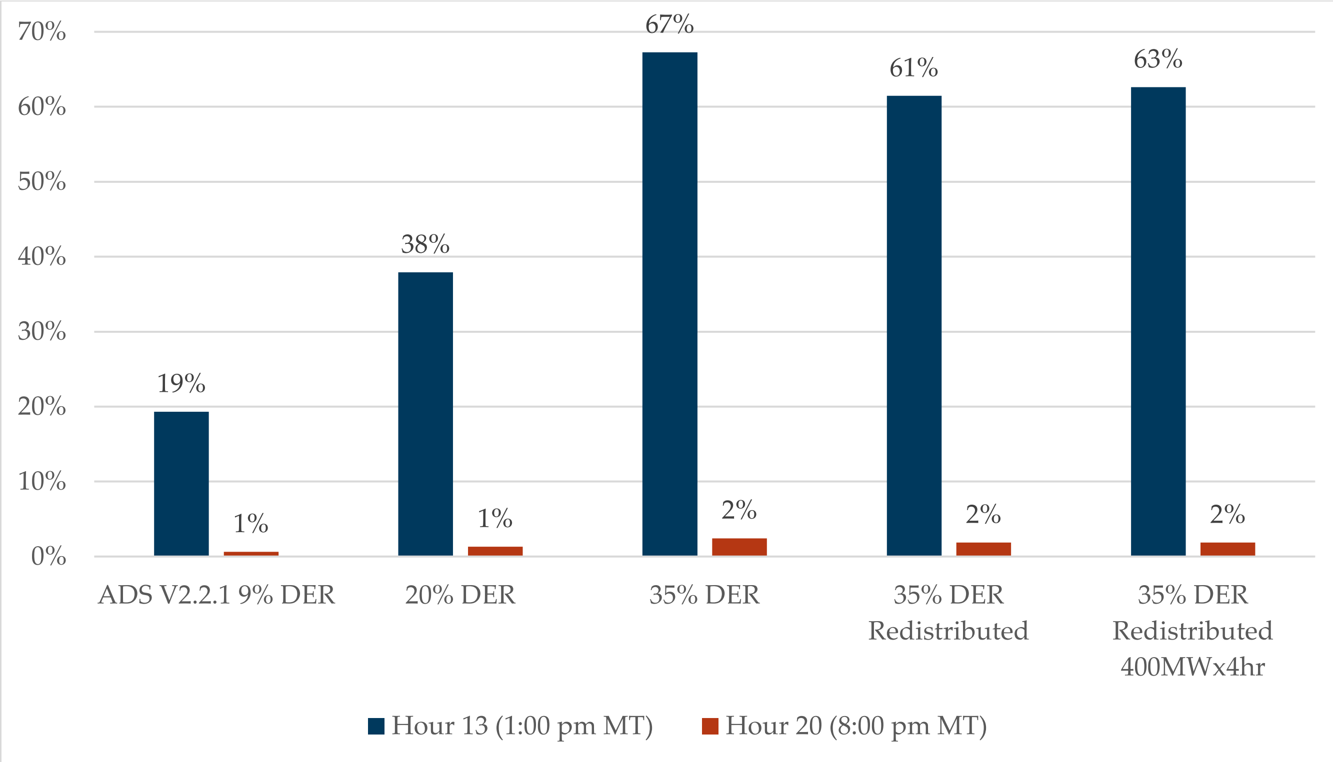

Figure 20: August 18 DER Energy/Total Energy; (1:00 p.m. and 8:00 p.m. MT)

In the case with battery storage (35% DER Redistributed 400MWx4hr), the batteries that were charged during the day by renewables were able to discharge and serve the load demand in the evening. As can be seen in Figure 21 for Hour 20 (8:00 p.m.), in the 35% DER Redistributed 400MWx4hr bar graph, batteries offset thermal generation.

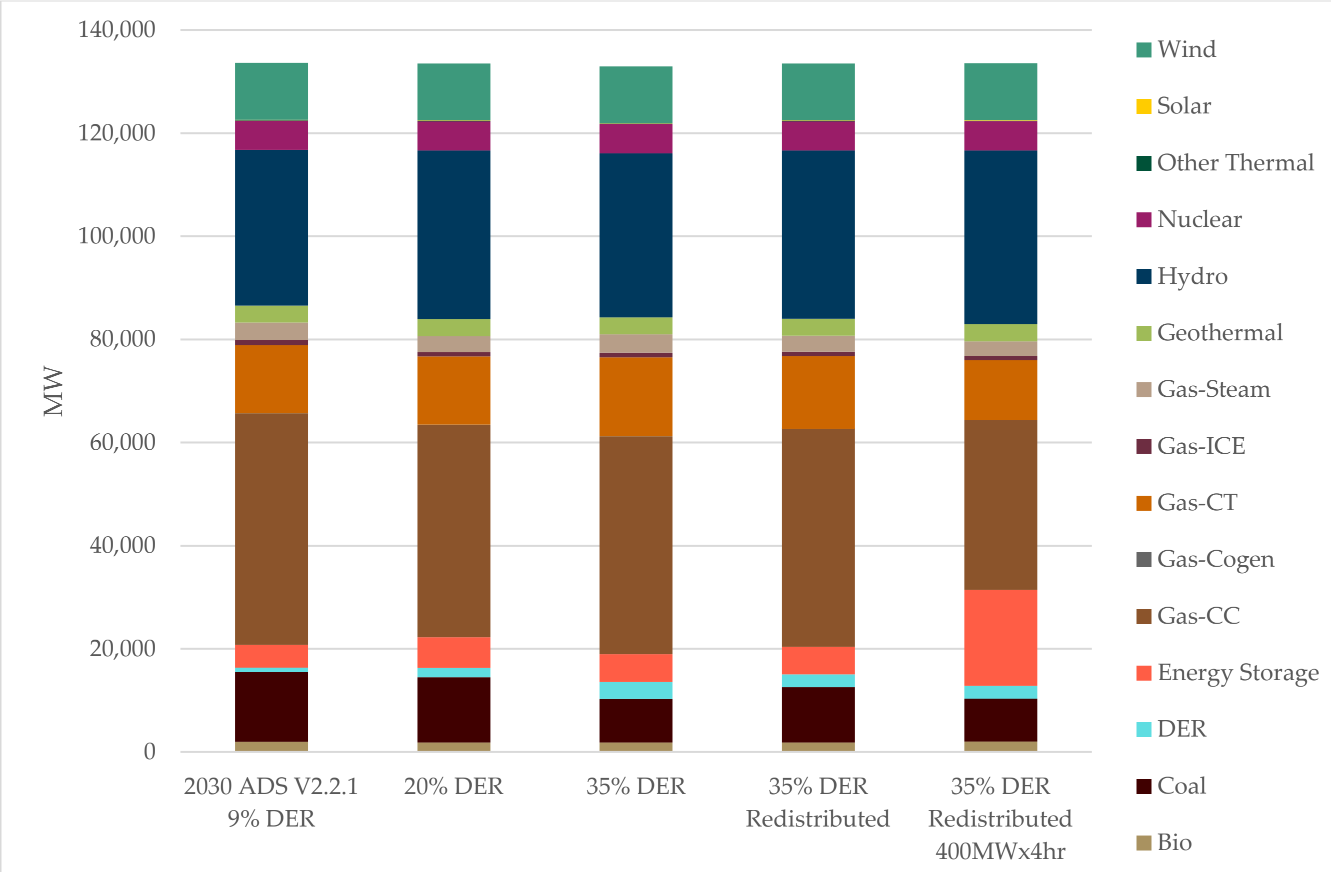

Figure 21: August 18, 2030, Hour 20 (8:00 p.m. MT)

Gas Generation Ramping

Gas generation ramping was much steeper in the evening ramp for cases with higher DER capacity because gas generation was not needed as much during the day due to DER providing more energy. Therefore, gas unit dispatch was reduced to a lower level during the day. However, the gas generation had to ramp back up for the evening hours as DER and other solar generation were ramping down. When comparing the 35% DER Redistributed case to the 35% DER Redistributed 400MWx4hr case, the gas generation ramping in the evening was not as steep for the 35% DER Redistributed 400MWx4hr case and peak energy level was not as high because the batteries were able to discharge during the evening ramp.

Figure 22 shows gas generation ramping. The types of generation that are considered “gas” are Gas-CC, Gas-Cogen, Gas-CT, Gas-ICE, and Gas-Steam.

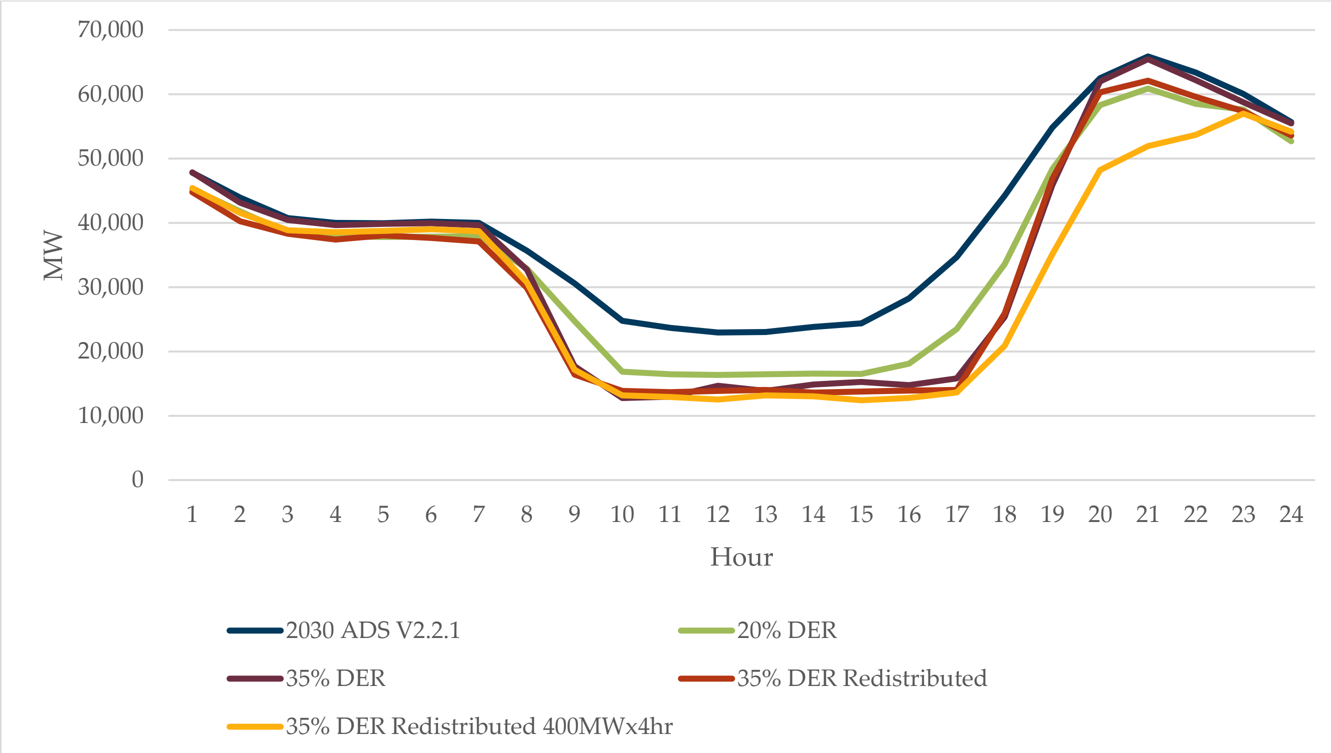

Figure 22: Gas generation ramp; August 18, 2030

Table 2: Gas generation ramping

Gas Generation Ramping			
Case	Bottom of Ramp (hour 15) (MW)	Top of Ramp (hour 21) (MW)	Difference (MW)
2030 ADS PCM V2.2.1 9% DER	24,385	65,888	41,504
20% DER	16,490	60,901	44,411
35% DER	15,288	65,464	50,176
35% DER Redistributed	13,766	62,119	48,353
35% DER Redistributed 400MWx4hr	12,414	51,929	39,515

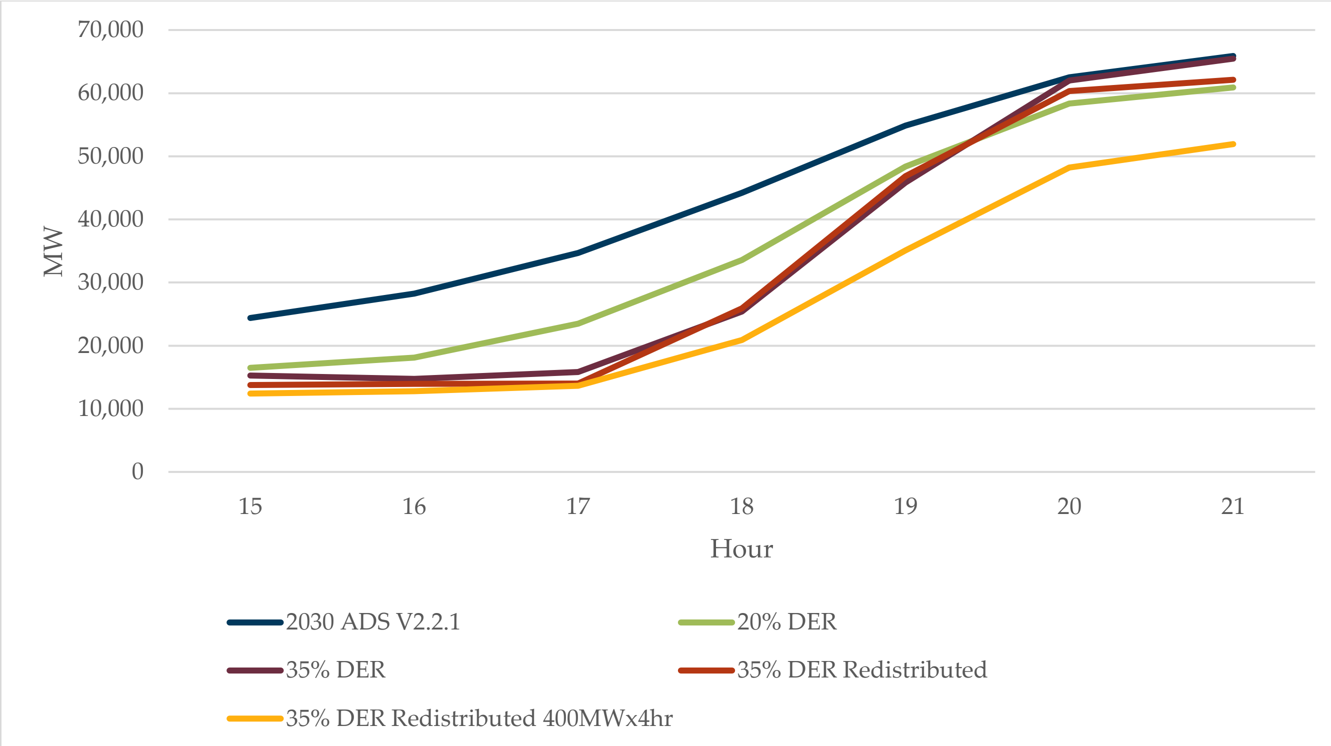

Figure 23: Magnified gas generation ramp; August 18, 2030

Gas Generation Ramping—CAISO Only

Figure 24 and Figure 25 show the gas generation ramping for California Independent System Operator (CAISO) only. The types of generation that are considered "gas" are Gas-CC, Gas-Cogen. Gas-CT, Gas-ICE, Gas-Steam.

The gas generation ramping in CAISO alone is steeper than the aggregated, interconnection-wide ramping seen in Figure 22 and Figure 23. This is due to much higher DER penetration in CAISO compared to the rest of the interconnection. Similar to the plots above, the gas generation ramping in the evening is not as steep in the case with batteries added because the batteries were able to discharge during the evening ramp, making it less steep.

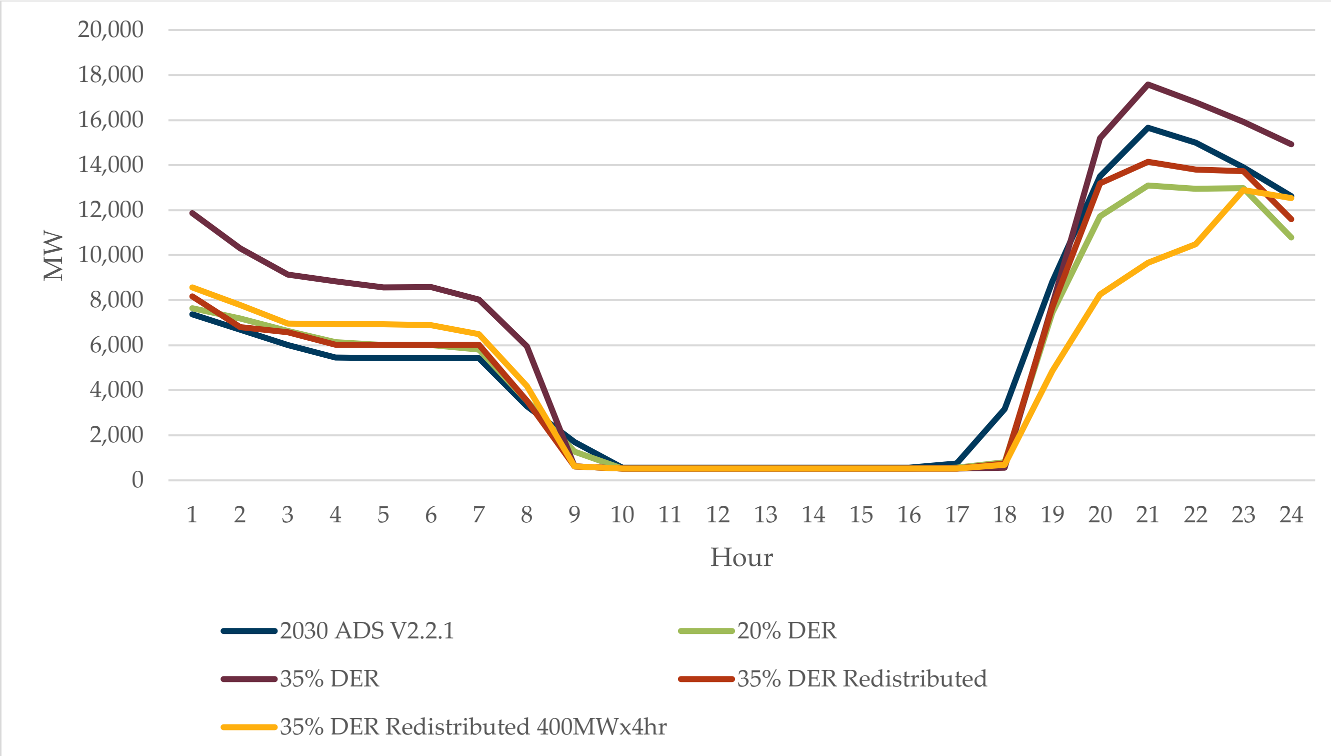

Figure 24: CAISO gas generation ramp; August 18, 2030

Table 3: Gas generation ramping—CAISO only

Gas Generation Ramping—CAISO Only			
Case	Bottom of Ramp (hour 17) (MW)	Top of Ramp (hour 21) (MW)	Difference (MW)
2030 ADS PCM V2.2.1 9% DER	754	15,660	14,906
20% DER	564	13,096	12,533
35% DER	526	17,581	17,056
35% DER Redistributed	526	14,147	13,621
35% DER Redistributed 400MWx4hr	526	9,666	9,141

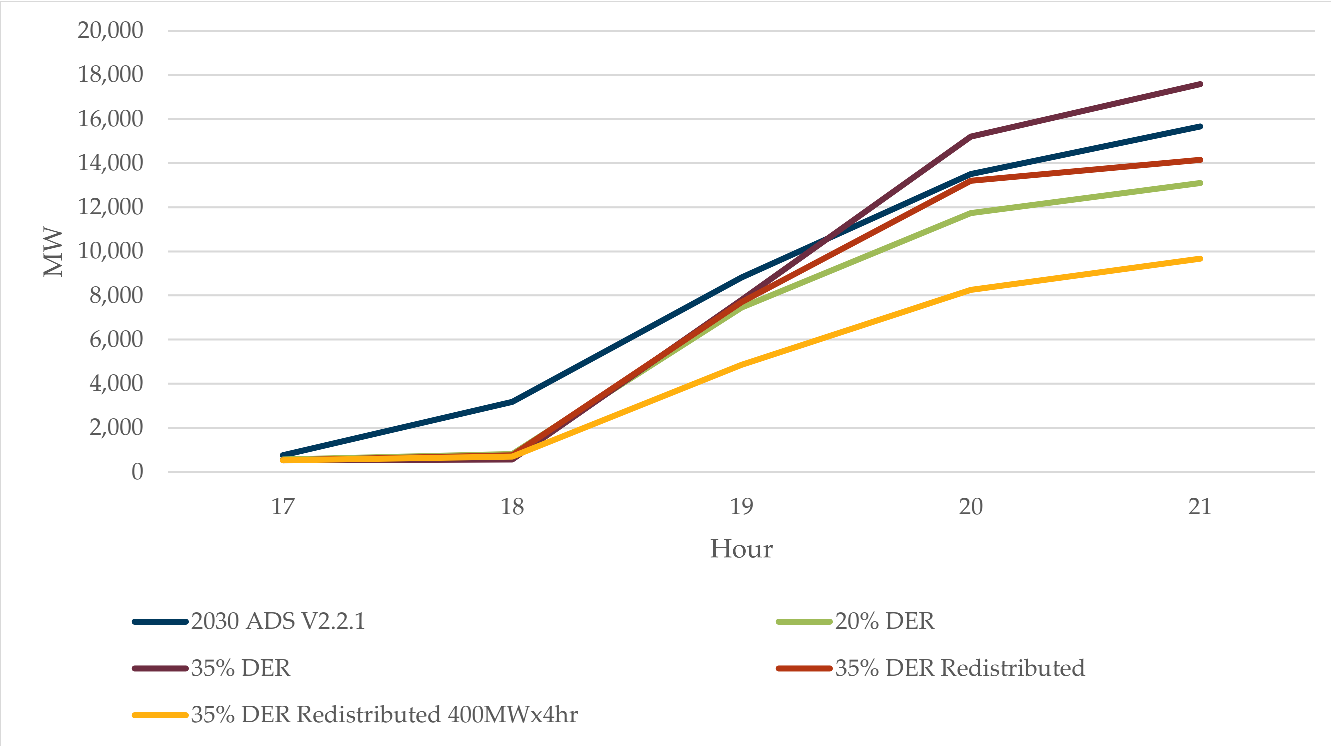

Figure 25: CAISO magnified gas generation ramp; August 18, 2030

Economic Impacts

For the cases with higher DER capacity, and especially for the hours when percentage of DER energy was high, certain economic impacts were seen that may need further examination. Figure 26 shows that in the 35% DER case average annual LMPs were negative for many regions. This means that the energy was being produced in excess of demand and the value of the energy decreased so much that it became negative. When the value of energy is negative, the generation profile is not feasible. This points to the issue that when large amounts of DER are added to the system without careful generation profile planning considerations at the bulk level, system economics may see significant impacts. A careful examination of generation planning will be necessary to bring the policy objectives of high DER penetration to fruition. These considerations could include examination of market/rate design, management systems of resources, and addition of battery storage or hybrid (e.g., solar/wind plus battery) systems.

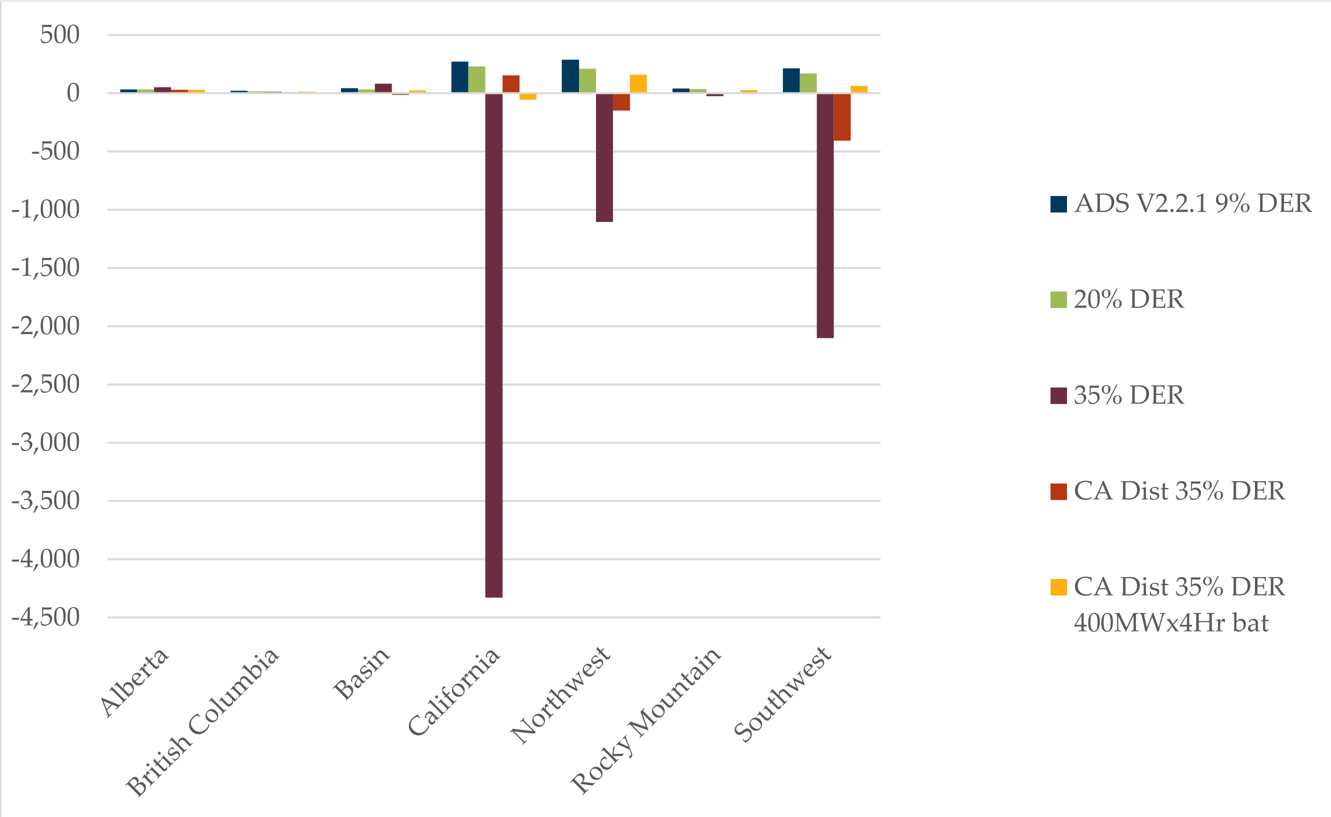

Figure 26: Average LMP For Various Regions ($/MWh)

Transmission Flows

Various changes to transmission flows were seen at different levels of DER penetration. Figure 27 through Figure 36 show, in the 2030 ADS PCM V2.2.1 case, most of the time the Pacific DC Intertie (PDCI) and California–Oregon Intertie (COI) flow into California. However, as more and more DER are added to California, power is forced out of California, causing a more frequent reversal of flows on these paths. For example, the DER additions in the 35% DER case caused the COI to flow south to north about half the time instead of primarily flowing north to south as in the 2030 ADS PCM V2.2.1 case. However, when some of the DER were distributed out of California, there was less frequent reversal of flows on PDCI and COI.

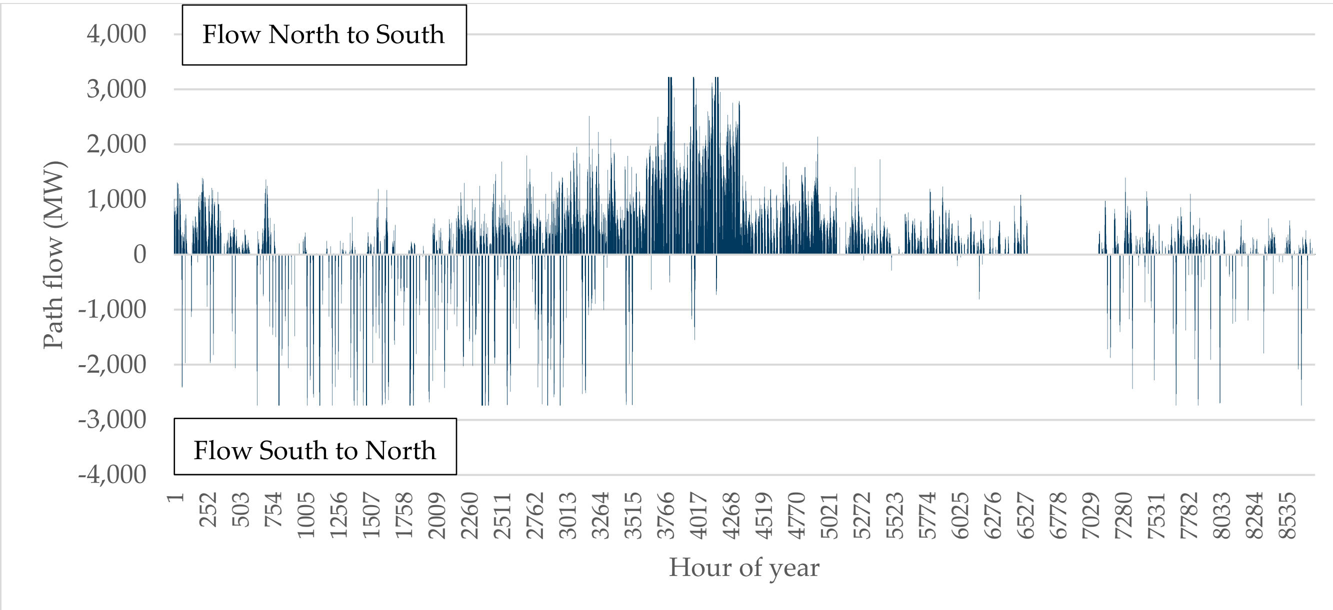

Figure 27: ADS PCM V2.2.1 9% DER PDCI

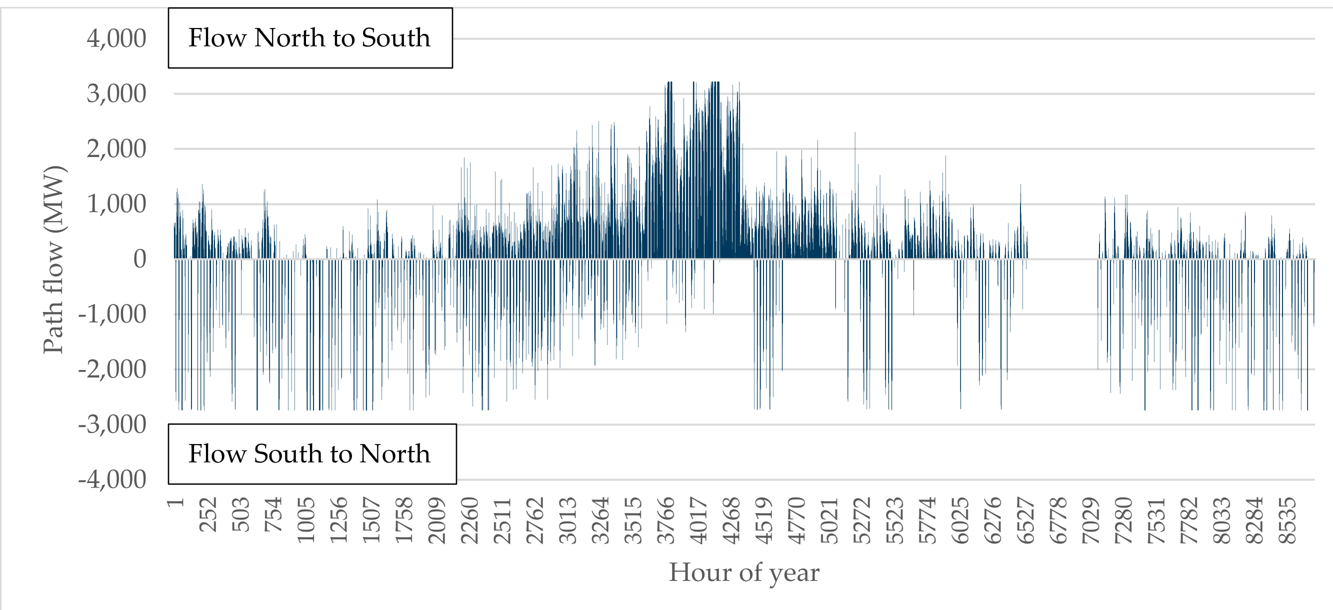

Figure 28: 20% DER PDCI

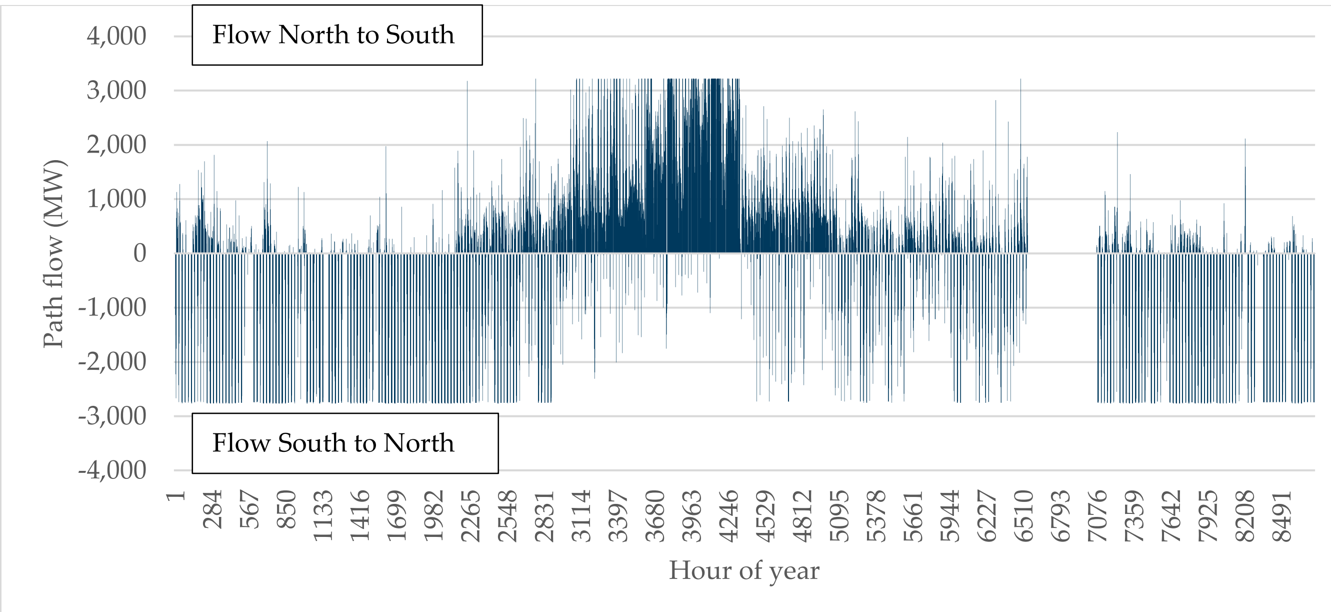

Figure 29: 35% DER PDCI

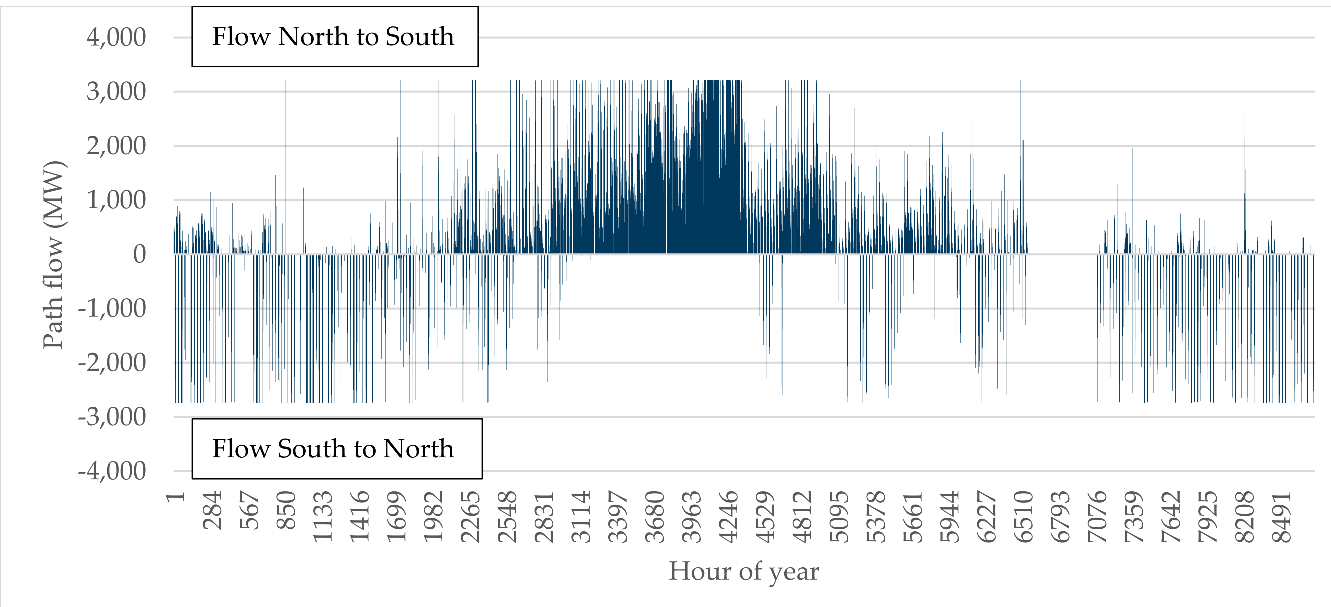

Figure 30: 35% DER Redistributed PDCI

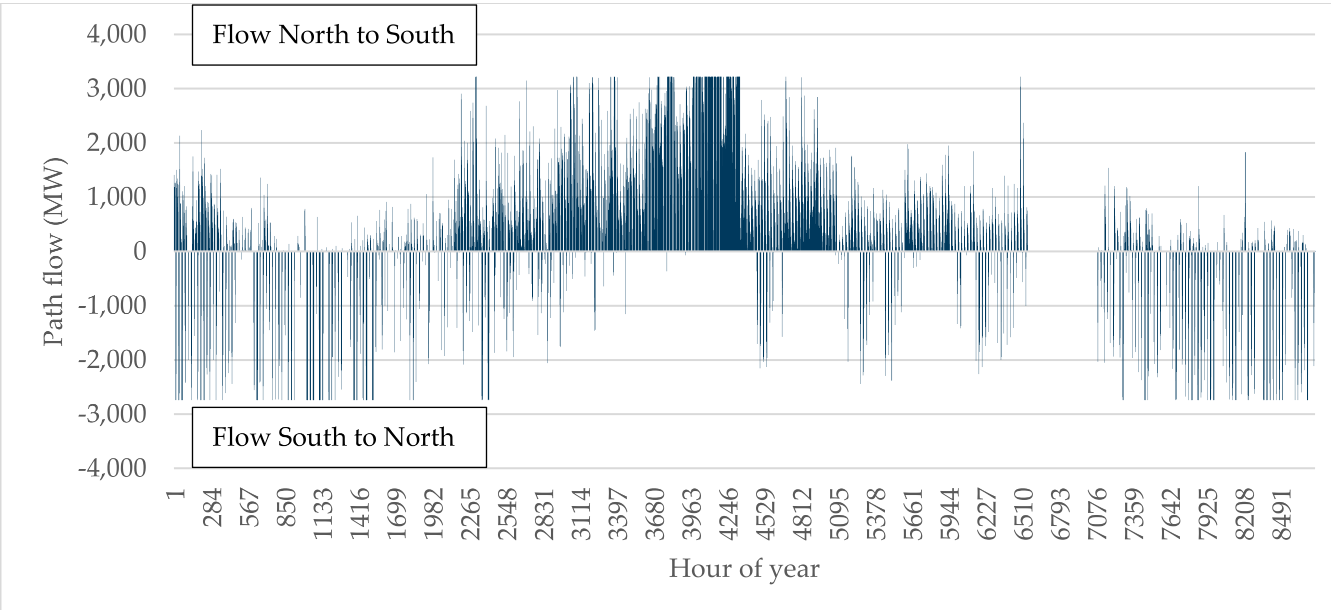

Figure 31: 35% DER Redistributed 400MWx4hr PDCI

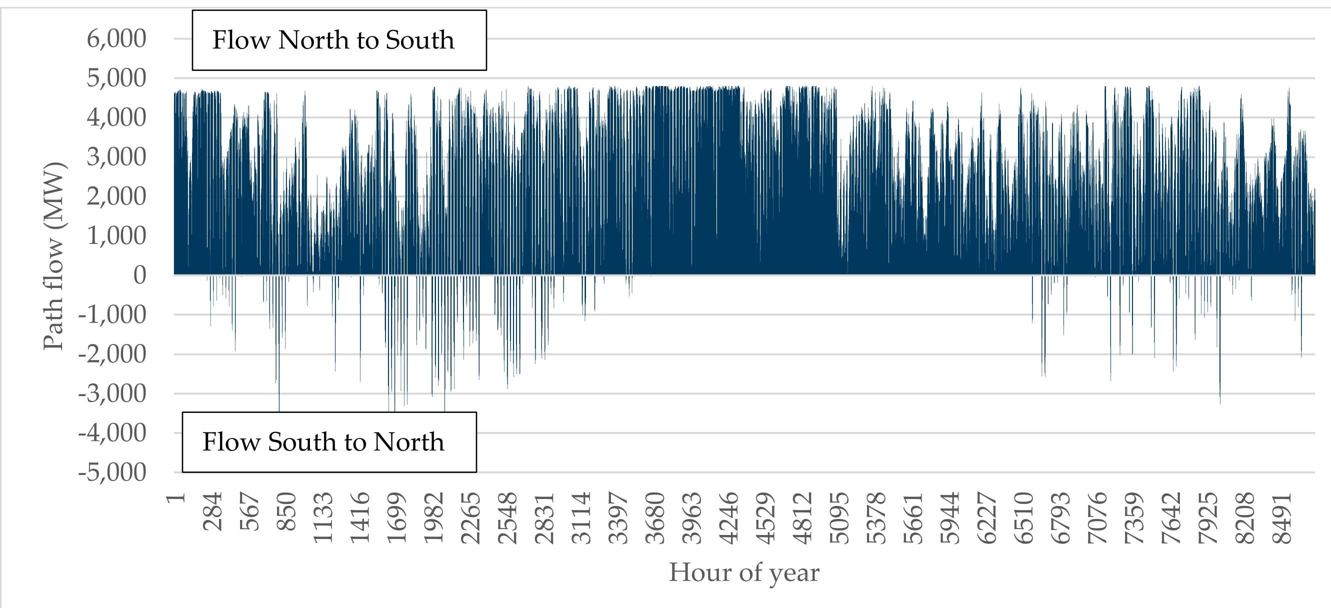

Figure 32: ADS PCM V2.2.1 9% DER COI

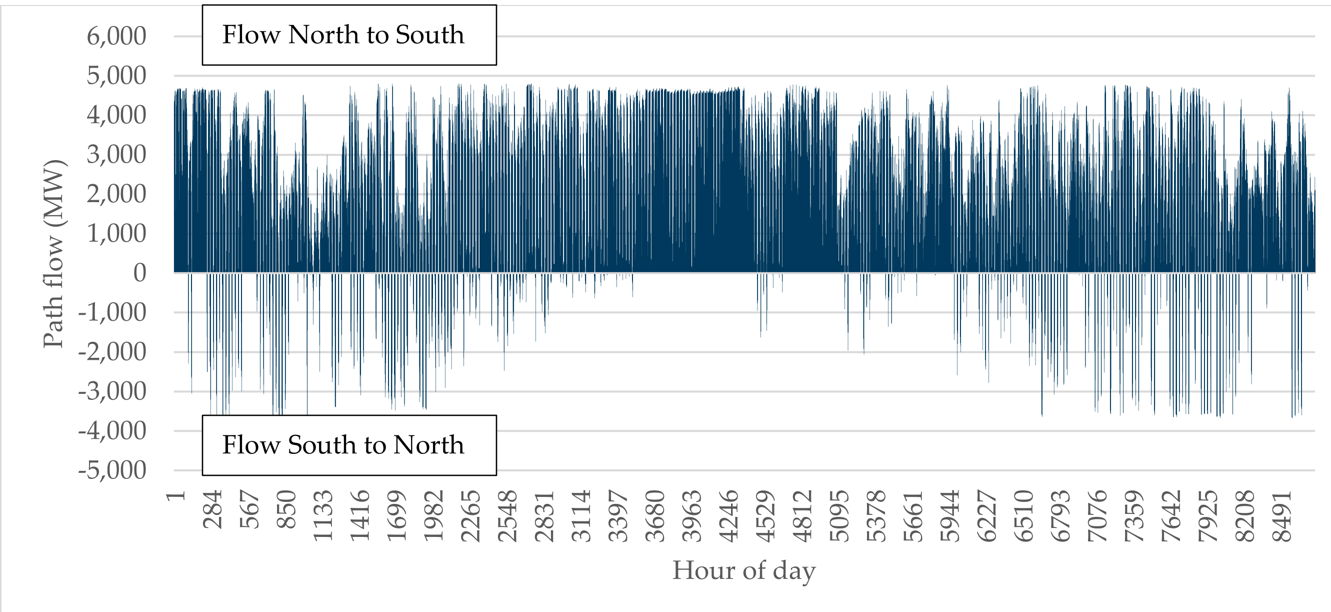

Figure 33: 20% DER COI

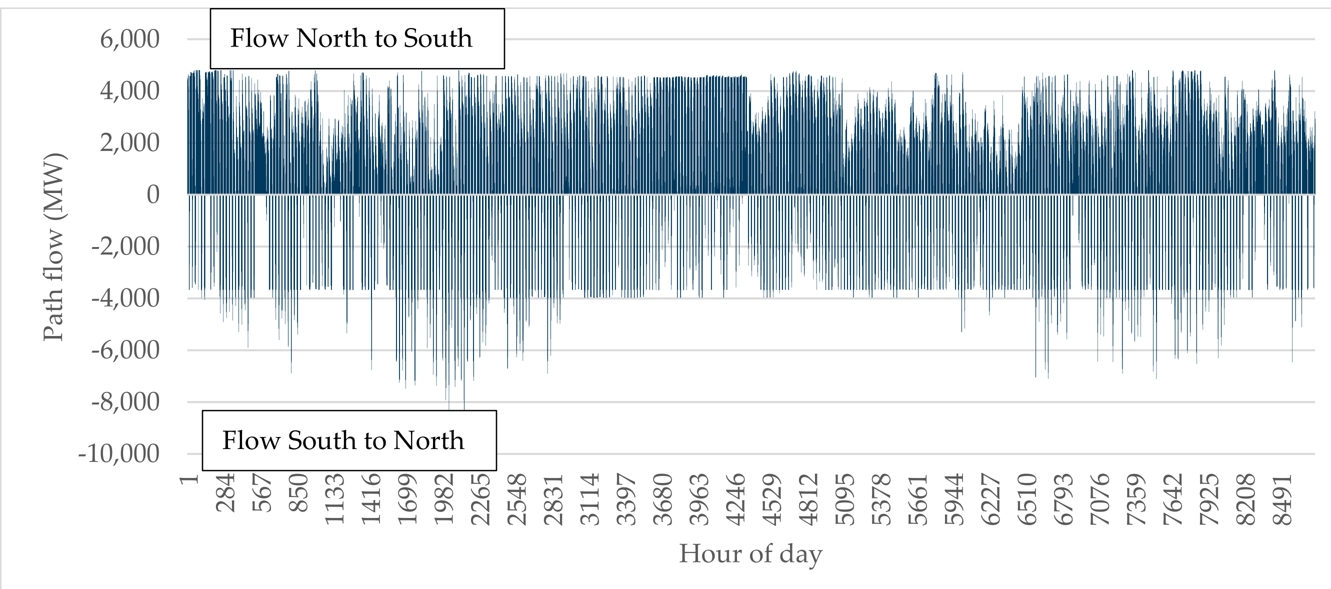

Figure 34: 35% DER COI

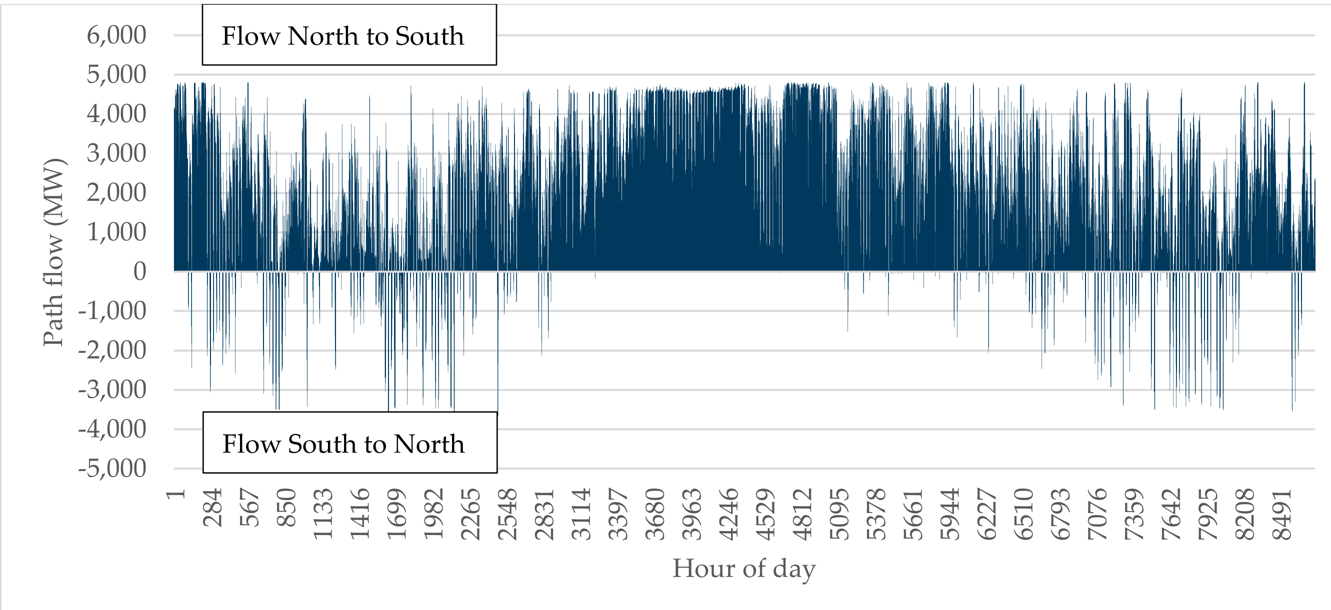

Figure 35: 35% DER Redistributed COI

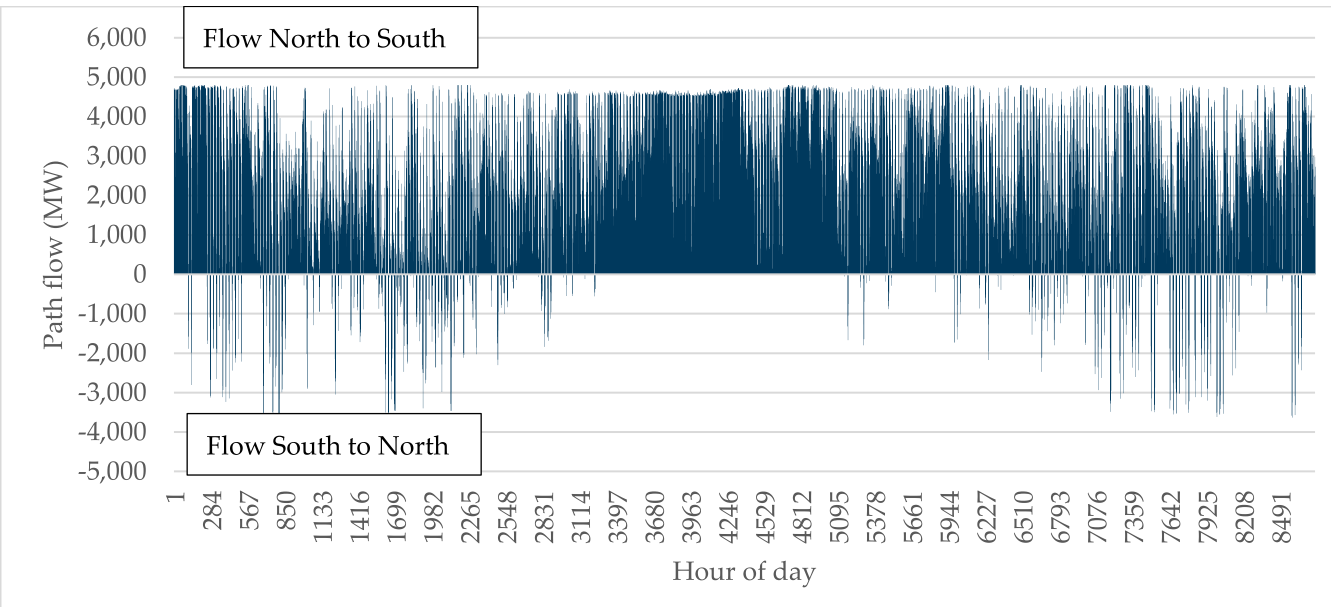

Figure 36: 35% DER Redistributed 400MWx4hr COI

Power Flow and Dynamics

In the power flow and dynamics analysis, two cases were studied. The baseline case was the 2030 HS1a1 with 1.9% of load served by DER, with the other being the 20% load served by DER case (20% DER PF).

In the 20% DER PF case, 40 GW of generation was displaced by DER, which decreased transmission losses. The steady-state voltage profiles shifted in response to this, with most buses seeing an increase in voltage. However, there were some portions of the system where voltages decreased. Due to the high voltages seen, some generators started to consume volt-amperes reactive (VAR) to bring regulated voltages down. This led to decreases in voltage at generator buses as well as at buses near the generators. In other cases, it was due to Synchronous Condensers or Static VAR Compensators switching and depressing voltages locally to control the overall increase in voltages.

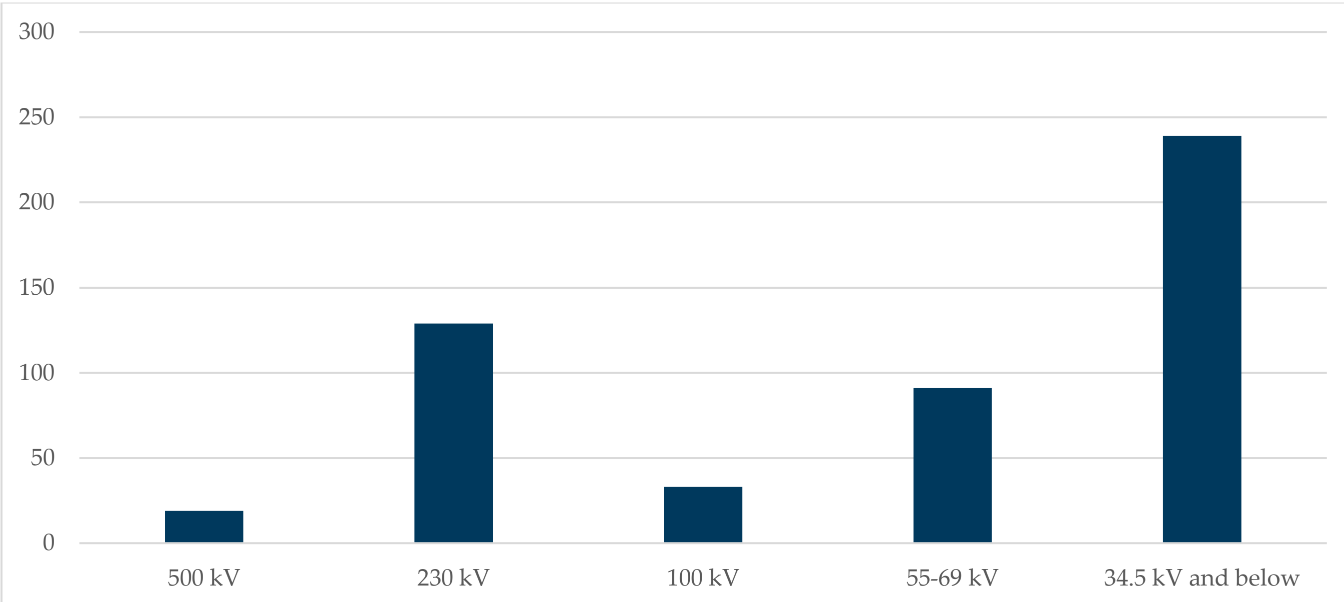

Figure 37: Buses with a greater than 5% increase in voltage

A post-transient analysis was conducted on both cases (20% DER PF and 2030 HS1a1). A post-transient analysis is a power flow analysis representing steady-state conditions after a disturbance. For this study, a post-transient analysis of a simultaneous outage of two Palo Verde generating units was performed. Following the outage, available units across the interconnection adjust output to make up for the lost generation. In the post-transient condition, no bus voltage shifted more than 10% in the 2030 HS1a1 and the 20% DER PF cases. All buses whose voltage shifted by more than 5% in the 2030 HS1a1 case also shifted by more than 5% in the 20% DER PF case. Additionally, 137 buses shifted by more than 5% in the 20% DER PF case.

A comparison of the resulting generator dispatch after the Double Palo Verde outage for both 2030 HS1a1 and 20% DER cases can be seen below in Figure 38.

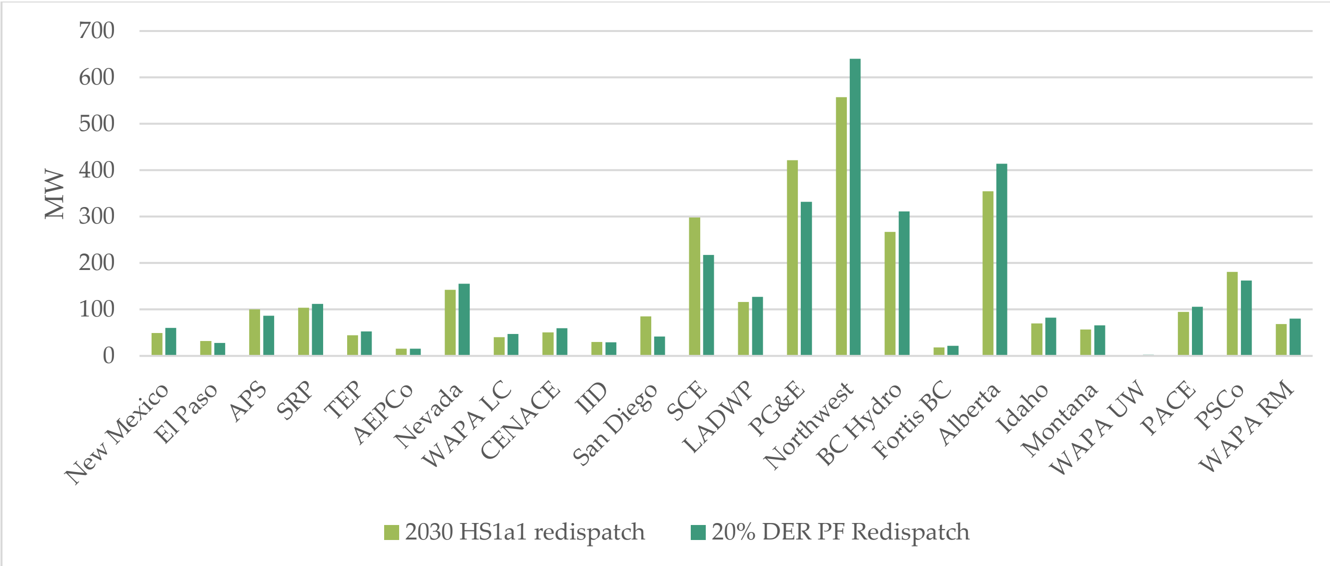

Figure 38: Generation redispatch after Double Palo Verde outage by area

Areas with a large increase in DER in the 20% DER PF case saw a decrease in the amount of post-contingent redispatch, while areas with a relatively small increase in DER saw greater redispatch (as their dispatchable units were available to make up a greater portion of the response).

Dynamics

In the dynamics analysis, standard disturbances as listed in Appendix B were simulated in the 20% DER case. The dynamic simulations were sensitive to the type of DER model used at 20% DER penetration. When the CA Rule 21[8] models were used for the simulations, significant power oscillations were seen when standard disturbances were simulated which resulted in challenges with analyzing the system. Therefore, it was decided to use an older version of the DER model—IEEE-1547-2003—which resulted in relatively stable simulations for standard disturbances. Further analysis is necessary to determine whether there are any issues with the CA Rule 21 models or whether an actual system response for standard disturbances would result in increased oscillations. An example of this oscillation is shown in Figure 39 when CA Rule 21 models were used.

[8] https://www.cpuc.ca.gov/Rule21/

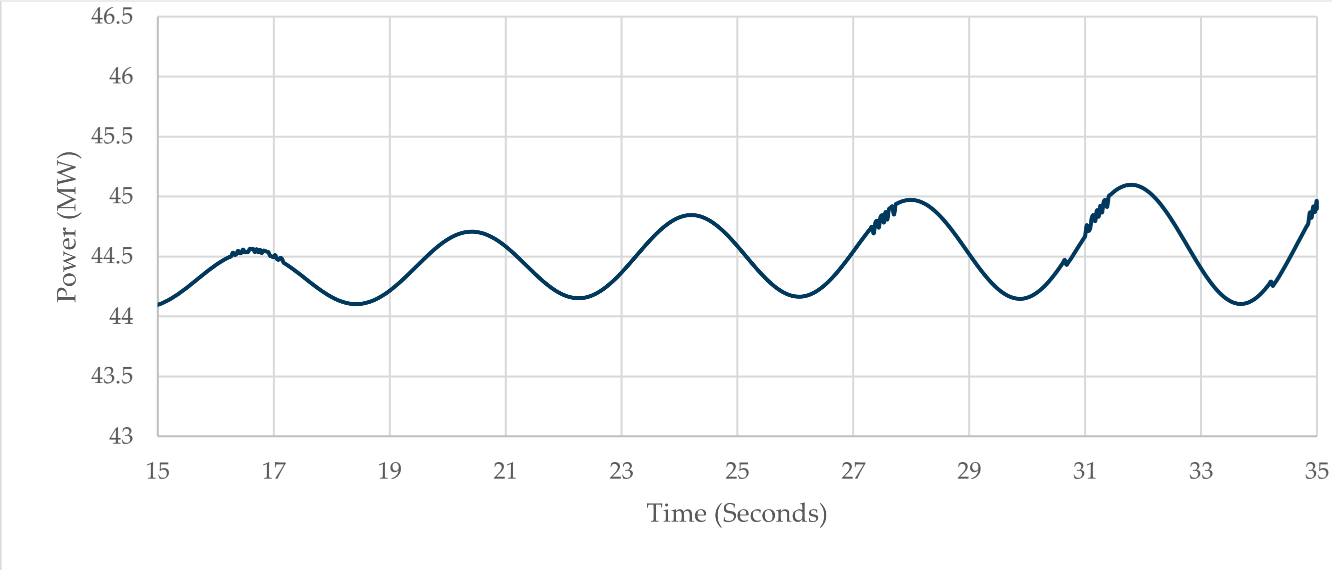

Figure 39: DG power at bus 30941 on the Diablo–Midway outage

The case combinations shown in Table 4 were simulated.

Table 4: Dynamics Cases

Case Name	Case Description
2030 HS1a1	• 2030 HS1a1 PF with IEEE-1547-2003 DER models as a baseline (no dynamic voltage controls)
20% DER	• 20% DER PF with IEEE-1547-2003 DER models (no dynamic voltage controls)
Vrfrac1	• 20% DER PF with IEEE-1547-2003 DER models with the Vrfrac[9] parameter set to 1 (no dynamic voltage controls)
Voltage Controls	• 20% DER PF with IEEE-1547-2003 DER models with dynamic voltage controls enabled (Vrfrac = 0)

To evaluate system performance for each case, the amount of load shed due to voltage and frequency response was monitored.

The loads are represented using a composite load model developed by the WECC Modeling and Validation Subcommittee (MVS). Depending on the climate and feeder type, the load is represented by assigning certain values to each load parameter. A set of these parameters are related to voltage where

[9] In the model, the parameter Vrfrac controls what fraction of panels return to service after a severe voltage dip. Setting this to 1 represents more advanced panels capable of quickly returning to service.

the model trips a percentage of the load based on voltage performance. If the voltage magnitude at the far end of the feeder bus drops below a specific threshold for a certain duration, some of the load is tripped. Depending on the model, some or all of that load may return after a certain amount of time. The model includes triggers for frequency as well, but, in this study, the system frequency did not decrease enough to trigger any load loss due to frequency. The load shed amount due to low voltages during the disturbance simulations is shown in Figure 40.

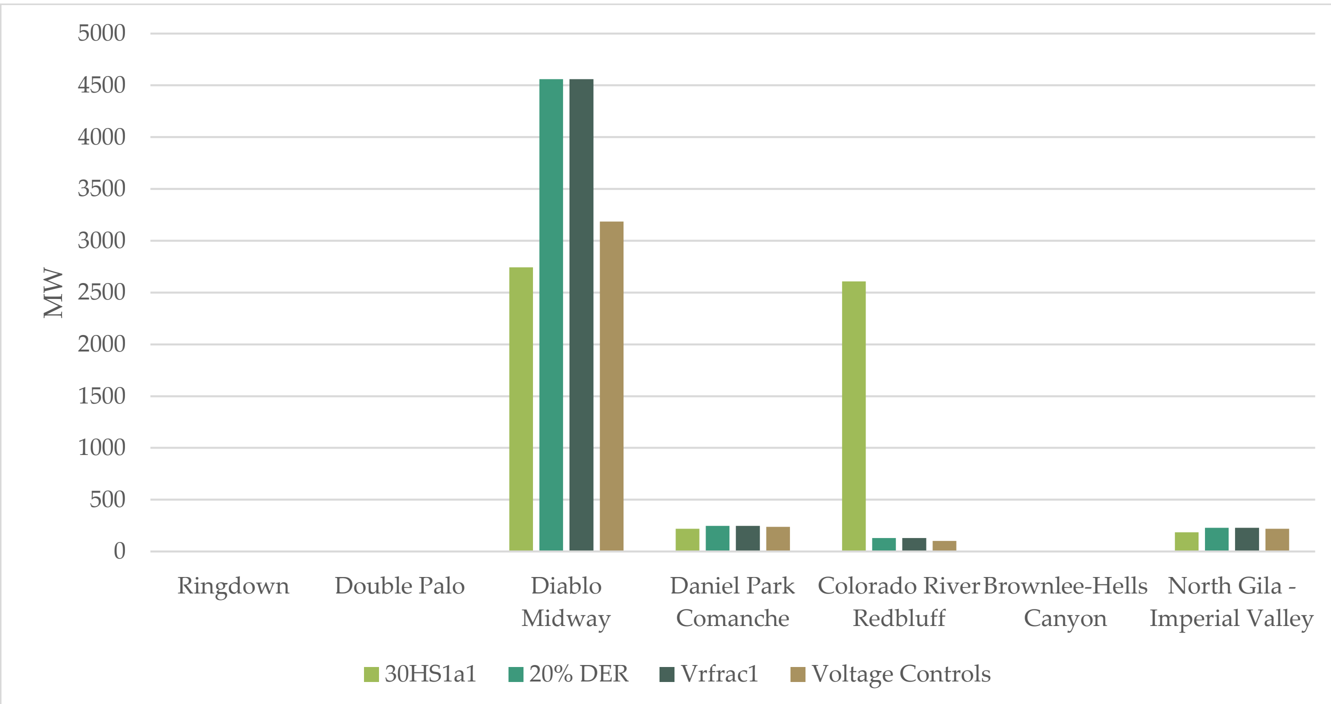

Figure 40: Load shed due to voltage in the composite load model for various outages

The Diablo–Midway outage showed increased load loss for cases with 20% DER, while the Colorado River–Redbluff outage showed a significant decrease in load lost for cases with 20% DER. In both cases the amount of load loss was highly dependent on and sensitive to small changes in the amount of time the voltages stayed below the tripping threshold in the simulation.

Figure 41 shows the voltage plot for one load for the Diablo–Midway outage simulation. The voltage dips lower in the cases with 20% DER, but it returns above the tripping threshold at almost the same time as in the 2030 HS1a1. However, the second dip during the recovery of the load for cases with 20% DER is below the voltage tripping threshold for the Motor-A[10] component of the composite load model. This causes an additional amount of the Motor-A component to be tripped in the cases with 20% DER.

[10] Motor-A represents three-phase compressor motors used in air conditioners and refrigerators.

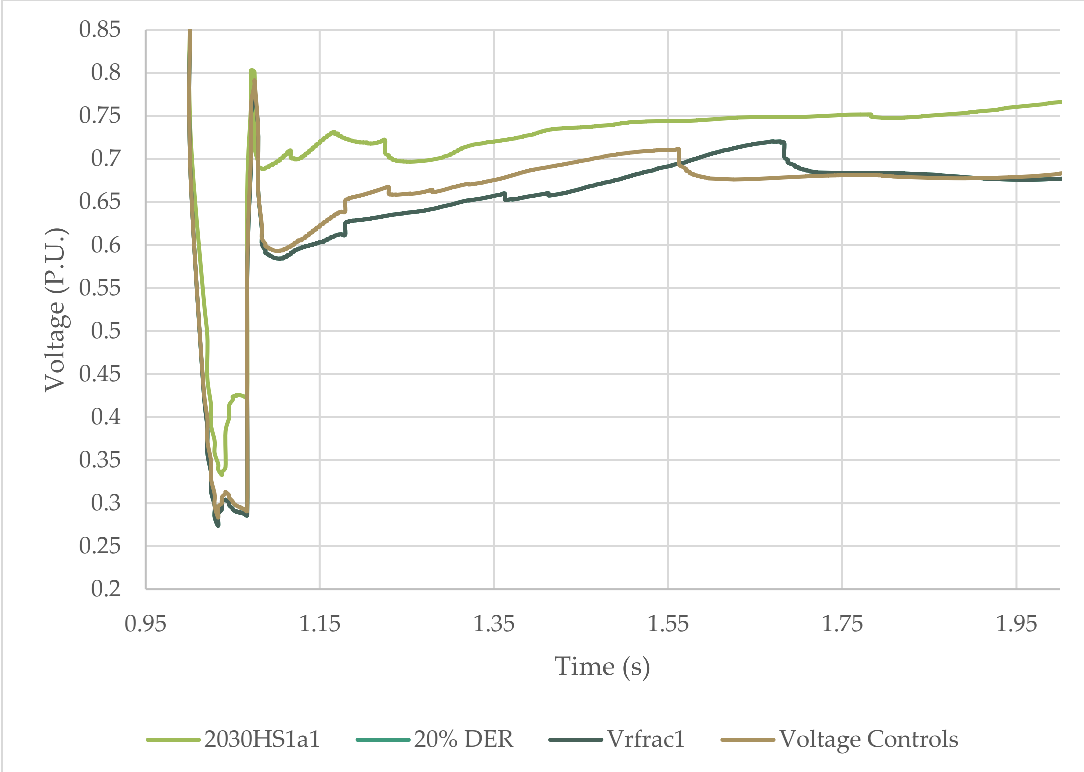

Figure 41: Bus 30941 load voltage during Diablo–Midway outage

Figure 42 shows the voltage for a load during the Colorado River–Redbluff outage. The dark green trace with the slow recovery is from the 2030 HS1a1. The initial recovery time is slow enough that the Motor-D[11] component of the load enters into a stall, which leads to the overall slow recovery. The voltage only recovers when all the Motor-D components trip. The voltage at this load in the cases with 20% DER drops below the stall threshold a few cycles later than the voltage at this load in the 2030 HS1a1. However, the voltage recovers at the same time in all cases. This means the voltage in the 20% DER cases does not stay low enough and for long enough to cause the load to stall. The Motor-D components do not enter stall, so the voltage recovers quickly, and the load is not lost. This can be seen more clearly in Figure 42.

[11] Motor-D represents single phase air conditioner motors.

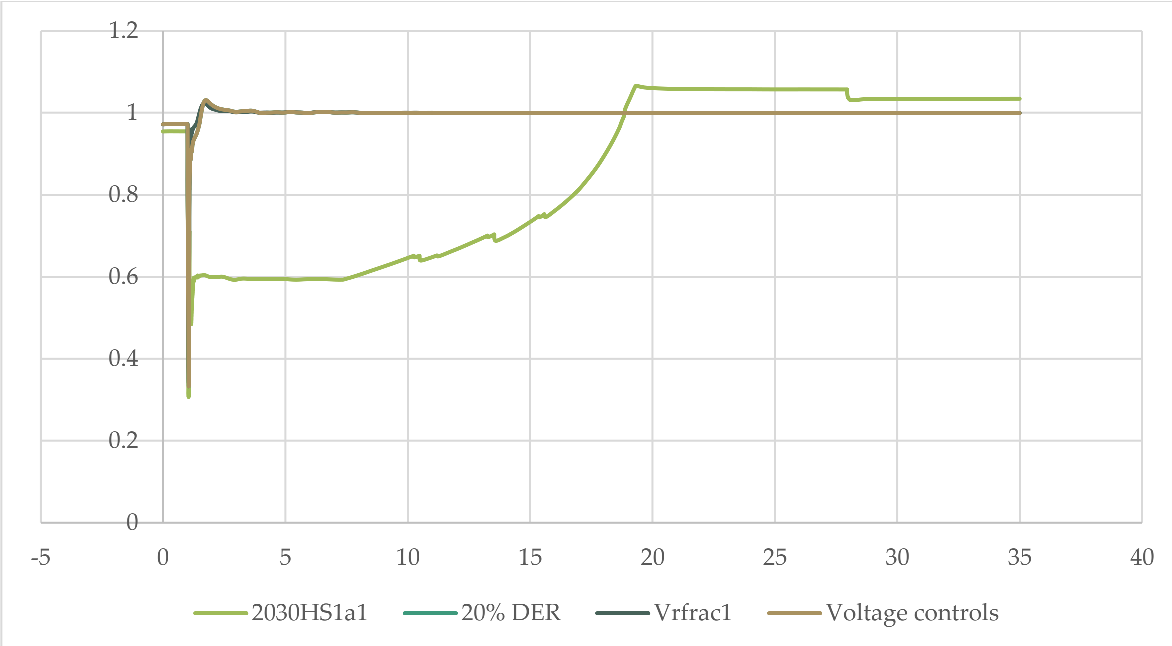

Figure 42: Bus 24229 voltage during Colorado River–Redbluff outage

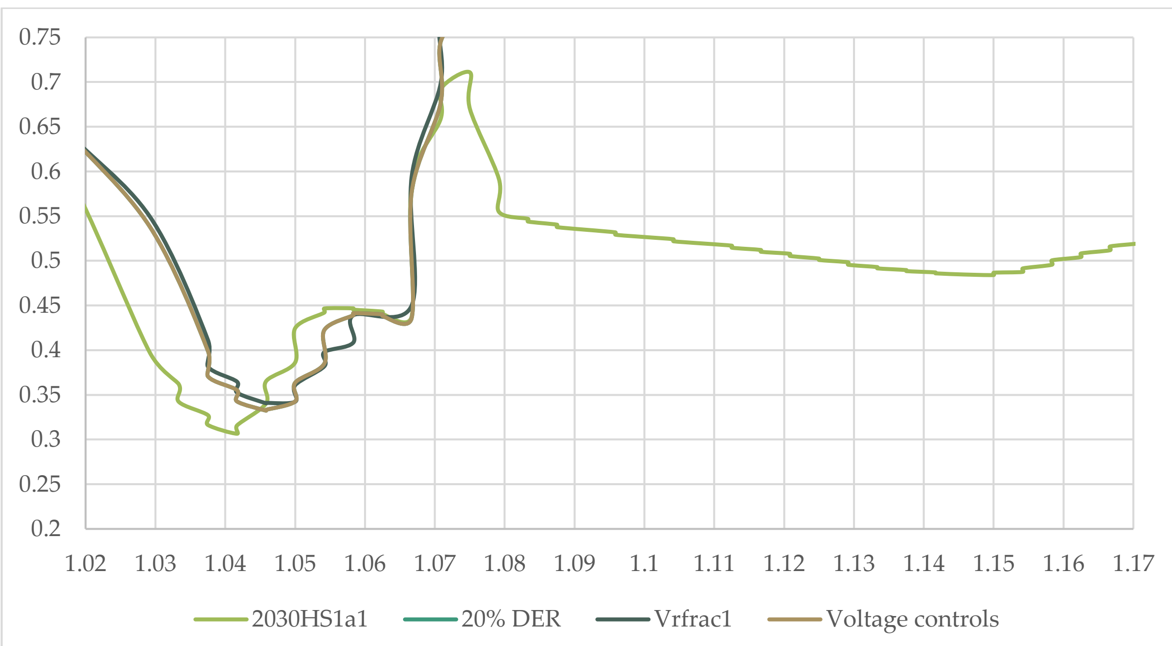

Figure 43: Closer view of Bus 24229 voltage during Colorado River–Redbluff outage

Frequency was the second metric used to evaluate system performance in this study. Frequency during these outages did not drop low enough to trigger modeled underfrequency load shedding relays. Figure 44 is the frequency response plot for the Colorado River–Redbluff outage. The frequency in the 2030 HS1a1 increases because load was shed in the composite load model due to low voltages. Relatively little load is shed in the 20% DER case, so a similar response is not seen for the same outage.

A small swing down in the initial frequency is seen in Figure 44; this is due to temporary shifts in load and generation as the disturbance propagates out toward the bus where frequency was measured.

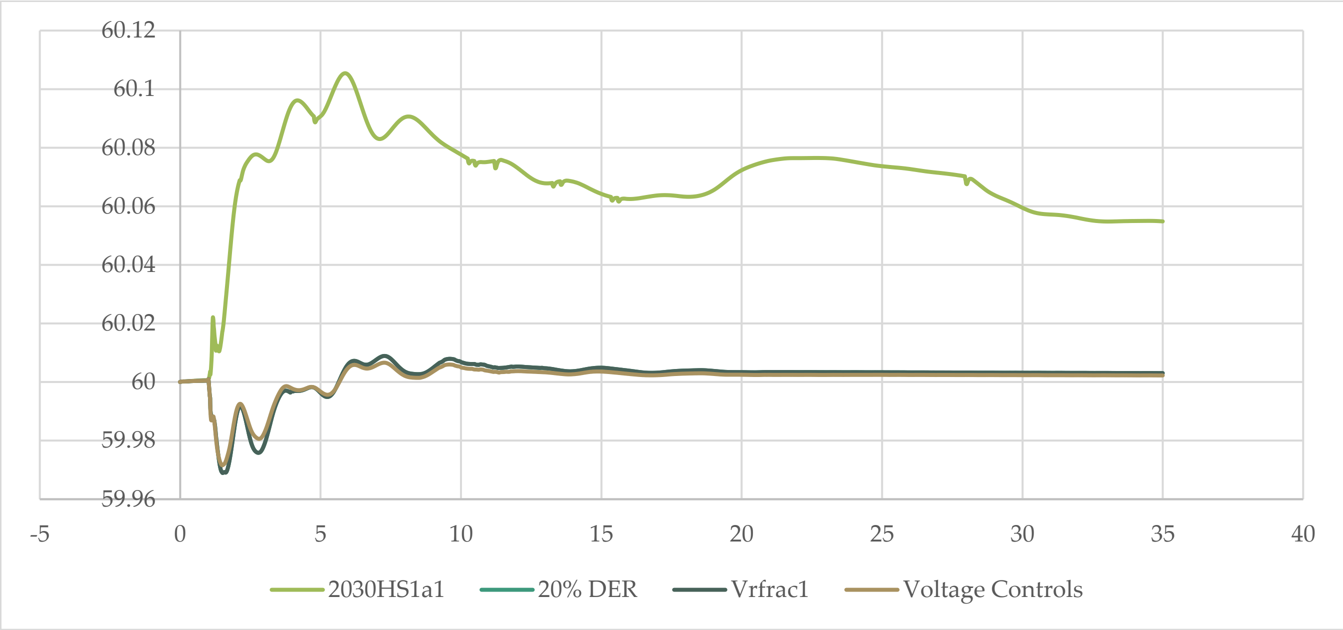

Figure 44: Frequency response during the Colorado River–Redbluff outage

The Diablo–Midway outage simulations exhibited load shedding in the composite load model due to low voltages, which resulted in increased system frequency in all of these cases, as seen in Figure 45.

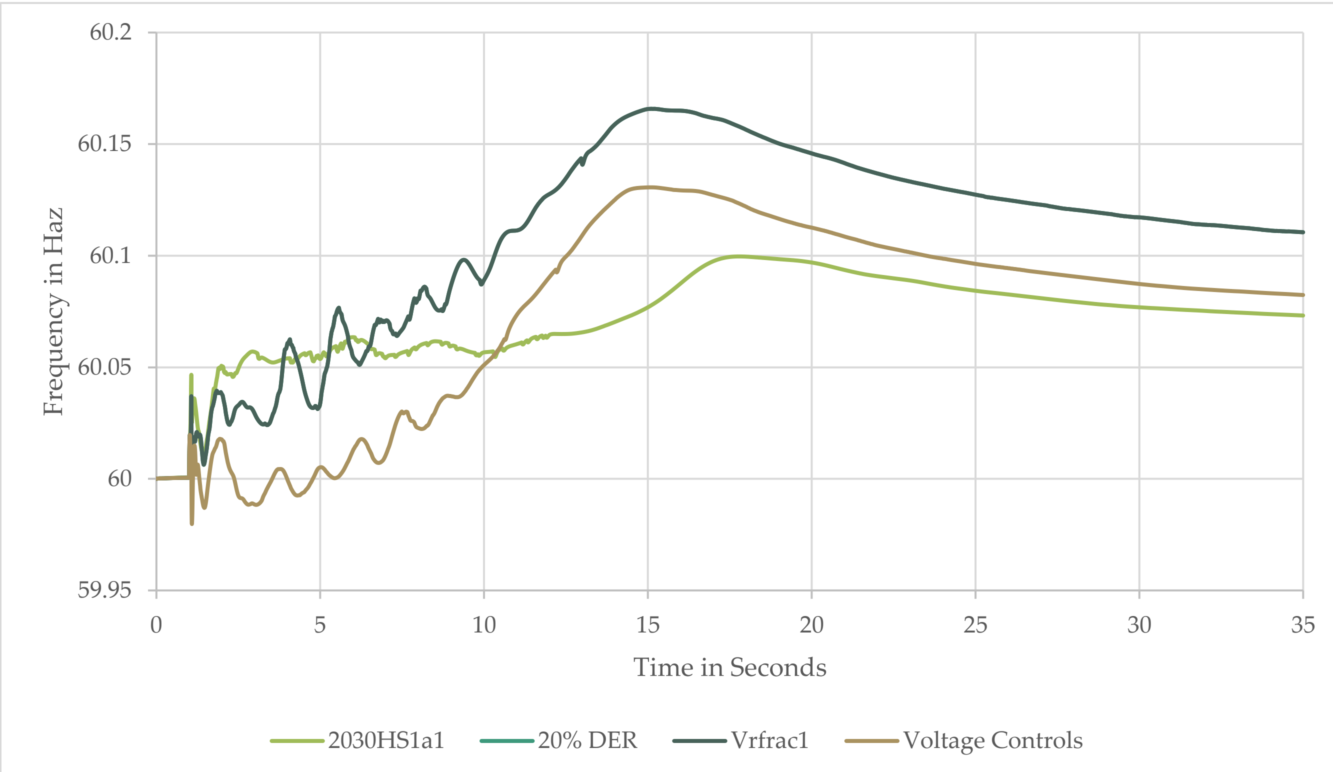

Figure 45: Frequency response during the Diablo–Midway outage

The Double Palo Verde outage is a loss of 2,700 MW of generation. For the Double Palo Verde outage simulations, there was no load lost, because the voltages and frequency did not drop low enough to trigger load shedding. Figure 46 shows that all the simulations for 20% DER case followed the same lower trace. The DER did not have frequency responsive controls enabled, so the smaller pool of synchronous generation took longer to bring the system frequency up. The system frequency did not drop enough to trigger underfrequency load shedding.

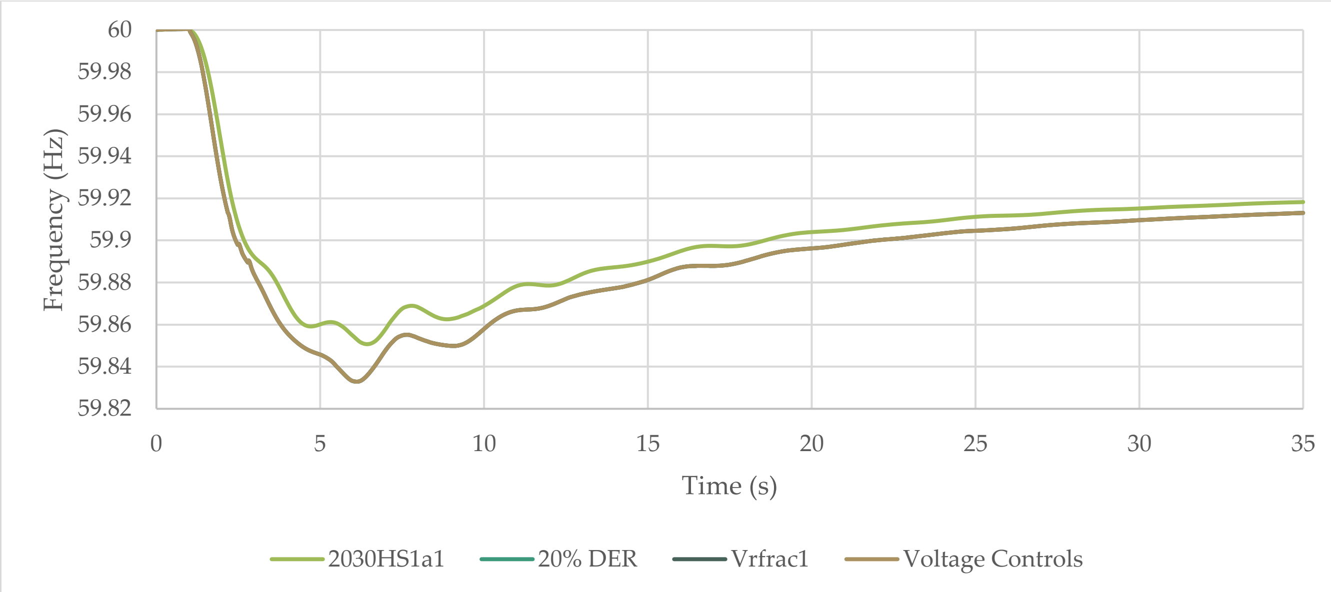

Figure 46: Malin 500 frequency response during the Double Palo Verde outage

Another metric that was used to evaluate system performance was the Interconnection Frequency Response calculated in MW/0.10 Hz. This metric is intended to represent the capability of the interconnection to respond to sudden generation loss and arrest the subsequent decline in frequency. This calculation was done for the Double Palo Verde outage. The original case had a response of 1733 MW/0.10 Hz. A decline in frequency response was seen in the cases with 20% DER, where frequency response was 1578 MW/0.10 Hz. A frequency response of 1578 MW/0.10 Hz is still well above the NERC-recommended IFRO of 858 MW/0.10 Hz for the Western Interconnection. A decline was seen in system frequency response when comparing the 2030 HS1a1 simulation to the 20% DER simulations due to lack of frequency response contribution from the added DER, which replaced conventional generation, some of which was frequency responsive.

Future studies could be performed with frequency response enabled for DER and tuned to represent DER capabilities that are in IEEE 1547-2018 standard. However, unless DER inverters were required to operate with headroom, they would still not contribute to the frequency response when needed.

The frequency response for the other disturbances was not plotted here, as the load or generation lost in those disturbances was relatively small and did not lead to significant changes in system frequency.

Conclusions

In this study, impacts of adding different levels of DER to the system were analyzed. Increasing amounts of DER offset a large amount of generation such as coal and other thermal units. However, due to large amounts of DER on the system, certain issues such as steeper evening ramping requirements and negative LMPs became more prominent. Adding batteries to the system helped alleviate such issues.

Voltage profiles shifted higher as DER were added to the system. However, some voltage profiles decreased in magnitude as voltage control equipment compensated for higher voltages. Significant increases in DER may call for more voltage support to mitigate these shifts in voltage profiles.

The impact to post-contingency load loss was not consistent among simulated outages. For some contingencies with added DER, there was more load loss compared to the 2030 HS1a1 case, while, for other contingencies, the amount of load loss was reduced with the added DER. Increased amounts of DER could significantly affect voltage profiles which could result in significant differences in load loss due to impacts to dynamic voltage response under certain disturbances.

Careful planning when adding DER to the system (the right amount in the right areas) will improve system reliability. Conversely, if DER are added without careful planning (concentrated in limited areas without regard to economics and impacts to voltages), DER expansion could lead to economic issues, such as negative LMPs, and reliability issues, such as increased load loss.

Table 5: Reliability Implications

Reliability Implications	
Scenario	**Distribution system and customer load impacts on the transmission system**
20% DER PCM Case	No major system impacts seen.
35% DER PCM Case	The average LMP is extremely negative due to the excess generation during the day.
35% DER Redistributed PCM Case	The average LMP is negative due to the excess generation during the day, but not as much as the 35% DER PCM case.
35% DER Redistributed PCM Case with 400 MW x 4-hour battery storage	No major system impacts observed.
20% DER Power Flow and Dynamics Case (20% DER PF)	Voltage profiles shifted, in some cases significantly. Presence of DER affected load loss due to dynamic voltage response during simulations.

Observations and Recommendations

Observations

PCM

- Some major transmission corridors such as California-Oregon Intertie and Pacific DC Intertie experienced increased south-to-north flows as more DER were placed on the system.
- DER did not displace all thermal generation during the day; some thermal units remained on-line for operational or reliability requirements.
- Negative LMPs were seen in the 35% DER PCM cases. However, when 15,200 MW capacity (60,800 MWh energy) of battery storage was added, the average LMP became positive.
- Large amounts of utility-scale solar and wind curtailments were seen in the 35% DER PCM cases.
- Thermal units saw reduced energy output in all cases with high DER penetration compared to the 2030 ADS PCM V2.2.1.
- High concentration of DER in California resulted in many of the issues—negative LMPs, flow reversals on transmission and voltage profile issues, etc.

Power Flow and Dynamics

- In general, steady-state voltage profiles increased in magnitude with higher DER penetration
- The system response seen with the added DER was not consistent in terms of voltage profiles throughout the system. In some instances, during fault condition simulations (dynamics runs), increased DER led to more low voltages at load buses, which led to increased load loss when compared to the 2030 Heavy Summer base case. In other instances, the presence of DER on the system improved voltage profiles at load buses and resulted in decreased load loss.
- Under disturbance conditions, undamped oscillations were seen for DER when frequency controls were enabled.

Recommendations

It is recommended that entities carefully plan the system with increasing levels of DER. With increased levels of DER, the evening system ramp requirements will continue to increase, and operating and planning entities must carefully analyze and plan for anticipated increased levels of DER to avoid reliability issues. Planning and operating entities should continue to collect more detailed data on DER (magnitude and location) so they can adequately plan the system.

The Production Cost Data Subcommittee (PCDS) should carefully review generation units labeled "Must Run" in the datasets. Must Run units were always dispatched in the simulation and could not be curtailed. Further analysis is needed to verify Must Run assumptions in the ADS and determine whether they are still accurate so a more robust analysis can be done to ascertain whether these units would still run as part of a simulation with increased amounts of DER penetration.

Entities should carefully plan and analyze the system for potential voltage profile issues with increased levels of DER. In some instances, distribution-level voltages may need to be actively controlled to maintain voltages within acceptable limits.

Further review of the DER_A dynamics model with frequency controls enabled should be done by Modeling and Validation Subcommittee to determine whether the observed oscillation is a model parameterization issue or an actual inter-area oscillatory mode issue.

Next Steps

Following are some recommendations for future analysis:

- Analyze additional power flow cases with higher than 20% DER on system and at various hours of the day to determine whether significant reliability issues become more prominent. If the study results indicate that the voltage profile becomes more variable, additional voltage controlling equipment to mitigate voltage profile shifts may be required.
- Analyze the effects of implementing more smart-inverter capability to see whether the DER itself can mitigate the voltage issues seen in the study.
- Perform analysis to see if co-optimization of distribution and transmission system would result in a more reliable system with increased penetration of DER.
- Test and validate the DER frequency response model. Further study of these models in the WECC system should be done to determine whether the observed oscillations are due to a model parameterization issue or an actual inter-area oscillatory mode issue.
- Future studies should be performed with frequency response enabled for DER and tuned to represent DER capabilities that are in IEEE 1547-2018 standard.
- Analyze the system in PCM for extreme loads, such as 1-in-20 load profiles, across the system along with increased electrification of transportation.

Contributors

We want to thank the following people and organizations for the hard work and time they have invested in this project:

Name	Organization
Amir Sajadi	WECC
Amy Mignella	Amy T. Mignella, Esq.
Brian Evans-Mongeon	Utility Services
Bryant Hicks	Salt River Project
Dan Kopin	Utility Services
Douglas Welsh	General Electric
Eric Baran	Western Interstate Energy Board
Gerald Harris	Quantum Planning Group
Irina Green	CAISO
James Zhang	IEEE
Jimmy Zhang	AESO
Jon Jensen	WECC
Layne Brown	WECC
Nick Hatton	WECC
Peter Mackin	GridBright
Richard Marrs	Quantum Planning Group
Spencer Tacke	Auriga Corp
Steve Ashbaker	WECC
Thomas Carr	Western Interstate Energy Board
Christopher Fecke Stoudt	Arizona Public Service
Chifong Thomas	Thomas Grid Advisor
Leo Bernier	Advanced Energy Solutions
Michael McMaster	Arizona Public Service

Appendix A—Additional Figures

2030 ADS PCM V2.2.1 vs 20% DER

The chart below compares the annual energy of the 2030 ADS PCM V2.2.1 and the 20% DER case.

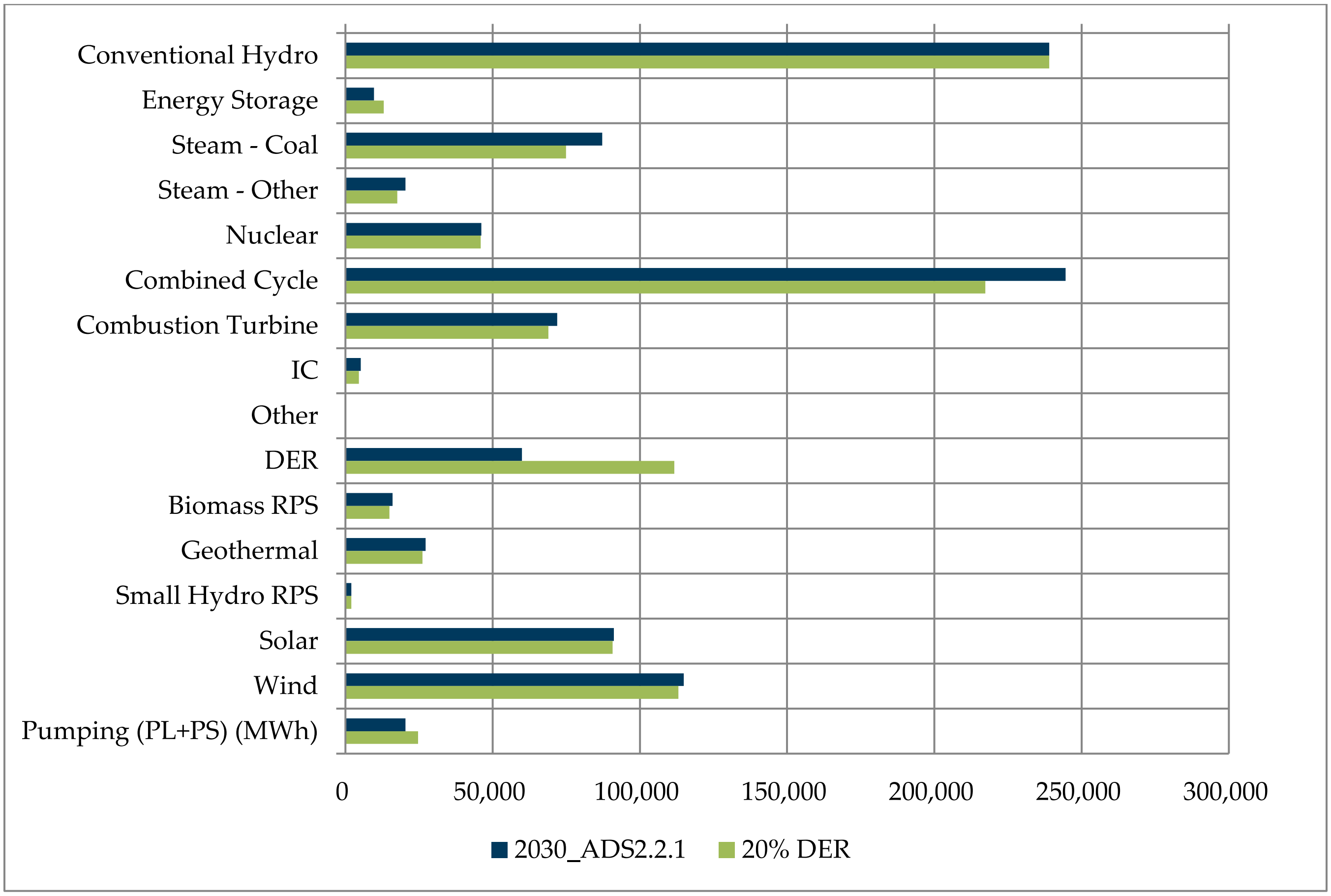

Figure A1: Annual generation (GWh)—2030 ADS PCM V2.2.1 vs. 20% DER

2030 ADS PCM V2.2.1 vs 35% DER

The chart below compares the annual energy of the 2030 ADS PCM V2.2.1 and the 35% DER case.

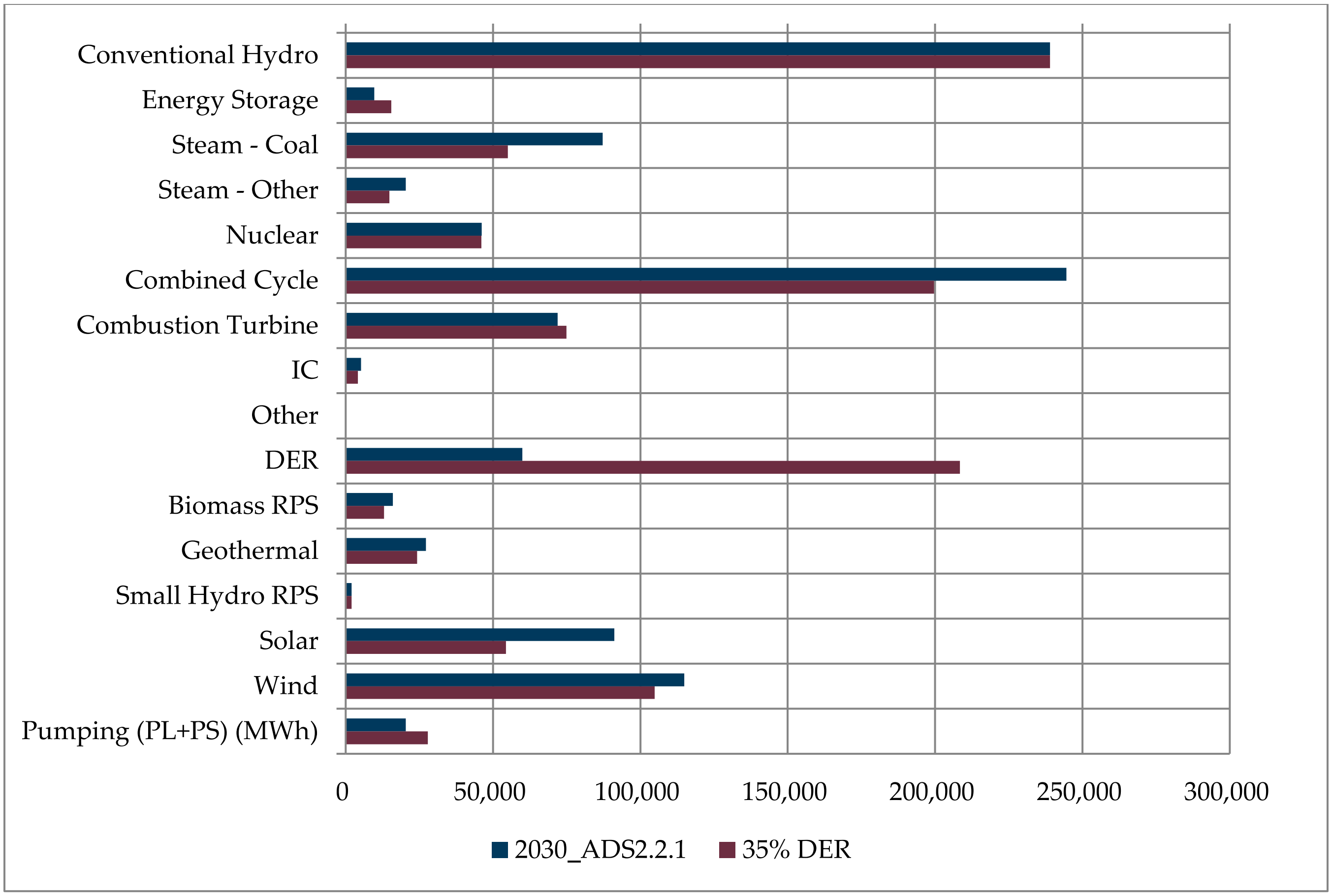

Figure A2: Annual generation (GWh)—2030 ADS PCM V2.2.1 vs. 35% DER

2030 ADS PCM V2.2.1 vs 35% DER Redistributed

The chart below compares the annual energy of the 2030 ADS PCM V2.2.1 and the 35% DER Redistributed case.

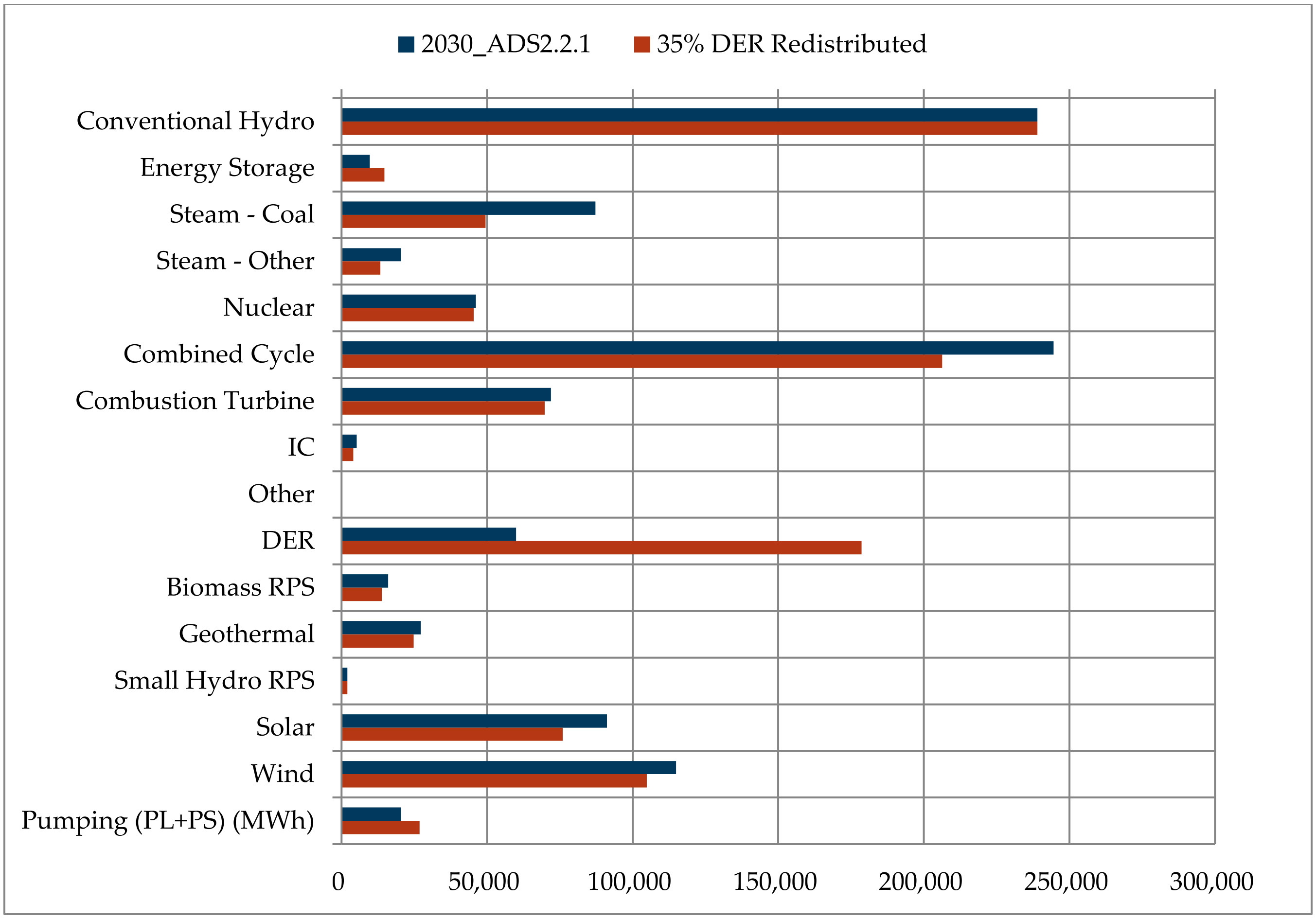

Figure A3: Annual generation (GWh)—2030 ADS PCM V2.2.1 vs. 35% DER Redistributed

2030 ADS PCM V2.2.1 vs 35% DER Redistributed 400MWx4hr

The chart below compares the annual energy of the 2030 ADS PCM V2.2.1 case and the 35% DER Redistributed 400MWx4hr case.

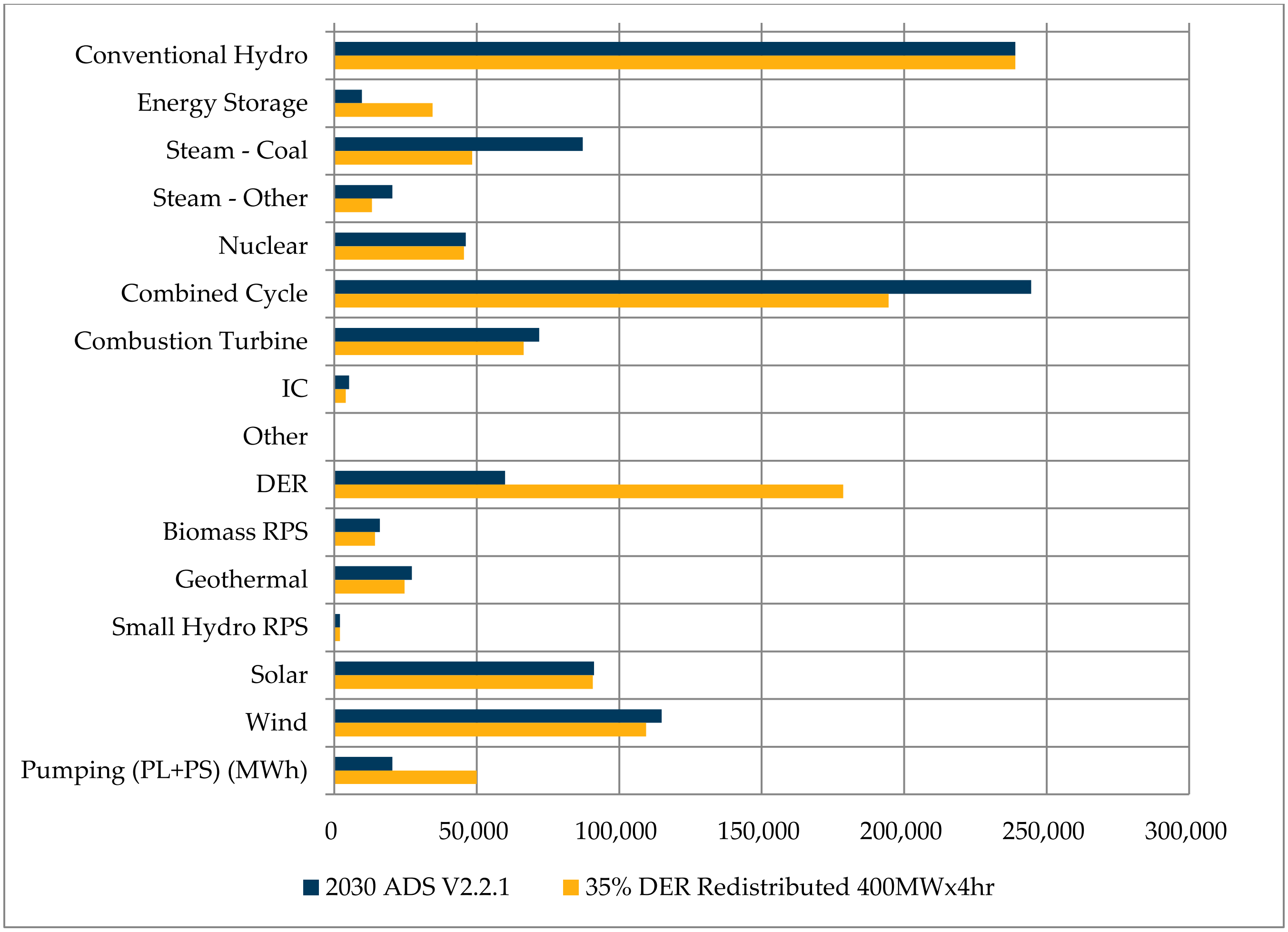

Figure A4: Annual generation (GWh)—2030 ADS PCM V2.2.1 vs. 35% DER Redistributed 400MWx4hr

35% DER Redistributed versus 35% DER Redistributed 400MWx4hr

The chart below compares the annual energy of the 35% DER Redistributed case and the 35% DER Redistributed 400MWx4hr case.

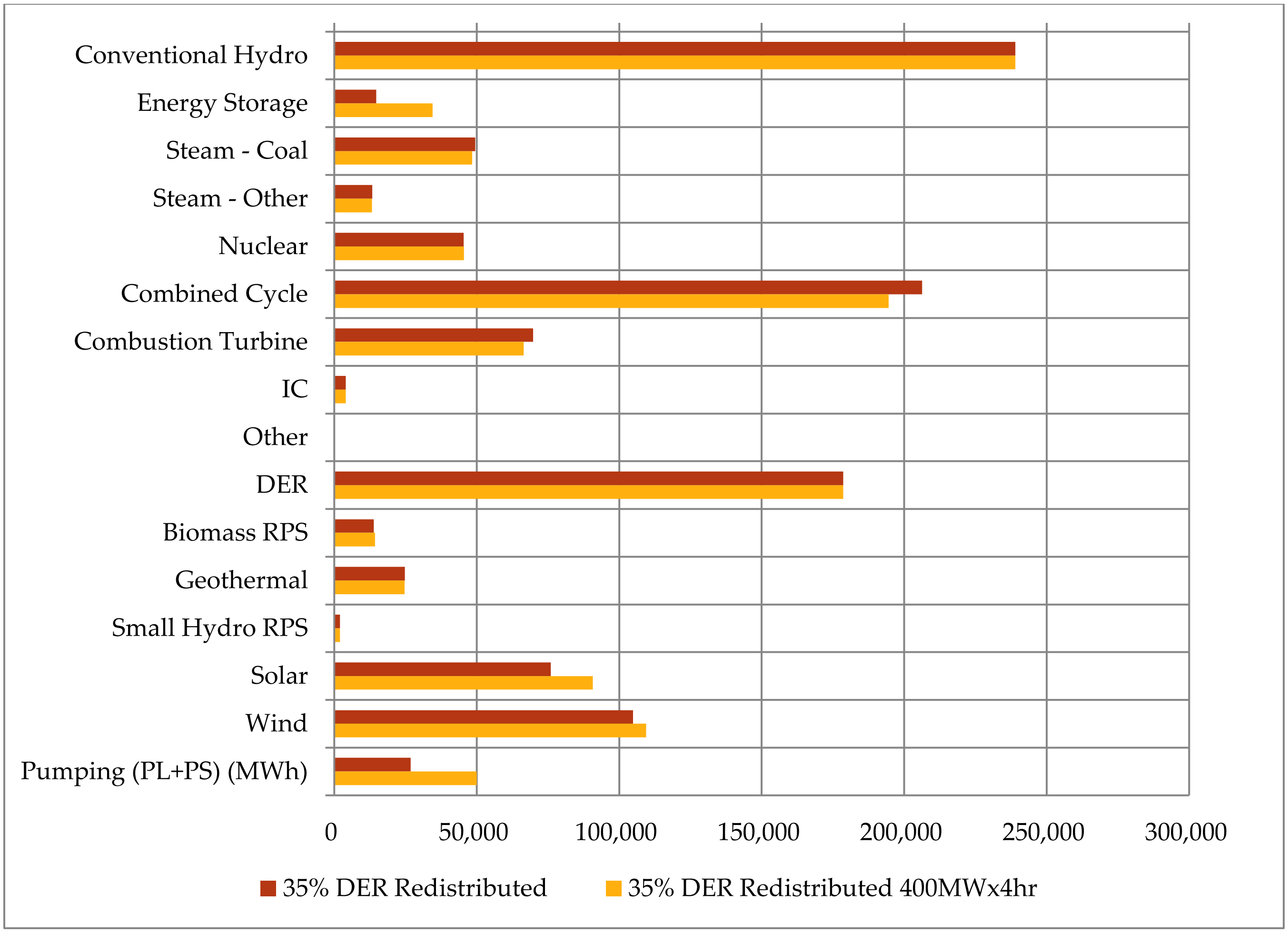

Figure A5: Annual generation (GWh)—35% DER Redistributed vs. 35% DER Redistributed 400MWx4hr

Appendix B—Standard Disturbances

Chief Joe Brake insertion—Insertion for 30 cycles, then removal of the large braking resistor in the Northwest.

Double Palo Verde outage—Simultaneous tripping of two Palo Verde generation units.

Colorado River–Red Bluff outage—Three-phase fault with tripping of two transmission lines in Southern California.

North Gila–Imperial Valley—Three-phase fault with tripping of one transmission line in Southern California.

Gates-Midway and Diablo–Midway outage—Three-phase fault with tripping of two transmission lines in Northern California.

Brownlee–Hells Canyon outage—Three-phase fault with tripping of one large transmission line in Idaho. This includes the approximation of an associated RAS which may drop generation if needed.

Daniel Park–Comanche outage—Three-phase fault and then tripping of two large transmission lines in Colorado.

Pacific DC Intertie (PDCI) block—Simulates a block (removal of the lines from service) of the DC line from Celilo (in the Northwest) to Sylmar (in Southern California). This is typically only simulated on cases with a flow from south to north on the PDCI. There is also a potential for generation drop as part of this disturbance—but that data was not available when this disturbance was run.