

Impact of High Distributed Energy Resources

Jon Jensen and Nick Hatton

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Executive Summary

This assessment analyzed the impact of high penetrations of Distributed Energy Resources (DER) on the Western Interconnection. The modeling approach for this analysis started with the 2030 Anchor Data Set (ADS) and added additional DER without replacing existing resources. DER in these assessments were assumed to be behind-the-meter (BTM[[1]](#footnote-2)) rooftop solar. The additional DER units were distributed by load areas and busses as a percentage of load at each bus. DER was specified as a “must take” resource with an hourly shape, which means that power generated from sun light is dispatched directly without regard to market prices and cannot be curtailed in the simulation. The study postulated increases in DER levels based on assumed increases of per capita DER levels for each state to investigate potential reliability issues. The amount of DER added for this study was not intended to represent a forecast of the future, but rather to assess how the bulk power system would behave with higher levels of DER.

We assessed the following cases representing various levels of DER penetration in the production cost model (PCM)[[2]](#footnote-3) for this assessment:

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

The 2030 ADS 20% DER case was also assessed in the power flow and stability analyses.

The initial starting case (2030 ADS PCM V2.2.1) specifies that California has the largest amount of DER capacity among western states. Per capita, however, California and Arizona both have the highest DER per capita of about 0.5 MW per 1,000 people. California has a larger population than the other states and provinces in the West, therefore DER impacts are more pronounced in California.

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 in part due to the modeling assumption that DER could not be curtailed. We also saw that for all studied cases, some thermal units remained on due to system ramping requirements, must run assignments, and unit commitments for other times of the day.

In general, reduction of thermal generation output was observed 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/DER production drops off at the end of the day.

Adding battery storage to the high DER case served to decrease curtailment of the solar and wind generation. During the daylight hours, surplus wind and solar generation charged the batteries for use in later hours of the day rather than curtailing it.

Another interesting observation concerned the impact of high penetration of DER to locational marginal pricing (LMP). In the 35% DER case, LMPs became negative during daylight hours in some areas. Persistent negative prices could create challenges for efficient market operations. However, the addition of battery storage to the high DER case served to bring the average generation LMPs back to positive values. So, although high DER did offset thermal resources, there is a point at which it may affect the market.

The increase in DER also affected some path flows. There were more paths that had a reversal of flows in high DER cases when compared to the 2030 ADS PCM V2.2.1. For example, Path 66 (California – Oregon Intertie) flows reversed to south to north more frequently in the high DER cases as compared to the 2030 ADS PCM V2.2.1.

Observations

PCM

* Transmission use (magnitude and direction) changed as more DER was placed on the system.
* DER did not displace all thermal generation during the daytime; some thermal units remained on-line for operational or reliability requirements.
* Negative LMPs were observed in the 35% DER cases
* Large amounts of commercial solar and wind curtailments were observed in the 35% DER cases
* Thermal units saw reduced energy output in all cases with high DER penetration as compared to 2030 ADS PCM V2.2.1
* Many effects from high DER are more pronounced in California due to the assumed DER penetration levels

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 then 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 therefore resulted in decreased load loss.
* Under disturbance conditions, undamped oscillations were observed for DER when frequency controls were enabled

Recommendations

Monitor and analyze the system with increasing levels of DER for potential negative LMPs, curtailments and unexpected increased use of CTs.

It is essential that utilities collect data on DER (how much and where) so that they can analyze the system in planning and operations studies.

Carefully review generation units labeled as Must Run. 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 Anchor Data Set and determine if they are still accurate so that a more robust analysis could be done to ascertain whether these units would still run as part of simulation with increased amounts of DER penetration.

Perform additional studies, especially of other seasons and hours of the day should be done in power flow and dynamics analysis. Additional studies of other seasons and hours of the day should be performed to ascertain whether the voltage profiles are consistently shifting higher for those times, or if the voltage profiles will instead swing low in other times of the day and for other seasons due to lack of voltage support from the DER when it is offline. If the study results indicate that the voltage profile will become more variable, additional voltage support to mitigate these voltage profile shifts may be required.

Further review of the DER\_A dynamics model with frequency controls enabled should be done to determine if the observed oscillation is a model parameterization issue, an inter-area oscillatory mode issue, or some other concern that should be resolved.

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# Purpose

The purpose of the Impact of High Distributed Energy Resources (DER) study is to identify potential reliability risks to the Bulk Power System (BPS) in the Western Interconnection resulting from high levels of DER penetration on the system. This study added DER on the system without replacing any existing resources. The DER in this assessment was 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—

* Generation mix;
* Transmission flows;
* Locational Marginal Pricing (LMP);
* Frequency response;
* Transient voltage recovery;
* Potential transmission congestion;
* Power flow steady state, transient stability;
* Dynamic disturbances; and
* Potential impact to WECC path capacity and utilization in the year-10 horizon.

## 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 transmission 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, and when does DER become a reliability concern?
* How might DER dispatch affect reliability?
* How does a significant increase in DER impact 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

We assessed the following cases for this assessment:

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

The 2030 ADS 20% DER case was assessed in the power flow and dynamics.

## DER Assumptions

For all cases, DER—

* Was considered BTM rooftop solar modeled on the generation side;
* Was modeled as a “must take” resource; This does not allow the DER to be curtailed or spilled, it must be used when generated;
* Follows the solar generation profile shapes for its area;
* Levels studied in this assessment were based on per capita DER levels observed in high adoption areas (California and Arizona) and applied to other areas in the Western Interconnection
* Was 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[[3]](#footnote-4) optimized battery charging and discharging based on production cost during simulation runs
* The same amount of battery storage was placed in each area. An equal amount of battery storage was distributed within each area as a percentage of the area’s load at each bus.
* DER was modeled as distributed generation (DG) in the load models in the power flow base cases; and
* IEEE-1547-2003 based dynamics models were used to represent the capabilities of the DER in transient stability studies.
* Load demand was not adjusted in the PCM. DER were modeled as generators.

## Limitations of the DER study:

* There was no transmission expansion allowed in this study; 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 V2.2.1) | * Starting and comparison case * 9% of installed generation capacity is DER |
| 20% DER Case  (20% DER) | * Started with the 2030 ADS PCM V2.2.1 case * Increased DER capacity to about 20% |
| 20% DER Power Flow and Dynamics Case  (20% DER PF) | * Similar to the 20% DER PCM case above * DER capacity was added to the case to represent the same percentage of DER capacity as the PCM case. |
| 35% DER Case  (35% DER) | * Started with the 2030 ADS PCM V2.2.1 case * Increased DER capacity to about 35% |
| 35% DER Redistributed 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 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” |

# 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 in the cases was meant to represent aggressive adoptions of DER in the form of BTM rooftop solar.

Batteries were also added to reveal the impacts of battery storage in conjunction with high DER penetrations.

The power flow and dynamics cases were built on the 2030 Heavy Summer 1 base case. This was the reference case imported into the 2030 ADS.

# 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 i.e. 0.54 MW/1000 people. This 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/1000 people per capita capacity. Then California and Arizona DER per capita capacity was increased beyond 0.54 MW/1000 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/1000 people per capita capacity—adopting another 50% DER capacity (0.81 MW/1000 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/1000 people per capita capacity, then increased by 150% compared to the 2030 ADS PCM case for a DER capacity of (0.81 MW/1000 people), except for California and Arizona, which we increased by 300% compared to the 2030 ADS PCM case for a DER capacity of (1.62) MW/1000 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% Redistributed DER case has the same amount of DER as the 35% DER case. However, since most of the DER ended up 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 - 5 show the DER capacity and distribution.

States other than California had much lower amounts of DER capacity, or even none, 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 Authorities for the most part, with a few exceptions. Batteries were added to 38 areas in the case. Battery storage additions for each area include 400 MW capacity for four hours, i.e., 1,600 MWh per area for 38 areas. This totaled 15,200 MW capacity and 60,800 MWh battery storage. The battery distribution is shown in Figures 1 and 2.

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

Figure 2: Estimated population by state or area

Figure 3 shows total DER capacity in the cases.

Figure 3: DER capacity by case

Figure 4 shows the DER capacities by region

Figure 4: DER Capacity by region

Figure 5 shows the DER capacities by state or province

Figure 5: DER capacity by state or province

Below are the DER installed capacities per case:

* 2030 ADS 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 shows the battery capacity by state for the ADS V2.2.1 versus 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.
2. The second case was a modified version of the 2030 HS1a1. The DER data from August 18th 2030 1:00 pm Mountain Time in the 2030 ADS PCM 20% DER 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 second case had approximately 39,718 MW of DER with the same amount of load. 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. Use of these models resulted in DER oscillations as described in section ‘Findings and Conclusions - Dynamics’. Therefore, it was determined that it would be simpler to use models based on the IEEE-1547-2003 standard[[4]](#footnote-5) which did not show oscillations during simulation. Subsequently, three different variations of dynamics datasets were developed for DER to represent diversity of DER capability. The first dynamic dataset that was used was the IEEE-1547-2003 model as parameterized in the NERC DER A parameterization guideline[[5]](#footnote-6) and was simulated in both the original 2030HS1a1 and the second case. The other two variations of the dynamics models were developed to explore potential differences in inverter technology. The second model, with parameter Vrfrac set to 1, was intended to represent more advanced panels capable of returning to service quickly after severe voltage dip. The third model was updated to include active voltage controls that should respond to voltage deviations in the system. These active voltage controls could be included in smart inverters in the future. Most inverters in service as of writing of this report, do not have this capability. Simulations were then performed with the standard disturbances which are listed in Appendix-B to analyze the effects of increased DER penetration to the Western Interconnection dynamic system response.

# Findings and Conclusions

## Annual Energy

Increased DER penetration led to California ending up with the most DER capacity, much more than the other states. Some states did not have any DER in the foundational case.

Figure 7 shows the percentage of annual energy that was supplied by DER. Even though the foundational ADS V2.2.1 case had about 9% of its generation capacity made up of DER, DER only made up about 6% of the total annual energy due to DER generating power during the daylight hours.

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

Although the 35% DER Redistributed case has the same DER capacity as the 35% DER case, the capacity factors of the DER in different regions of the Western Interconnection, resulted in different DER energy output. For example, capacity factors for DER in Southern California are higher than the Pacific Northwest.

Figure 8 shows the annual energy by technology type for each case. Hydro and nuclear energy output nearly stayed the same in all cases because they are modeled in the simulations as baseload units, while thermal and DER changed drastically.

Figure 8: Annual energy (MWh)

As DER is added to the cases, there are some annual energy trends that emerge:

The 20% DER case shows a decrease in coal, combined-cycle gas, and combustion turbine; and an increase in DER, which is to be expected. We also saw a decrease in commercial solar and wind outputs. This is due to curtailment/spillage of those resources because of high penetration of DER resulting in excess generation during the day.

The biggest annual energy differences are shown below in in Figure 9.

Figure 9: Largest Annual Energy Differences Between Study Cases

### 2030 ADS V2.2.1 versus 20% DER

Figure 10 represents annual energy change between the 2030 ADS V2.2.1 and 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. We noticed in many areas increased curtailment of commercial solar and wind due to the higher penetrations of DER.

Figure 10: Annual generation change (GWh)—ADS 2.2.1 vs. 20% DER

### 2030 ADS V2.2.1 versus 35% DER

The 35% DER case shows bigger differences in energy production as compared to 2030 ADS V2.2.1. Figure-11 shows more energy production from DER, bigger decreases in coal energy and combined-cycle gas, with more curtailment of commercial 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: solar DER production drops off at the end of the day and combustion turbine gas generation provides the necessary ramping capability to meet demand. Most of the increase in combustion turbine was in California; the second largest increase was observed in Colorado.

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

Figure 11: Annual generation change (GWh)—2030 ADS 2.2.1 vs. 35% DER

### 2030 ADS V2.2.1 versus 35% DER Redistributed

The 35% DER Redistributed case is very similar to the 35% DER case. However, energy from DER is decreased since some of the California DER has been distributed to other areas, many with less solar output than what California would have had. This results in less energy from DER compared to the regular 35% DER case.

Figure 12 shows less DER increase in the 35% DER Redistributed case than in the 35% DER case. Additionally, there is less curtailment of commercial wind and solar.

Figure 12: Annual generation change (GWh)—2030 ADS 2.2.1 vs. 35% DER Redistributed

### 2030 ADS V2.2.1 versus 35% DER Redistributed 400MWx4hr

We added batteries to the study to augment the grid-level batteries to see how that affected the system with higher levels of DER.

The 35% DER Redistributed 400MWx4hr case for each area allows for extra energy throughout the day from renewables (solar and wind) to be stored and used later. Figure 13 shows that this case does not curtail nearly as much solar and wind as the other cases due to battery charging. We also saw a greater decreases in energy from thermal units since the charged batteries were able to help serve the evening load, relieving some of the strain on thermal generation to provide energy after the daylight hours when DER energy is not available.

Figure 13 shows the increase in DER, but it also shows that not as much commercial solar and wind is being curtailed because it is being stored in the batteries and used later. This shows how batteries can decrease curtailments.

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

Overall, the high levels of DER resulted in a decrease in thermal generation output and an increase in commercial solar and wind curtailment during the day since the DER could not be curtailed. This case also showed that even with high DER levels, some thermal units remained on due to ramping requirements, must run assignments, and unit commitments for other times of the day. Even in the 35% DER case, there are thermal units that remain on during the day.

Figure 14 shows energy spillage for each case. The cases with the most DER resulted in most spillage of commercial wind and solar generation. As DER were distributed to areas outside of California, or as batteries were added, the system is able to use that energy more efficiently, either through energy storage, or dispersing the energy, rather than being forced to curtail.

Figure 14: Annual Energy Spillage

## Coal Offset

DER penetrations also played a role in how coal units were dispatched in the simulations. Overall, coal units were dispatched less and spent more time at zero output with high penetrations of DER. Figure 15 shows percentage of all the hours that the coal units were dispatched. In general, coal unit dispatch hours decrease as DER capacity increases.

Figure 15: Percentage of hours coal units are dispatched

Figure 16 represents the coal unit dispatch 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 hours of coal units by area

## Summer Day

Figures 17 and 18 show average summer day curtailment of wind and solar generation at different DER levels. In general, the more DER added, the more curtailment of solar and wind resources occurred because DER is not allowed to curtail in our assessment.

Figure 17: August 18, 2030, wind curtailment

Figure 18: August 18, 2030, solar curtailment

Figure 19 represents the same hour (August 18, 2030 1:00 PM Mountain Time) for each case. These figures show 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 and is able to use that energy to charge the batteries.

Figure 19: August 18, 2030, hour 13

Figure 20 shows percentage of DER energy during the same hour, (hour 5509, August 18, 2030, 1:00 pm). This is a mid-day hour showing how much DER contributes to the generation mix mid-day.

Figure 20: Energy DER-ratio DER/total gen; hour 5509

Looking at the same day but an evening hour (August 18, 2030, 8:00 PM), we see that DER cannot contribute very much to this evening hour. However, in the case with battery storage (35% DER Redistributed 400MWx4hr), the batteries that were charged during the day by renewable, are now able to discharge and contribute to the load demand in the evening. As shown in Figure 21 for the 35% DER Redistributed 400MWx4hr bar graph, batteries offset thermal generation in the evening.

Figure 21: August 18, 2030, hour 20

## Gas Generation Ramping

Gas generation ramping was much steeper in the evening ramp when high levels of DER were added to the cases. Due to the flexibility of gas generation, the gas generating units were able to help make up the generation deficit as DER generation levels dropped off at the end of the day. However, the gas ramping in the evening isn’t as steep in the case where batteries were added because the batteries were able to discharge during the evening ramp making it less steep.

Figure 22 shows only gas generation for the following technology types: Gas-CC, Gas-Cogen. Gas-CT, Gas-ICE, 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 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

Figures 24 & 25 show the gas generation ramping for CAISO only. The following technology types were included in the chart below: Gas-CC, Gas-Cogen. Gas-CT, Gas-ICE, Gas-Steam.

The ramping in California alone is steeper than the aggregated interconnection-wide ramping seen in Figures 22 & 23. This is due to much higher DER penetration in California as compared to the rest of the interconnection. The gas ramping in the evening isn’t as steep in the case where batteries were 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 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

## Market Impacts

If there is a large excess of renewable energy at certain times of the day, this can cause market situations that may need further examination. Figure 26 shows that the 35% DER case causes LMPs to be negative for many of the 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 market impacts if large amounts of renewables are added to the system without other considerations included to help resolve some of the impacts to the energy markets. A careful examination of current market structures will be necessary to bring the policy objectives of high DER penetration to fruition. These considerations could include market/rate design, management systems of resources, addition of battery storage or hybrid (e.g. solar/wind plus battery) systems.

Figure 26: Average LMP for generators ($/MWh).

## Transmission Flows

Certain DER penetrations affected transmission flows differently. Figures 27-36 show that the in the 2030 ADS V2.2.1 case, most of the time the Pacific DC Intertie (PDCI) and California – Oregon Intertie (COI) are flowing into California. However, as we add more and more DER to California, power is forced out of California causing a reverse of flow on those paths more often. For example, 35% DER case caused the California – Oregon Intertie to flow south to north about half the time instead of primarily flowing north to south in the 2030 ADS PCM V2.2.1 case.

However, when we distributed some of the DER out of California, we saw a decrease in reverse of path flows on the PDCI and COI.

### Pacific DC Intertie (PDCI)

Figure 27: ADS V2.2.1 9% DER PCDI

Flow North to South

Figure 28: 20% DER PCDI

Flow South to North

Flow North to South

Figure 29: 35% DER PDCI

Flow South to North

Flow North to South

Figure 30: 35% DER Redistributed PDCI

Flow North to South

Flow South to North

Figure 31: 35% DER Redistributed 400MWx4hr PDCI

Flow South to North

Flow North to South

### California Oregon Intertie (COI)

Figure 32: ADS V2.2.1 9% DER COI

Flow South to North

Flow North to South

Figure 33: 20% DER COI

Flow South to North

Flow North to South

Figure 34: 35% DER COI

Flow North to South

Flow South to North

Figure 35: 35% DER Redistributed COI

Figure 36: 35% DER Redistributed 400MWx4hr COI

## Power Flow and Dynamics

The power flow hour represented hour 5509, August 18, hour 13 (1:00 p.m. MST) from the 2030 ADS PCM 20% DER PCM case. The rationale was to represent an hour that entailed high DER output compared to total generation. This hour represents a period when 20% of online generation output is from DER.

The Figure 28 shows the total generation compared to the DER/Generation Ratio for the week of August 13, 2030 – August 19, 2030. The star represents hour 5509, August 18, hour 13 (1:00 PM).

Figure 28: Generation vs DER/total gen ratio; August 18, 2030 (MW)

The Figure 29 shows the total generation compared to the DER/Generation Ratio for the day. The star represents hour 5509, August 18, hour 13 (1:00 PM MST).

Figure 29: Generation vs DER/total gen ratio; August 18, 2030 (MW)

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

Figure 30: Buses with a greater than 5% increase in voltage

A post transient analysis was conducted on both cases. A post transient analysis is a power flow analysis representing steady state conditions after a disturbance. 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 post transient condition, no bus voltage shifted more than 10% in HS1a1 and 20% DER PF case. All buses whose voltage shifted by more than 5% in the original case also shifted by more than 5% in the 20% DER PF case. An additional 137 buses shifted by more than 5% in the 20% DER PF case. A comparison of the resulting generator dispatch amounts was done and can be seen below in Figure 30.

Figure 31: Generation Redispatch by area

Areas with a large increase in DER saw a decrease in generation redispatch, while Areas with a relatively small increase in DER saw their dispatch increase as their dispatchable units made up a greater proportion of the response.

## Dynamics

Standard disturbances as listed in Appendix-B were simulated in the 20% DER case. The following case combinations were tested:

* 2030 HS1a1 PF with IEEE-1547-2003 DER models as a baseline
* 2030 HS1a1 PF Updated with 40 GW of DER and IEEE-1547-2003 DER models
* 2030 HS1a1 PF Updated with 40 GW of DER and IEEE-1547-2003 DER models with the Vrfrac parameter set to 1.
* 2030 HS1a1 PF Updated with 40 GW of DER and IEEE-1547-2003 DER models with dynamic voltage controls enabled

Originally the intent was to use more forward-looking models that were CA Rule 21 and/or IEEE-1547-2018 compliant. Oscillations observed with these models lead us to revert back to an older dataset that would allow to us gather data on how most modern DER might operate. Whether these oscillations were due to an Inter-Area Oscillatory mode being activated by large amounts of load dropping, an artifact of the DER all having the same model, or some combination of the two was not determined. An example of this oscillation is shown below in Figure 32.

Figure 32: DG power at bus 30941 on the Diablo-Midway outage

Several metrics were used to evaluate system performance for these simulations. The first is how much load was shed by the composite load model. The composite load model was developed by the Modeling and Validation Subcommittee (MVS) to represent the approximate behavior of loads in the system. Depending on the climate and feeder type the load is assigned certain parameters. Part of these parameters is a voltage dependency. The model trips a percentage of the load based on voltage and time. If the voltage at the transmission level bus drops below a certain threshold for a certain amount of time some of the load is tripped. Depending on the model, some or all of that load may return after a certain amount of time as well. 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 due to low voltages during the disturbance simulations can be seen below in Figure 33.

Figure 33: Load shed due to voltage in the composite load model

The Diablo-Midway outage showed increased load loss when the DER was added to the system, while the Colorado River-Redbluff outage showed a significant decrease in load lost when DER was added to the system. In both cases, upon closer examination, it was seen that these differences were attributable to timing differences in the simulation.

Figure-34 shows the voltage plot for one load for Diablo-Midway outage simulation. The voltage dips lower in the cases with DER, but it returns above the tripping threshold at almost exactly the same time as in the original case. However, the second dip during the recovery for the load with DER is low enough to be below the undervoltage tripping threshold for the Motor-A component of the composite load mode. This causes an additional amount of the Motor-A component to be tripped in the cases with DER.

Figure 34: Bus 30941 load voltage during Diablo-Midway outage

Figure-35 shows the voltage for a load during the Colorado River – Redbluff outage. The trace with the slow recovery is 2030 HS1a. The recovery time is slow enough that the Motor-D component of the load enters into a stall, which leads to the slow recovery. The voltage only recovers when all of the Motor-D components trip. The cases with DG dip below the stall threshold a little bit later, and initially recover above the stall threshold at the same time as the original case. The Motor-D components do not enter stall, and so the voltage recovers quickly, and the load is not lost. This can be seen more clearly in Figure-36.

Figure 35: Bus 24229 voltage during Colorado River-Redbluff outage

Figure 36: Bus 24229 voltage during Colorado River-Redbluff outage

Frequency is the second metric used to evaluate system performance in this study. Frequency during these outages did not descend low enough to trigger under-frequency load shedding. Below is the Colorado River – Redbluff Outage frequency. The frequency in the 2030 HS1a increases greatly. This is due to the load shed in that event. Relatively little load sheds in the 20% DER versions of the case so a similar response is not seen. A small swing down in the initial frequency is seen, this could be due to temporary shifts in load and generation as the disturbance propagates out toward the bus where frequency was measured.

Figure 37: Frequency response during the Colorado River - Redbluff Outage

All of the Diablo-Midway cases exhibit load shed – so as a result the frequency increases in all of these cases as seen below.

Figure 38: Frequency response during the Diablo - Midway Outage

The Double Palo Verde outage is a loss of 2700 MW of generation. In these cases, there was no load lost in this outage as the voltages and frequency did not drop low enough to trigger it. The plot below shows that all the cases with DER followed the same, lower trace. The DER did not have frequency responsive controls enabled, so the smaller pool of synchronous generation took longer to pick up the system frequency. The system here still did not approach a low enough level to trigger under-frequency load shedding.

Figure 39: Malin 500 frequency response during the Double Palo Verde outage

Another metric that was used to evaluate system performance is the Interconnection Frequency Response as calculated in MW/.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/.10 Hz. A decline in frequency response was observed in the cases with 20% DER, where frequency response was 1578 MW/.10 Hz. A decline was expected due to lack of frequency response from DER. Future studies could be performed with frequency response enabled and tuned to represent capabilities that are in newer standards. However, unless those inverters were required to operate with headroom, they would still not be able to contribute to the frequency response when generators were tripped. A frequency response of 1578 MW/.10 Hz is still well above the [NERC recommended IFRO](https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2020%20FRAA%20Report_packaged.pdf) of 858 MW/.10 Hz for the Western Interconnection.

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.

# Observations and Recommendations

As we consider this study, we reflect on the purpose of this assessment, which was to study the impact of high DER, and to identify potential reliability risk to the BPS in the Western Interconnection.

This study set out to answer the following 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, and when does DER become a reliability concern?
* PCM—How is DER dispatched?
* Power flow—How does DER dynamically respond to contingencies?

## Conclusion

This study showed the different effects of adding DER to the system, and how DER can offset coal and other thermal units. Adding batteries can bring even more potential to DER and other renewables by contributing to the evening ramp. It can contribute to positive market impacts, but it can also contribute to negative market impacts.

Our overall conclusion is that by carefully adding DER to the system (the right amount in the right areas) will create positive effects, in a way that can improve system reliability. Conversely, if DER is added unwisely (concentrated in limited areas without the ability for economic power trading), then DER expansion can lead to market failures.

More time to develop additional power flow cases would have been very beneficial. The conclusions that can be drawn here are based on a single increase in DER. Larger increases might make any effects of the DER more pronounced.

Shifts in voltage profiles were seen as DER was added to the system. These shifts were mostly an increase in voltage. However, some decreases were seen as equipment output shifted to compensate for these increases. Additional study, especially of other seasons and hours, should be done with this system. Only testing with the DER in service was done. More testing of a later hour with the DER off-line may reveal system issues that should be evaluated. Significant increases in DER may call for more voltage support to mitigate these shifts in voltage profiles.

The dynamics models that are currently used for the DER exhibited oscillatory behavior with frequency controls enabled. Further study of these models in the WECC system should be done to determine whether this is a parameterization issue, an inter-area oscillatory mode issue, or something else that should be resolved.

The system response seen with the added DER was not linear regarding load loss. This may be due to the sensitivity of the model – significant differences in load loss were observed that appeared to be caused by relatively small-time differences. In some cases, increased DER seemed to lead to more voltage issues, which led to load loss. In other cases, the presence of DER seemed protective against load loss. More cases should be developed and studied to see whether there are any system-wide conclusions to be drawn.

|  |  |  |  |
| --- | --- | --- | --- |
|  | Reliability Implications | | |
| **Scenario** | **Resource Adequacy** | **Changing Resource Mix** | **Distribution system and customer load impacts on the transmission system** |
| 2030 ADS PCM V2.2.1 | No verified unserved load | Year 10 future | None identified |
| 20% DER Case | No verified unserved load | Gas units must be able to ramp a little higher and a little faster.  Very little added curtailment to commercial solar and wind.  Noticeable decrease in thermal production. | No major impact |
| 20% DER Power Flow and Dynamics Case | Load and Generation balance was met. Frequency response was adequate | Frequency response was adequate. UFLS tripping threshold was not passed. | Voltage profiles shifted, in some cases significantly. Presence of DER affected load loss due to voltage during dynamics tests. |
| 35% DER Case | No verified unserved load | Gas units must be able to ramp much higher and much faster  Curtailment of commercial solar and wind has drastically increased  Drastic decrease in thermal generation, except combustion turbine gas, which has increased due to the need for flexibility of resources in evening ramp | The average price of electricity is extremely negative due to the excess generation in the day |
| 35% DER Redistributed Case | No verified unserved load | Gas units must be able to ramp much higher and much faster  Curtailment of commercial solar and wind has quite a bit, but not as much as the 35% DER case  Drastic decrease in thermal generation | The average price of electricity is negative due to the excess generation in the day, but not as much as the 35% DER case. |
| 35% DER Redistributed Case with 400MWx4hr battery storage | No verified unserved load | Increase in energy storage  Gas ramping requirements are similar to 2030 ADS V2.2.1  Commercial solar and wind are curtailed, but amount is decreased compared to the 35% DER and 35% Redistributed cases  Drastic decrease in thermal generation | No major impact |

## Observations

Some observations that came from this study:

### PCM

* Transmission use (magnitude and direction) changed as more DER was placed on the system.
* DER did not displace all thermal generation during the daytime; some thermal units remained on-line for operational or reliability requirements.
* Negative LMPs were observed in the 35% DER cases
* Large amounts of commercial solar and wind curtailments were observed in the 35% DER cases
* Thermal units saw reduced energy output in all cases with high DER penetration as compared to 2030 ADS PCM V2.2.1
* Many effects from high DER are more pronounced in California due to the assumed DER penetration levels

### 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 then 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 therefore resulted in decreased load loss.
* Under disturbance conditions, undamped oscillations were observed for DER when frequency controls were enabled

## Recommendations

Monitor and analyze the system with increasing levels of DER for potential negative LMPs, curtailments and unexpected increased use of CTs.

It is essential that utilities collect data on DER (how much and where) so that they can analyze the system in planning and operations studies.

Carefully review generation units labeled as Must Run. 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 Anchor Data Set and determine if they are still accurate so that a more robust analysis could be done to ascertain whether these units would still run as part of simulation with increased amounts of DER penetration.

Perform additional studies, especially of other seasons and hours of the day should be done in power flow and dynamics analysis. Additional studies of other seasons and hours of the day should be performed to ascertain whether the voltage profiles are consistently shifting higher for those times, or if the voltage profiles will instead swing low in other times of the day and for other seasons due to lack of voltage support from the DER when it is offline. If the study results indicate that the voltage profile will become more variable, additional voltage support to mitigate these voltage profile shifts may be required.

Further review of the DER\_A dynamics model with frequency controls enabled should be done to determine if the observed oscillation is a model parameterization issue, an inter-area oscillatory mode issue, or some other concern that should be resolved.

## Next Steps

* Analyze a 35% DER power flow case or similar to find the threshold of DER on system
* Analyze the effect of implementing more smart inverter capability to see mitigation approaches
* Study how the Distribution system affects Transmission system
  + Study optimization of distribution system (capabilities, designs, management systems) to see effects on the transmission system
* Test and validate the DER frequency response model

# Contributors

We want to thank the following people and organizations for the hard work and time they 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 |
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| 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 vs 20% DER

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

## 2030 ADS vs 35% DER

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

## 2030 ADS vs 35% DER Redistributed

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

## 2030 ADS vs 35% DER Redistributed 400MWx4hr

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

## 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.

# Appendix B—Standard Disturbances

The Standard Disturbances are:

* Chief Joe Brake insertion;
  + Insertion for 30 cycles and 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;
  + 3-phase fault with tripping of two transmission lines in Southern California;
* North Gila – Imperial Valley
  + 3-phase fault with tripping of one transmission line in Southern California;
* Gates-Midway and Diablo-Midway outage;
  + 3-phase fault with tripping of two transmission lines in Northern California;
* Brownlee - Hells Canyon outage;
  + 3-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;
  + 3-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.

WECC receives data used in its analyses from a wide variety of sources. WECC strives to source its data from reliable entities and undertakes reasonable efforts to validate the accuracy of the data used. WECC believes the data contained herein and used in its analyses is accurate and reliable. However, WECC disclaims any and all representations, guarantees, warranties, and liability for the information contained herein and any use thereof. Persons who use and rely on the information contained herein do so at their own risk.

1. BTM (Behind the Meter) – The term “behind-the-meter” refers to energy production and storage systems that directly supply homes and buildings with electricity. [Residential](https://www.bostonsolar.us/residential-solar/) and [commercial solar panels](https://www.bostonsolar.us/commercial-solar/) are considered to be behind-the-meter, as are residential and commercial [solar batteries](https://www.bostonsolar.us/residential-solar/battery-storage/)—the energy that is produced and/or stored by these systems is separate from the grid and does not need to be counted by a meter before being used, so they are positioned behind the meter.

   https://www.bostonsolar.us/solar-blog-resource-center/blog/what-does-behind-the-meter-mean/ [↑](#footnote-ref-2)
2. PCM – Production Cost Model or economic dispatch model. Used to model the power system by minimizing costs as well as obeying the operating constraints of the system. [↑](#footnote-ref-3)
3. GridView – 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. [↑](#footnote-ref-4)
4. The IEEE 1547-2003 standard can be found at https://standards.ieee.org/standard/1547-2003.html [↑](#footnote-ref-5)
5. The NERC DER\_A Parametrization guideline can be found at https://www.nerc.com/comm/PC\_Reliability\_Guidelines\_DL/Reliability\_Guideline\_DER\_A\_Parameterization.pdf [↑](#footnote-ref-6)