WECC

Reliability Impacts of Most Likely Year 10 Future

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Executive Summary

This assessment, performed by the Year 10 Task Force (Y10TF), provides a baseline for the other assessments created in 2019. It is intended to reflect the reliability risks in the 2028 Anchor Data Set (ADS) Phase I data. The 2028 ADS includes both a power flow and a dynamics case, which is named the 2028 Heavy Summer 1a (28HS1a), and a Production Cost Model (PCM) case.

2028 ADS Power Flow and Dynamics

The standard disturbances and post transient analysis typically performed on a WECC base case when it is created were applied to the 28HS1a case to establish a base line for reliability risks present in the power flow and dynamics models. The assessment examined several metrics, including system instability, insufficient voltage support, and insufficient system response due to loss of generation.

2028 ADS PCM

The referenced power flow case (28HS1a) was imported into the PCM tool to provide the topology and generation resources for a security constrained economic simulation. The assessment used the results from the hourly PCM simulation for all hours of 2028 to review several reliability metrics, including unserved load, transmission congestion, and curtailed generation.

1. Introduction

The purpose of the Most Likely Year Ten Future Task Force (Y10TF) is to assess potential reliability risks associated with system resource adequacy, transient stability concerns, and congested path flows in the year-10 horizon. This assessment is intended to be a baseline for the other assessments in the 2019 study program. As a baseline this assessment identifies the potential risks with system conditions and resources as represented in the 2028 Anchor Data Set. As others perform other assessments it is possible other reliability concerns could be identified with different resources and system conditions from the baseline. The Anchor Data Set (ADS) is a new process intended to more closely align the submitted and projected 10-year planning horizon models of the transmission planning and resource planning organizations from the Western Regions and other organizations within the Western Interconnection.

2. Participants

Participants in the Y10TF:

- Shilpa Toppo - Chair
- Frank Afranji
- Ravi Aggarwal
- Jamie Austin
- Hassan Baklou
- Shannon Black
- Angela Bond-Simpson
- Lindsay Briggs
- Tyler Cooper
- Taylor Cramer
- David Franklin
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WECC Staff who participated:

- Camille Duncan
- Nick Hatton
- Stan Holland
- Dick Simons

Shilpa Toppo, now with Mitsubishi, served as the study's chair while Nicholas Hatton and Stan Holland of WECC performed the study work.

3. Power Flow and Dynamic Analysis

3.1. Assessment Approach

The currently available 2028 HS1 PF and Dynamics data set was used to address whether there were reliability concerns in the 2028 ADS Phase I data. The 2028 HS1 PF and Dynamics data set were the basis for the Phase I data. Phase I data included the planned generation and network topology for 2028 timeframe (assumptions as of late 2017) as submitted by the transmission planners in consultation with regional planning groups. Phase II data included some additional planned facilities and resources that were seen as important inclusions after WECC stakeholder review (as of late 2018). Phase II data did not include the needed dynamics data, nor were the power flow models verified with the transmission planners, so it was not evaluated. The seven standard disturbances and post transient analysis typically done with WECC base cases were used to evaluate this. The standard disturbances are listed in Appendix A.

The WECC standard disturbances (please see Appendix A for a list of the disturbances) are useful for stressing the system to check for unstable models or areas of potential weakness. The assessment used several metrics:

- **Potential Weak Voltage Support**—TPL-001-WEC-CRT-3.1 WR1.3 states: "Following fault clearing, the voltage shall recover to 80 percent of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load." This criterion was applied to the results of the standard disturbances to check for possible voltage issues.
- **Frequency Response**—If generation was tripped in an outage, the frequency response metric was calculated for that disturbance. NERC uses this metric to calculate the Interconnection Frequency Response Obligation (IFRO) for an entire interconnection. Details on the IFRO can be found here.
- **Load Tripped**—The amount of load tripped as the result of the disturbance due to low voltage or low frequency.

The post transient governor power flow analysis is used to evaluate system performance following critical contingencies such as a double Palo Verde generation outage to identify facilities, if any, whose thermal, voltage, or voltage stability limits may be violated. It can identify areas of potential voltage concerns, as well as larger imbalances if the case does not solve. The analysis compares the voltage before and after the event to identify low voltage conditions that could result in load shedding.

3.2. Assumptions

This assessment serves as a baseline based on assumptions in the 2028 Heavy Summer 1 power flow case. This power flow case uses the same assumptions on generation and loads as those in the original

Anchor Data Set (ADS). When developing the 2028 Heavy Summer 1 (2028 HS1) base case, the following was included as the purpose of the case in the data request: "General 10-year case—with typical flows throughout WECC. Resource and transmission representation coordinated with data from the most recent regional plans of the Regional Planning Groups."

3.3. Data

Data for the power flow analysis included the 2028 HS1 base case data. All base case modifications available in the 2028 HS1 Zip folder were applied to the power flow case. Base case modifications are corrections to data anomalies found after the review and approval process of the case. Before the task force used the case for simulation, minor adjustments were made to correct for software compatibility issues between the PSLF power flow version in which the base case was created and the current version of PSLF being used for the study.

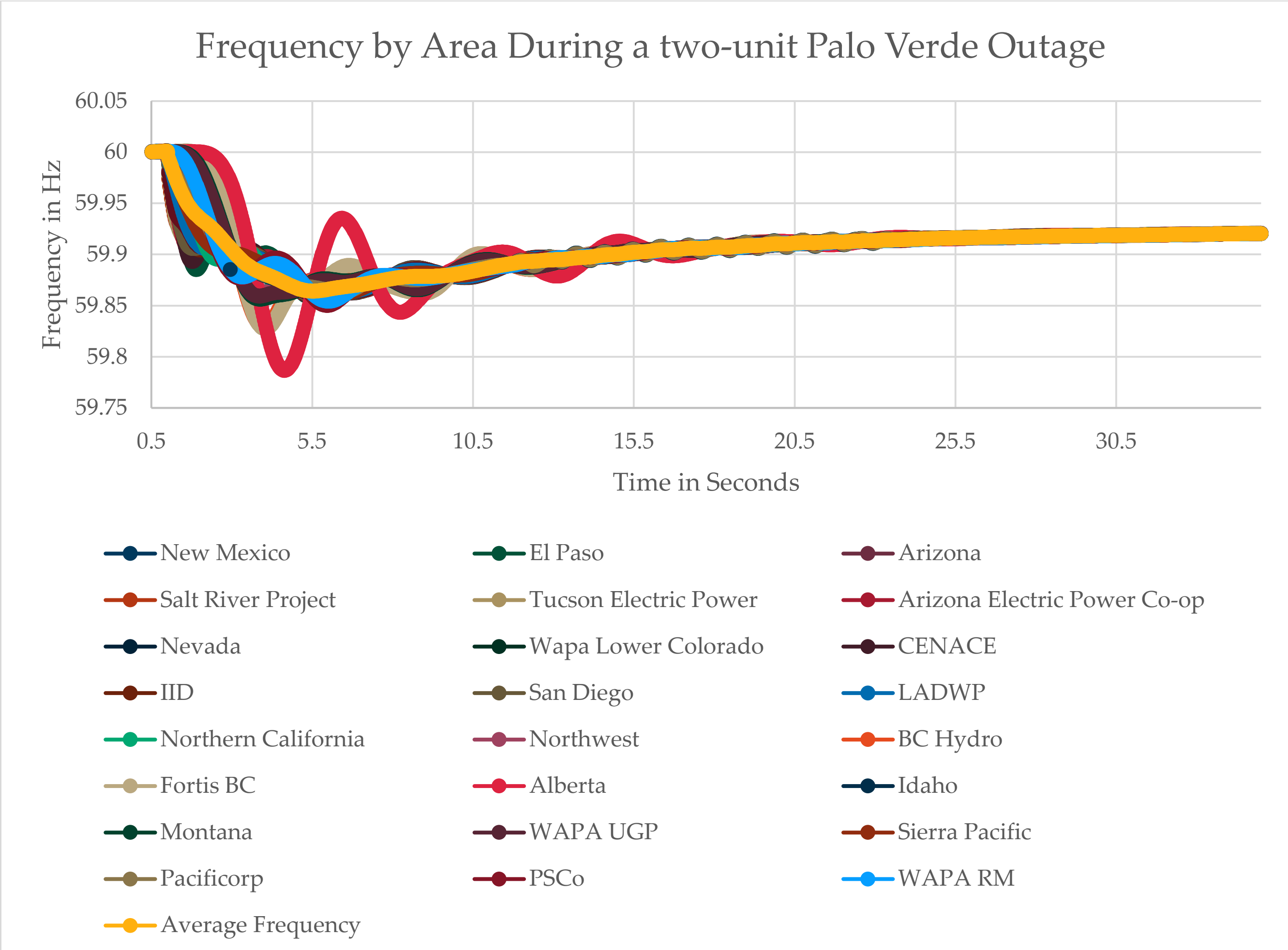
3.4. Collaboration with other WECC assessment teams

The Y10TF shared the scripts it created to generate the results of this study with the other assessment teams. It also shared the results below with the other assessment teams to serve as a baseline for any comparisons they chose to do.

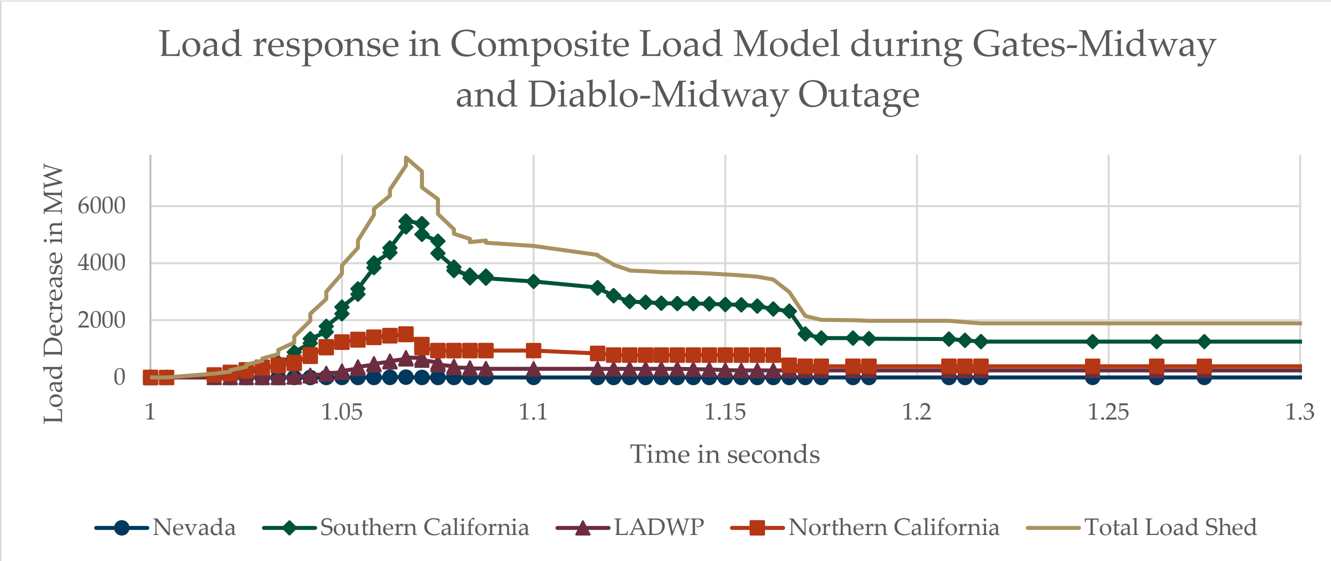
3.5. Analytical Results

The WECC standard disturbances resulted in no significant TPL-001-4 and WECC CRT 3.1 WR1.3 voltage violations, except as noted below. Frequency response was calculated only for outages that included generation tripping. The composite load model (a model used to represent a variety of loads) indicated load tripping in several cases below. In particular:

- The Chief Joe Brake disturbance had no load tripped.
- The Double Palo Verde generation outage had no load tripped. Two generators (a total of 2,747 MW) were tripped. The frequency response measured 1,881 MW/0.10 Hz. This compares favorably to the IFRO, which is 858 MW/0.10 Hz.



- The Colorado River - Red Bluff double line outage had about 250 MW in SCE, IID and APS of load tripped due to under voltage. It is noted that this contingency is beyond the TPL-001-4 standard as the fault type simulated was a three-phase fault in comparison to the single-line-to-ground fault in the standard.
- The Gates-Midway and Diablo-Midway 500kV line outage resulted in 1,800 MW of load tripped. A plot of the load response on an area basis is shown below. Any area not shown had no load trip. This disturbance is a severe 4 cycle, 3 phase fault at a 500 kV bus followed by the tripping of two large transmission lines that are not in common corridor simultaneously. In addition, the three-phase fault is beyond the single-line-to-ground fault type for the simultaneous loss of the two circuits listed in the TPL-001-4 standard. The plot below shows an initial high decrease in load due to very low voltages at those loads. This is expected as part of the electrical characteristics of the load. After the voltage returns to more typical values we see that approximately 1,800 MW of load was tripped due to the momentary, severely low voltages seen. This load would be on the distribution system and would have tripped due to under voltage relays approximated by the composite load model.



- The Brownlee-Hells Canyon 230kV line outage had 3 MW of load tripped. The Remedial Action Scheme (RAS) was activated and tripped 120 MW of generation. The MW/0.10 Hz figure was 1,682. This compares favorably to the IFRO.
- The Daniel Park-Comanche 345kV double line outage had 235 MW of load tripped.
- The PDCI block outage had 96 MW of load tripped. There were four apparent voltage criterion violations as described above in the Assessment Approach section. These were load-serving buses in the Northwest.

The post transient analysis of the Double Palo Verde generation outage showed:

- 145 buses with a voltage change greater than 5%. All were in 5-to-6% range, which is considered acceptable per WECC TPL-001-WECC-CRT-3.
- Five branches and eight transformers were overloaded in the pre-analysis case.
- Nine branches and 34 transformers were overloaded in the post transient case. The highest overload not present in the pre-analysis base case was 128.6%.

The analysis used the summer normal rating (rating 1) to evaluate whether the element was overloaded. It was brought to WECC's attention that using the emergency rating for post contingency analysis, rather than the normal rating, would be a more correct approach. This will be considered for the next study program.

4. PCM Analysis

4.1. Assessment Approach

The ADS process brought together the Western Planning Regions (WPR) and the base case area coordinators to develop a common network topology for both ADS cases. The PCM Data Work Group

(PDWG) and PCM Modeling Work Group (PMWG) worked together to populate and update the other data fields in the PCM model.

In addition to the electrical topology imported from the power flow, the PCM case needs several other types of input data to calculate the security-constrained economic dispatch. Since the PCM is usually run for all hours of the study year, unit availability and limitations are needed, including planned and unplanned outages. Area load and reserve requirements are needed for each hour. For thermal plants, the PCM needs the heat rates, fuel sources, fuel costs, and other costs to perform an economic dispatch. It also needs monthly hydro schedules and hourly wind and solar profiles.

In the past, the PCM cases have attempted to include estimates for major load modifiers such as incremental Distributed Generation (DG), Demand Response (DR), and Energy Efficiency (EE). The incremental DG and DR were typically modeled on the generation side, while the incremental EE was modeled on the load side. In the 2028 ADS PCM v2.2, the same approach was used for DR and EE, but the DG was expanded to represent the total behind-the-meter (BTM) rooftop solar DG or "BTM-DG."

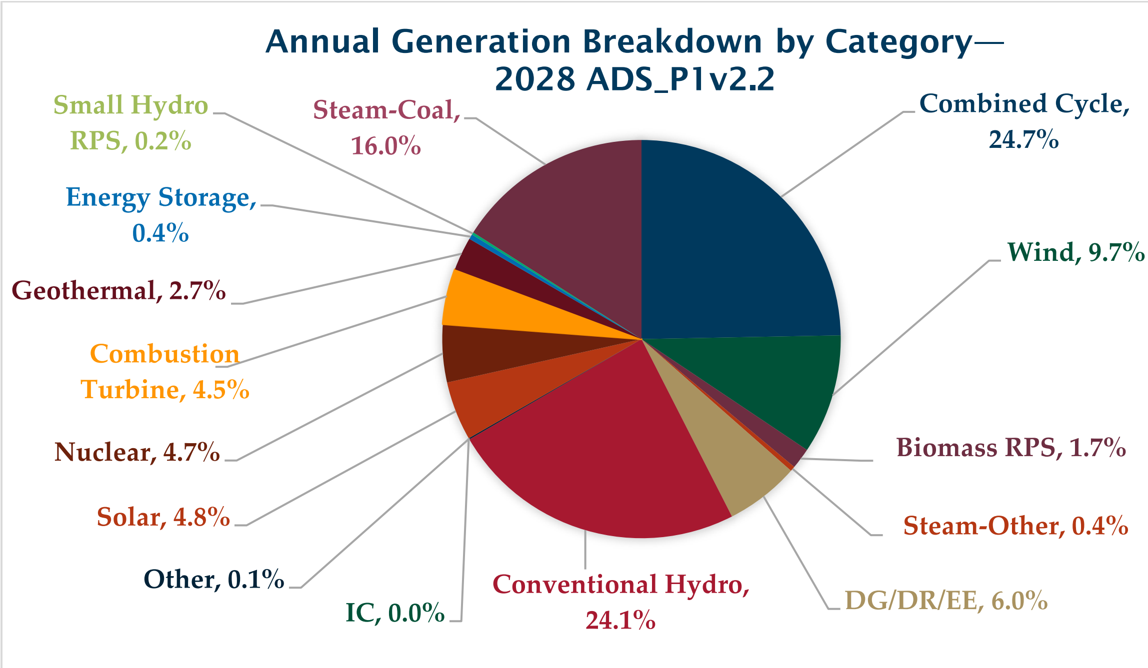
4.2. Analytical Results

During a PCM simulation, generation is committed and dispatched each hour to meet the load requirements and ancillary service requirements, while observing the defined constraints and iterating to the least-cost solution.

4.2.1. Generation

Figure 1 shows the breakdown of the annual generation for the 2028 ADS PCM v2.2 case. The largest share of generation is combined cycle (24.7%), followed by conventional hydro (24.1%) and steam-coal (16.0%). The total renewable share is 18.3%, or about 24.3% if the DG, DR, and EE are included.

Figure 1—PCM Generation Breakdown



4.2.1.1. Unserved Load

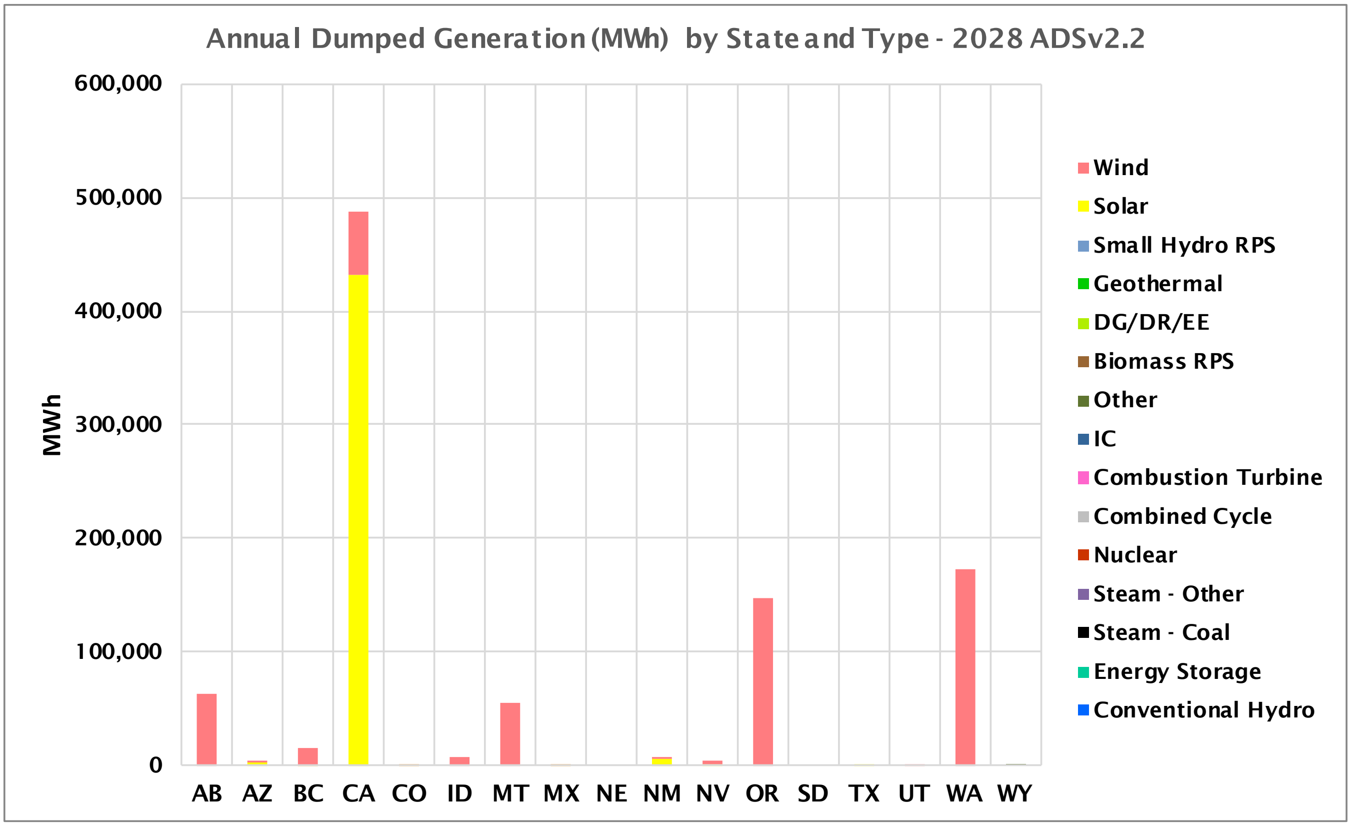
The only area that had unserved load was CFE for three hours on July 19th due to the simulated extreme contingency for the loss of two large combined cycle units in the CFE area in the production cost model. The response of other CFE units and other units in California helped to limit the amount of unserved load; however, the imports from California reached the limit due to path congestion and a small amount of load was unserved under the outage of two large combined cycle generating facilities.

4.2.1.2. Spillage or Dump Energy

The commitment and dispatch order for units is based on modeled operational constraints and cost. Some units are designated as "must run," which gives them priority regardless of cost. Others may have requirements to stay on for a certain number of hours once they have been dispatched. Units with zero fuel cost like hydro, solar, and wind are given priority based on assigned dispatch costs. Occasionally, a unit must be turned on to provide spinning reserves or other ancillary services.

When the output of the priority units for a given hour is greater than the load, the surplus generation must be exported or curtailed. The decision is based on economics and security constraints, which drive the locational marginal price (LMP) calculations. Figure 2 shows the total amount of curtailed or dumped energy by state or province.

Figure 2—Curtailed Energy by State

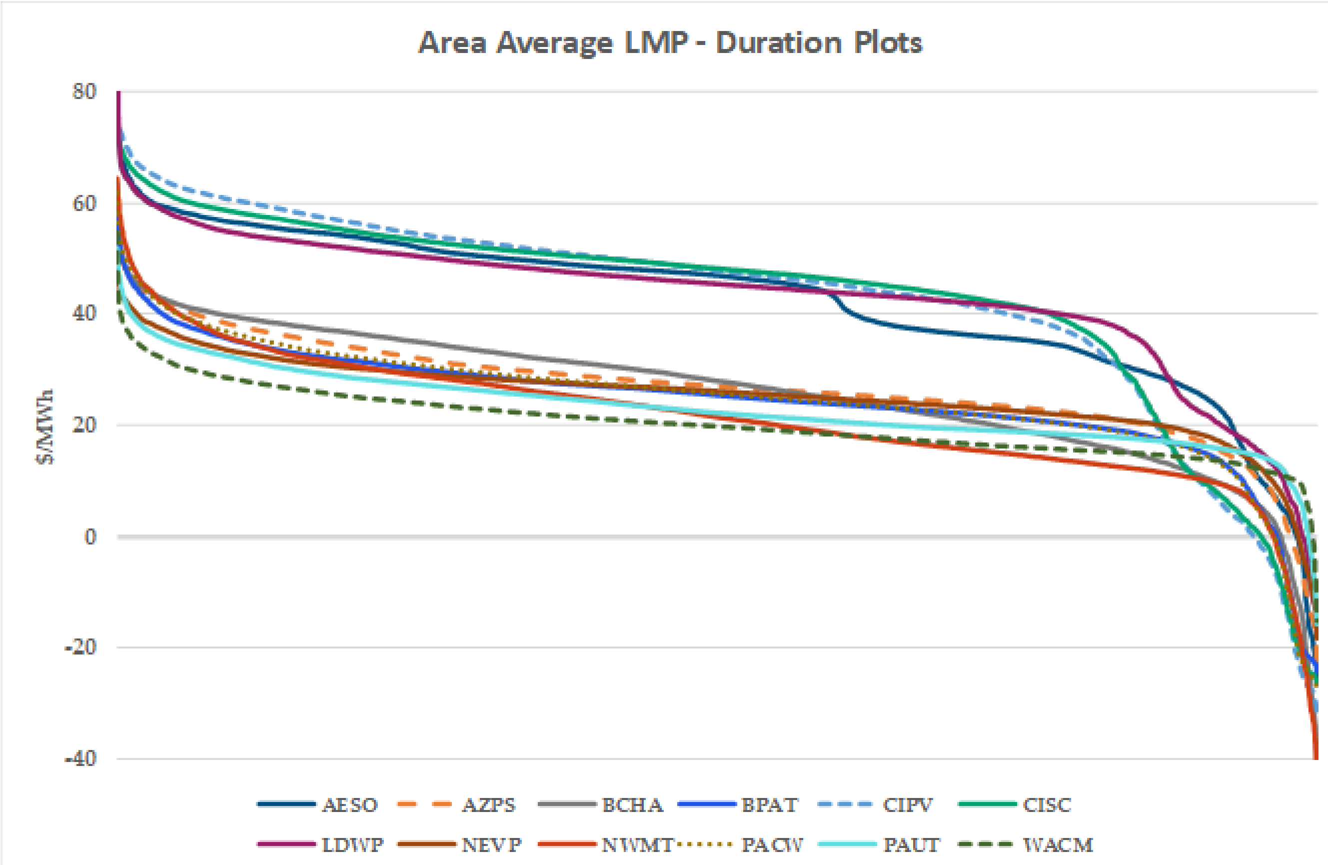


4.2.1.3. Locational Marginal Pricing

The security-constrained economic solution in a PCM is based largely on bus level LMPs. With hourly LMPs at thousands of buses, it is common to summarize the LMPs at some level. The chart in Figure 3 shows the load-weighted LMPs for some key load areas (portions of the Western Interconnection in which loads are aggregated), sorted from highest to lowest.

The states and provinces for the areas in the upper range have legislated a carbon tax on CO2 emissions that raises the LMP prices of fossil-fuel based generation. In addition, California LMPs reflect an import tax to minimize imports of fossil-fuel generation.

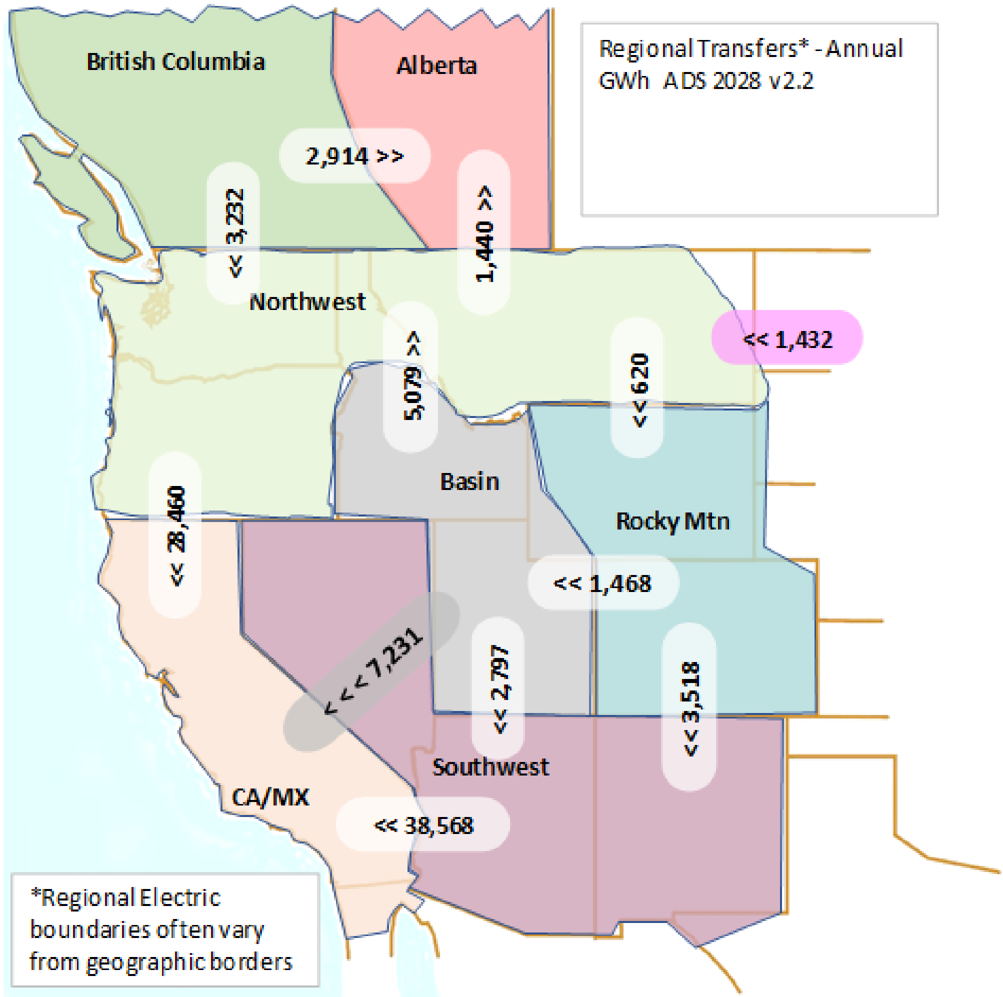
Figure 3—Area LMP Plots



4.2.2. Interchange

The Western Interconnection is made up of several load centers served by local generation and remote generation. The extensive high-voltage transmission system is used to distribute remote generation to the participants. The PCM solution also mimics the price-based transfers of surplus, lower-cost generation from one area or region to another. Figure 4 gives a high-level view of the net annual interchange between sub-regions based on the results from the 2028 ADS PCM v2.2 case.

Figure 4—Net Annual Interchange



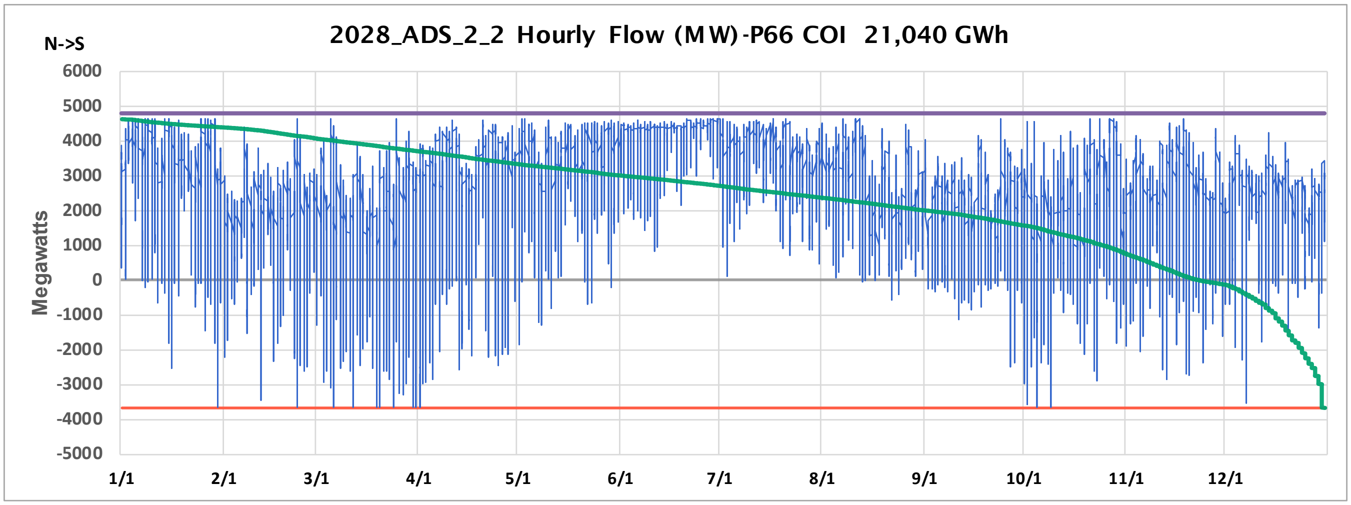
4.2.3. Flows on WECC Paths

The PCM schedules flows (transfers of energy) across the defined paths in the interconnection during its hourly simulation. The results for a few key paths are provided below.

4.2.3.1. Path 66—California-Oregon Intertie (COI)

The California-Oregon Intertie (Path 66) is the group of AC transmission lines connecting California to the Northwest. Figure 5 shows the hourly chronological flows together with a duration plot (plot of hourly flows sorted from highest to lowest). The boundary lines show the forward and backward path limits, which act as constraints in the simulation. The large swings between positive and negative in March, April, and October represent the simulated response to the economic transfer of resources between California and the Northwest – the Northwest cycles between receiving California's solar generation oversupply during the day and delivering Northwest energy to economically meet the loads in the early morning and evening hours.

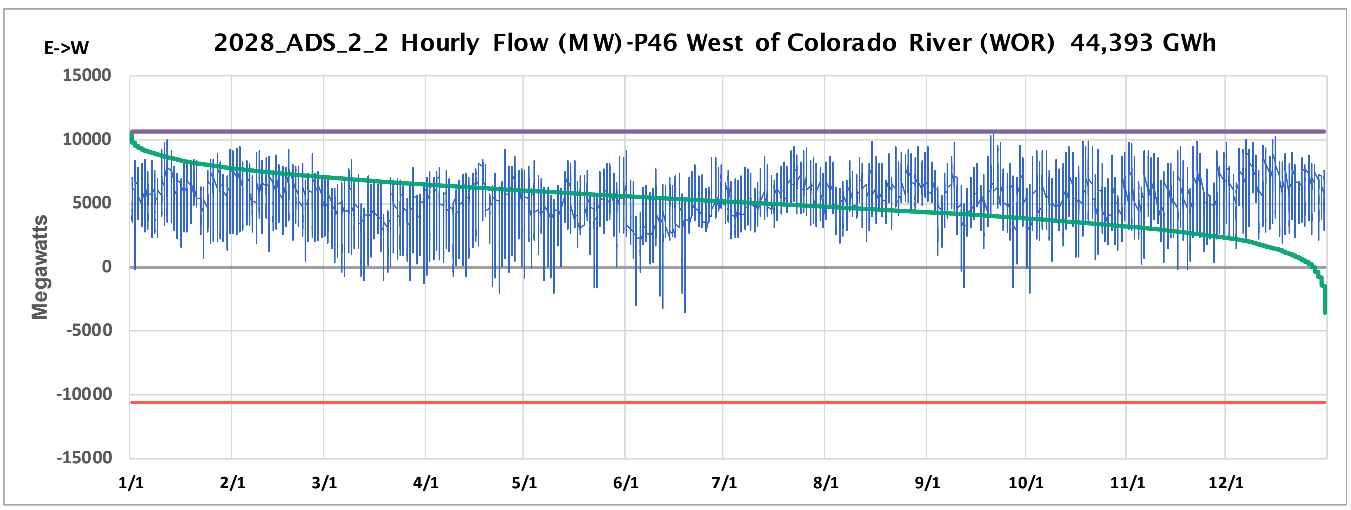
Figure 5—Path 66 Hourly



4.2.3.2. Path 46—West of Colorado River

Path 46 is the collection of transmission lines between California and the Desert Southwest. This is the path that delivers jointly owned and contracted generation such as Apex, Copper Mountain, Desert Star, Harquahala, Hoover, Mesquite, Palo Verde, and others to California. There is some seasonal response to the solar in California, but not nearly as much as on Path 66.

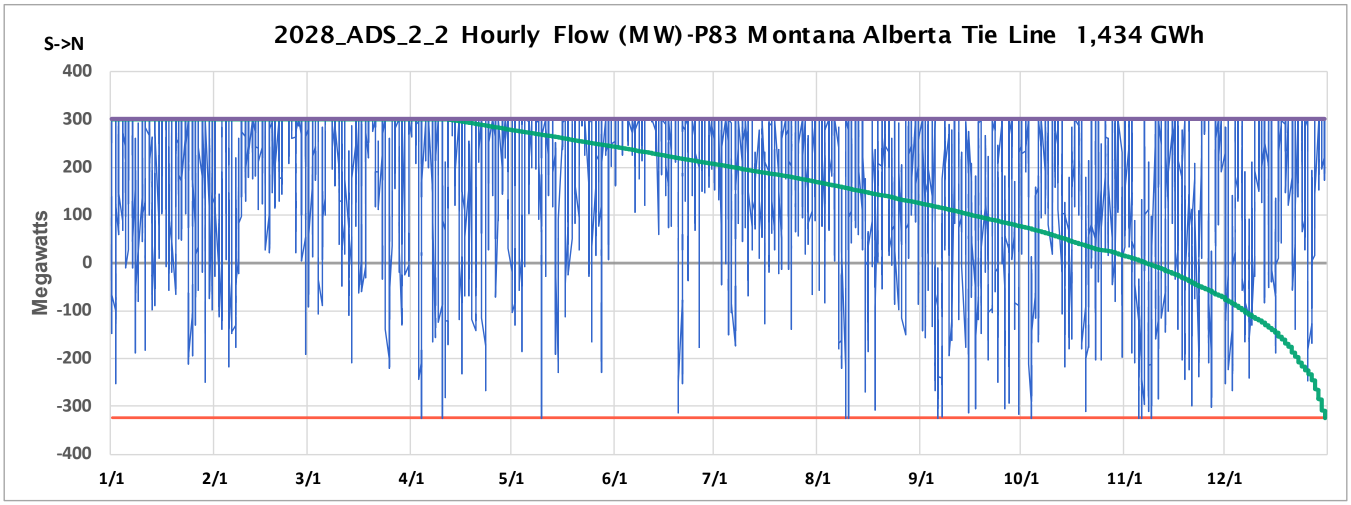
Figure 6—Path 46 Hourly



4.2.3.3. Path 83—Montana-Alberta Tie Line

The Montana-Alberta Tie Line was put in service in 2013 to accommodate power transfers between Alberta and Montana. Since a carbon tax for Alberta was added to the WECC PCM model in 2017, Path 83 has been one of the most highly utilized paths in the WECC study cases. The Alberta thermal generation, with the carbon tax applied, has a higher production cost than similar generation in Montana and Wyoming, leading to many hours of imports on Path 83.

Figure 7—Path 83 Hourly



5. Observations and Conclusions

5.1. Power Flow and Dynamics

The disturbances that included generation tripping indicated a strong generation response. The Gates-Midway and Diablo-Midway 500kV line outage showed what appears to be a large amount of load tripped.[1] The total load for the interconnection in this case was a little over 185,000 MW, so even 1,800 MW tripped was less than one percent of load in the interconnection. The large initial swing in load values appears to be due to the bus voltages sagging to low values for a very brief amount of time. The voltage increases very quickly afterwards, but some load is lost due to composite load model undervoltage relays tripping in the post-contingency condition. Currently approved projects that will add dynamic reactive support to the northern California bulk transmission system are anticipated to help mitigate voltage concerns.

Four potential voltage criteria violations of TPL-001-WECC-CRT-3 were seen in the PDCI block outage at load buses in the Northwest. There may be a voltage support concern for these buses during a PDCI block. Three of these buses appear to be operated as radial lines with parallel connections out of service—this may contribute to the voltage concern. This could also depend on the flow in the PDCI at the time of the block.

The post-transient power flow analysis showed some possible overloads. Further study would be necessary to identify whether these were problems that need to be resolved, if they represent known issues that need to be modeled so that the need for corrective action is evident, or if the emergency

[1] It is noted that the contingency that was evaluated included a three-phase fault which is beyond the TPL-001-4 that requires a single-line-to-ground fault for simultaneous trip of two transmission lines.

rating appropriate for this scenario is not actually exceeded. Overloads could be indicative of the possibility for cascading outages. However, some utilities include overloads in the Year 10 base case to illustrate the need for additional, yet unfunded or unapproved work. For these overloads corrective action may have already been identified, so they would not be issues that need further resolution.

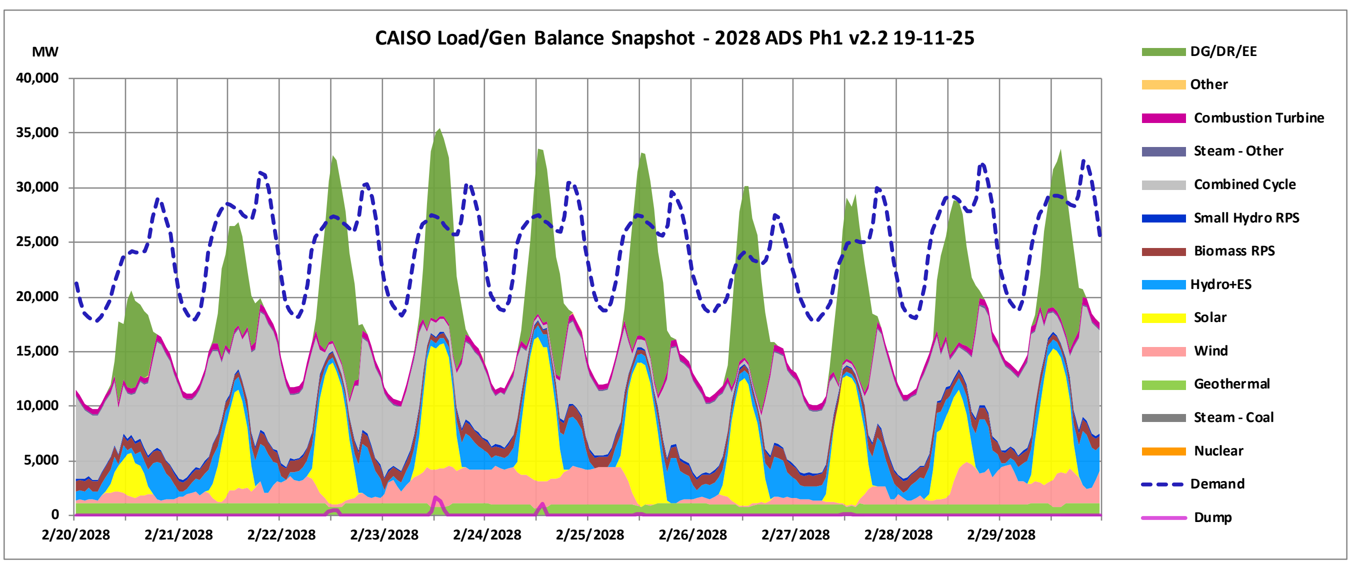
5.2. Production Cost Model

The spilled or dumped generation suggests an opportunity for more energy storage projects that could be "charged" by the spilled energy. The stored energy could be used to help balance the wind and solar generation, especially during the evening ramp. The new emphasis on hybrid projects (solar PV with battery storage) is timely.

The production cost model indicated strong correlation of economic energy transfer between the other BAs and California: (a) during hours when there is an oversupply of California solar generation, other BAs import lower cost energy from solar generation; and (b) whereas when solar generation is unavailable, California imports economic energy from other BAs to supplement its internal available resources. The scenario assessments in the study program likely provide further insights.

Figure 8 shows the ADS generation breakdown results for ten days in February for the CAISO region. The BTM-DG rooftop solar is explicitly modeled as generation and offsetting load. The blank space between the stacked generation and the load (dashed blue line) represents imports. During hours where the generation exceeds the load, the CAISO is exporting power to other BAs.

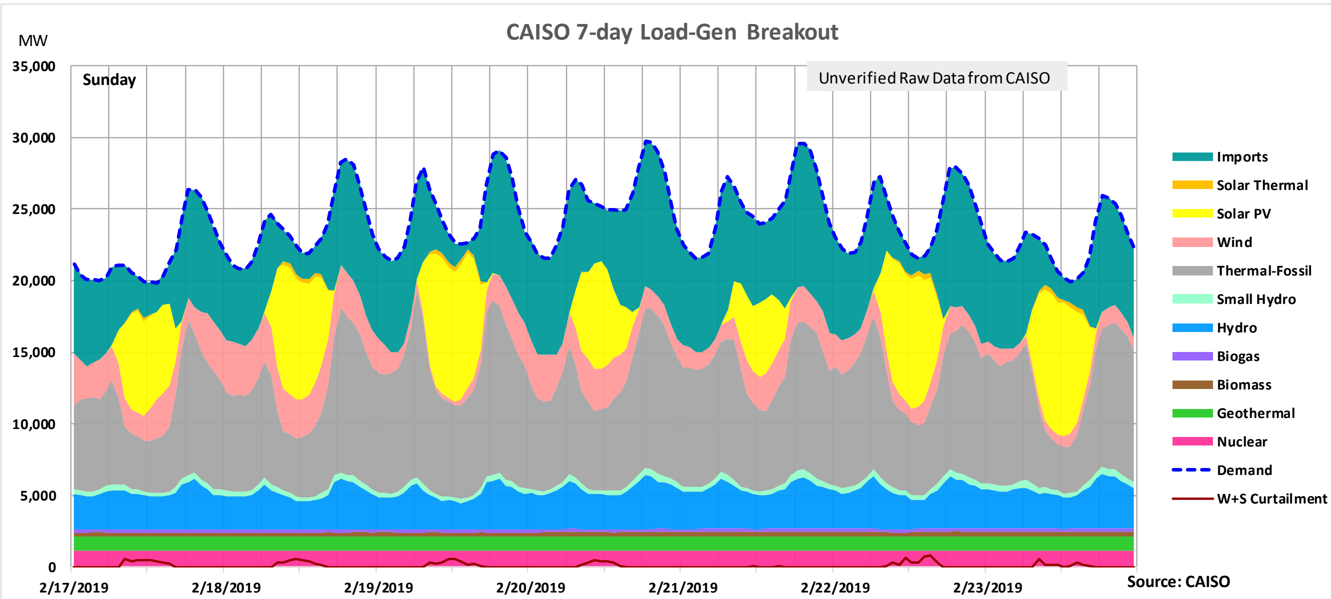
Figure 8—ADS Sample Load/Gen Balance

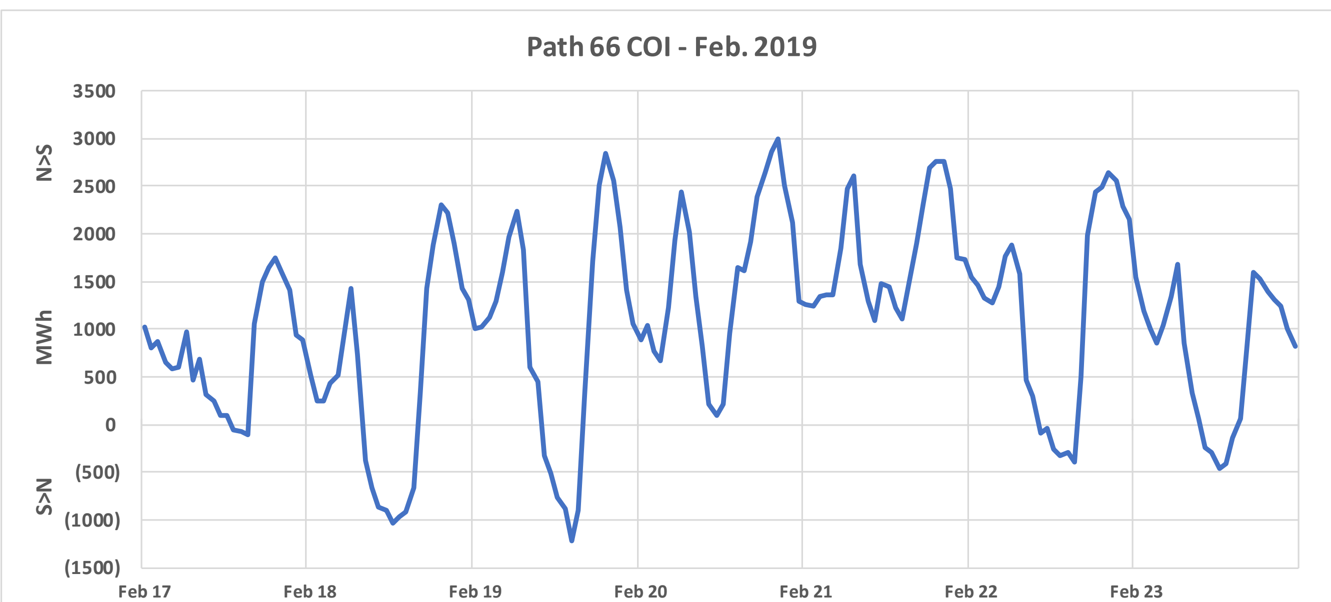


The utility-scale solar and BTM rooftop solar generation is balanced by combined cycle generation, hydro, biomass and other contracted resources when solar generation is unavailable. There are also a few hours of oversupply where generation was curtailed or dumped.

The need for balancing resources exists in 2019. Figure 9 shows the actual generation breakdown from the CAISO for seven days in February 2019. The grid-connected and BTM rooftop solar contributed to reduced load during the daytime hours when solar generation production is at its high output. The solar generation is balanced by other resources such as Thermal Fossil, Imports, Hydro, and sometimes Wind. The graph below Figure 9 shows a strong correlation with the actual flow on Path 66, where the Northwest is contributing to the CAISO imports and receiving the CAISO exports as part of economic energy transfer between regions.

Figure 9—Sample Load/Gen Breakdown from CAISO





6. Recommendations

As this study was intended to be a baseline assessment, the recommendation includes further assessment for the need of potential voltage support and assessment of bulk electric facility loading for the long-term horizon. Cascade potential, based on appropriate facility ratings, should also be evaluated as part of those assessments. The initial data submitted for the 10-year case included some instances of equipment loaded above their normal ratings. Some of these overloads may be instances where mitigation of the issues is not yet funded or planned. Those doing studies, who have concerns about these overloads, should request guidance of the data providers on how to handle these overloads if they believe they are affecting their study outcomes. Also, DG was not yet modeled in the published WECC base cases when this case was developed. With the addition of DG, more study would be needed to verify whether the load lost included DG as well.

7. Appendix A—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;
- 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.