WECC

NERC-WECC Assessment of High Penetration and Ramping of Variable Energy Resources

February 2022

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Executive Summary

On September 10, 2020, FERC held discussions with NERC and WECC in response to the heat wave from August 14 through 18. During this call, FERC shared four items it wanted NERC and WECC to address. The first two items concerned changes in audits. The third item addressed making changes to the seasonal assessments and the Long-Term Reliability Assessment (LTRA) to better reflect more realistic scenarios based on the effects of the 2020 summer heat wave event. WECC is participating with NERC and other Regional Entities to address this third item.

The fourth item of interest to FERC staff (FERC Item #4) involves looking at the transition periods of high levels of renewable resource availability followed by low levels of renewable resource availability, such as just before and after the sun sets in areas with high levels of solar generation. The goal is to understand how these transitions can affect operations reliability. To address FERC's request, NERC and WECC employed a two-pronged approach. First, WECC conducted several studies to analyze these transition periods from several different perspectives, including resource adequacy, reserves, ramping, and other relevant operational perspectives. Second, reliability experts from the Electric Reliability Organization Enterprise (EROE) evaluated measures that can be taken by NERC (e.g., enhancements to Reliability Guidelines, Reliability Standards, and/or other reliability risk mitigation methods) to address operational concerns resulting from these energy production and power transfer transitions.

WECC and NERC performed studies in five areas to identify potential concerns. The studies included Power Flows of periods around the event, potential net demand ramping in future years, a future resource adequacy assessment, and historical Control Performance Scores. In addition, NERC performed an analysis to identify whether any changes should be made to Reliability Standards. Important findings from each study are listed below.

Important Findings

- Power Flow—The power flow work performed for this report did not reveal any significant System Operating Limit (SOL) exceedances or results that deviated from expected outcomes. The results indicate that the Western Interconnection performed as expected under the stressed conditions.
- Net Demand Ramping—Morning and afternoon ramping in areas outside of California is not a concern today. However, the study identified several BAs exhibiting system ramps by 2025 as significant as the California Independent System Operator (CAISO) ramps. Ensuring adequate amounts of flexible resources are added will be critical to address future ramping needs.
- Resource Adequacy—Based on the hourly production cost analysis of expected system conditions, if future resources are built as currently planned, the system is expected to be resource adequate. This study looked at expected, or average demand and resource availability conditions. Results would be different when studying high demand or low availability

conditions. Additionally, the study does not include intra-hour demand and generation variability, which can have a substantial impact on resource adequacy. As more variable resources like wind and solar are added to the grid, the variability of generation availability increases. Probabilistic studies look at a range of possible scenarios and test many combinations of demand and generation. Although the results of this set of studies indicate that the interconnection should be resource adequate, under different supply and demand assumptions the results may be different, and probabilistic studies would identify those conditions. WECC's Western Assessment of Resource Adequacy, published in December of 2021, includes an extensive probabilistic analysis.

- Control Performance Standard 1 (CPS1)—The CPS1 score is a measure of how much a BA is over- or under-generating relative to its load. As such, it is a measure of operational control. The object of this analysis was to determine whether operational control, (as measured by CPS1), had changed over time, and particularly to determine whether any changes had been driven by changes in generation mix or market structure. The analysis was inconclusive, not identifying any one driver that overwhelmingly influences CPS1 scores. Consequently, this analysis supports NERC's recommendations concerning the CPS1 scores presented in chapter 5 and found no reason to modify the current CPS reporting process.
- Assessment of System Operations During Large Transactions of Variable Generation Output—A review of the NERC Reliability Standards and Reliability Guidelines appears to show the current set of Reliability Standards should largely ensure the reliable operation of the bulk power system. This includes requirements on balancing, emergency operation and preparation, and transmission operation. Some enhancements to the Reliability Standards should be considered, and recommendations to enhance operator guidelines are included.

Recommendations

- Entities should continue to monitor net demand curves. As more variable generation is added to the grid, the morning and evening demand ramps could stress the reliability of the grid. Monitoring these ramps, forecasting them, and applying stress-test scenarios will allow entities to identify and address concerns to avoid reliability challenges.
- To provide further guidance on meeting balancing requirements, NERC should enhance the existing Reliability Guideline on Operating Reserve Management to provide practices on managing and establishing operating reserve requirements in recognition of increasing ramp conditions.
- The Reliability and Security Technical Committee (RSTC) should produce a Reliability Guideline in support of TOP-002-4 that makes it clear that steep ramps associated with VER need to be a part of the next-day Operating Plan and recommend a longer time-frame for analyzing and addressing those issues—whereas the current requirement is one day. Further, the guideline should include best practices for studying system states and appropriately

procuring, committing, and dispatching resources under large ramping conditions. We further recommend gathering industry feedback to determine if next-day Operating Plans should have longer lead-times within TOP-002, providing further time to ensure operating reliability and energy sufficiency.

- NERC's Energy Reliability Assessment Task Force (ERATF) is evaluating the flexibility required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year. The ERATF should continue its work to identify solutions to the resource challenges associated with the increase in variable generation resources, including potentially recommending new guidelines and enhancements to Reliability Standards.

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Introduction

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The fourth item (FERC Item #4) was to evaluate the transition periods of high levels of renewable resource availability followed by low levels of renewable resource availability. The goal is to understand how these transitions can affect operations reliability. To address FERC's request, NERC and WECC employed a two-pronged approach. First, WECC conducted several studies to analyze these transition periods from several different perspectives, including resource adequacy, reserves, ramping, and any other relevant operational perspectives. Second, reliability experts from the EROE evaluated measures that can be taken by NERC (e.g., enhancements to Reliability Guideline, Reliability Standards, and/or other reliability risk mitigation method) to address operational concerns resulting from these energy production and power transfer transitions.

Background

The electric industry is rapidly moving to higher percentages of renewable resources in an effort to reduce greenhouse gas emissions created by some forms of conventional electric generation. The vast majority of these renewable resources are made up of wind and photovoltaic (PV) solar facilities. Therefore, the output of these resources is dependent upon the availability of wind and sunshine. Since wind and sunshine are variable, the electrical output of these facilities will be variable. As such, these resources have been referred to as variable energy resources (VER).

This resource variability, in large amounts, presents challenges to Balancing Authorities (BAs) who must maintain a balance between their scheduled interchange, generation, and load in order to support interconnection frequency and limit inadvertent flow on the transmission system. Historically, BAs did not routinely encounter significant variability of generation that would result in steep ramp ups or downs of generation. Typically, these types of ramps were encountered during generator trips which were not routine and were limited by the maximum size of a single resource. With higher penetrations of VER, BAs experience, on a daily basis, steep ramps of generation. Of particular concern, is the steep ramp down of generation that occurs daily when PV solar facilities decrease their output as the sun is setting.

The Emerging Challenge for System Planners and Operators

When large percentages of PV solar facilities are installed, these ramps can consist of thousands of megawatts over a few hours. As can be seen in Figure 1, a recent ramp for CAISO was 11,240 MW over a three-hour period which correlates to 3,746 MW per hour, 1,873 MW per 30 minutes, and 936 MW per 15 minutes.

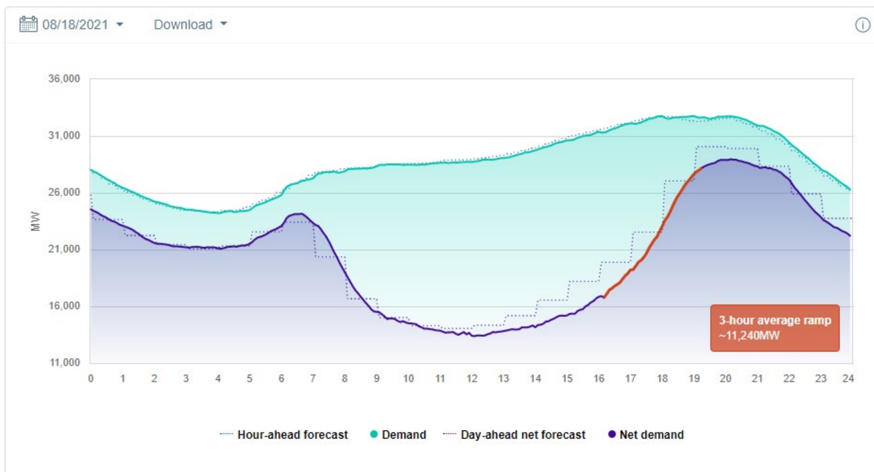


Figure 1: CAISO ramping example from August 18, 2021 showing a large three-hour ramp

This trend is expected to increase as more VERs (specifically solar PV resources in the California example) are integrated into the system—on both the bulk-power system (BPS) and the distribution system. For example, CAISO has over 16 GW of solar PV capacity and must proportionally increase reserves to respond to growing variability caused by cloud cover, rain, or inverter-related issues. With continued growth of distributed solar, CAISO's three-hour net-load ramping needs can exceed 15 GW. Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 20,000 MW by January 2023[1], an increase of over 30% compared to January 2019 (see Figure 2).

Upward ramping shortages are most prevalent in late afternoon when solar generation output decreases while system demand is increasing. Without sufficient upward ramping capability within the balancing area to offset the loss of solar output during these times, neighboring BAs are called

Ramping

Ramping is a term used to describe the loading or unloading of generation resources to balance net demand with supply during daily system operations. Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of non-dispatchable resources, the consideration of system ramping capability is an important component of planning and operations.

[1] https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2020.pdf

on to provide the necessary support to balance supply and energy needs, if they are not also experiencing similar ramps.

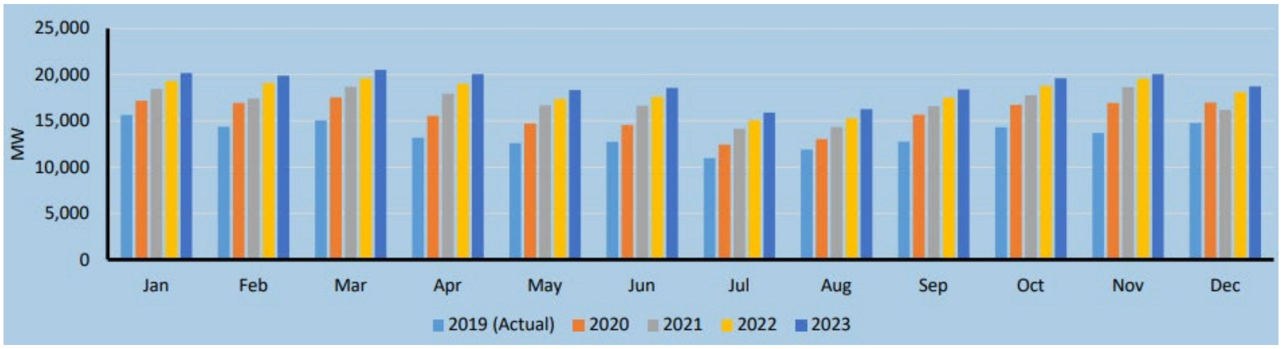


Figure 2: CAISO projected future three-hour ramps, monthly through 2023

To address FERC Item #4, NERC and WECC formed a team to study the August Heat Wave Event focusing on system conditions during the outages and possible future effects. WECC structured the study to look for drivers that could lead to loss of load, not to determine what caused the loss. The findings of each study group are presented in separate chapters of this report.

Chapter 1—Power Flow—explains the results of the power flow analysis of system conditions, generation, and transmission during the load-shedding events to identify SOL exceedances that existed during the events. This analysis produced a good indicator of how the interconnection looked during the August event and showed which elements, if any, were critical to grid reliability. Kent Bolton, Senior Engineer, led the work with help from members of the Southwest Power Pool (SPP) team.

Chapter 2—Net Demand Ramping—reports the analysis of how the changing resource mix may have an impact on future net demand morning and evening ramps for each Balancing Authority (BA) for select months in years 2025 and 2030. These ramping concerns may be related to the expected times when renewable generation output changes in the early morning and late afternoon. Amanda Sargent, Senior Resource Adequacy Analyst, led the study work for this chapter.

Chapter 3—Resource Adequacy—reports the results of a production cost model (PCM) used to compare expected resources with forecast demand for 2025 and 2030 to assess resource adequacy. This part of the study highlights areas that may not have adequate resources to ensure reliability with the expected future resource mix. Stan Holland, Senior Engineer, performed the PCM work with help from the System Adequacy Planning (SAP) group.

Chapter 4—Control Performance Standards—explains the work done for the assessment of historical BA hourly control performance standard (CPS) scores to identify trends associated with the changing resource mix. This section examines CPS1 scores, which are indicators of control performance, during periods when renewable generation output quickly increases or decreases. Peter Ashcroft, Senior Data Specialist, led the study work with help from other WECC staff members.

Chapter 5—Assessment of System Operations During Large Transitions of Variable Generation Output—is a look at the NERC standards that direct what BAs must do regarding ramping and resource adequacy. The chapter summarizes the individual standards and highlights any required and recommended considerations to ensure the reliability of the BPS. Rich Bauer, Associate Principal Engineer, NERC staff, led the efforts to examine existing standards that may be affected by the changing resource mix and the specific operating concerns of large transitions of variable generation output.

Chapter 1—Power Flow

One method of review that was identified for investigation of the August 2020 West-wide heat wave event was power flow modeling. A power flow model is a snapshot of an interconnected electrical system at an instant in time and includes information such as voltages, path flows, power flowing on transmission lines and transformers, and other parameters. The power flow model is used to examine the parameters and determine how close a power system is operating to a potentially dangerous operating situation. Power flow models are also used to see whether the interconnected system remains within required operating limits during contingencies or "what if" events. For example, one could start with the power flow model, remove a transmission line from service, then see whether power can redistribute throughout the remaining interconnected system without causing high or low voltages or overloaded transmission elements. This is exactly what was done in this study.

One of the difficulties in preparing a power flow model is developing a model that accurately reflects conditions in the electrical system at the exact time of interest. SPP, as a Reliability Coordinator in the Western Interconnection, monitors voltages, power flows, and many other elements related to the real-time operation of the interconnected electrical system. SPP can also create snapshots of the system on a regular basis. For this study, two snapshots of the Western Interconnection were obtained and used to review some of the markers that can be indicative of the health of the system.

The first snapshot models the Western Interconnection on August 14 at 5:24 p.m. PST. The first snapshot was selected because it was within the August 2020 West-wide heat wave and reflected a heavily loaded system later in the afternoon with solar power still being generated at high levels. The second snapshot was used because it was still during the heat wave and reflected a heavily loaded system, but, unlike the first snapshot, at 8:27 p.m. PST, August 15, no solar power was being generated.

The purpose of this study was to focus on the Western Interconnection as a whole to determine whether operation of the system was limited (as far as power flow methods could determine) by the heavy load levels and the availability or lack of availability of generation to replace the solar energy that decreased, then ceased, as the sun set. While the entire Western Interconnection was studied, greater emphasis was placed on California, since this is where load was shed during the event.

Study Approach

For this study, only steady-state power flow parameters were analyzed (e.g., bus voltages and angles, transmission line and transformer power flows, and WECC Path Flows). Dynamic or transient simulations would provide more information, but these types of studies take much more effort and are relegated to future work.

The GE PSLF program was used for this study and the Steady-State Tools (SSTOOLS) routine was used to perform the contingency or outage simulations. A contingency definition file was created that defines which transmission elements are removed from service. For this study, only transmission elements of 200 kV and above and generators of 200 MVA and above were removed from service. The smaller subset of contingencies was used because these elements created the largest disturbances in the interconnection and could be seen as "worst-case" scenarios. The outage simulations performed are called N-1 contingencies. This means that the program records all pertinent information from the power flow snapshot and then removes one element (transmission line, transformer, or generator) from service. Removing one element changes bus voltages and power flows in the original snapshot. These changes are then compared with the original parameters in the snapshot. In total, over 9,000 contingencies were simulated; approximately 4,500 on each snapshot.

Because two snapshots were studied, results for each snapshot were assessed separately and were then compared to determine whether one of the snapshots behaved differently than the other.

Study Results

SSTOOLS produces a very large report file with several output types:

- **Bus voltage exceedances**—Bus voltages fluctuate from day to day and even hour to hour. The desire is to keep these fluctuations as small as possible. In this study, any significant increase or decrease of actual voltage was reported.
- **Bus voltage deltas**—Any significant bus voltage fluctuation of 5% or more was reported.
- **Line and transformer flow exceedances**—Transmission elements all have limits on how much power can flow through them. Any flows over 100% of normal rating were reported.
- **Path flow exceedances**—Any flows over 100% were reported.

Bus voltages were monitored for being above or below their nominal voltage during every contingency. A few buses were reported as being over or even under their respective nominal voltage after a contingency but, generally, these buses were already higher than nominal because of the high demand in the initial snapshot. Therefore, another small voltage increase was not deemed noteworthy.

Bus voltage deltas were examined for an increase or decrease above a certain percentage as opposed to a nominal value, as in the bus voltage mentioned above. For example, suppose a bus had a nominal voltage rating of 230 kV, but was always operated at 240 kV. During a contingency, the bus voltage rose to 242 kV. In this case, an error could be reported under the bus voltage criterion, but not for the bus voltage delta criterion. Some voltage deltas above 10% were seen during this study, but all were attributable to and contained in small radial systems that were created during the contingency and were not part of a large systemic voltage concern. Also, none of these voltage delta reports were in California.

Line and transformer flows are automatically affected when contingencies take place because electricity follows the path of least resistance. If a transmission line is opened during a contingency, the power that was flowing on it will redistribute throughout the remaining system, causing flows on other transmission elements to increase or, in certain instances, even decrease. Several light transmission element overloads were seen during this study but were within reported emergency rating limits.

Paths within WECC are typically composed of more than one transmission element and are monitored continually for power flows approaching limits. Figure 3[2] lists the path flows from the initial power flow snapshots before any contingencies were performed. Most path flows were less than 50% in the initial snapshots, but one path, SDG&E—CFE, was loaded at 112.7% of its maximum rating in the August 14 case.

[2] The Northwest AC Intertie (NWACI), comprised of Path 66 (COI) and Path 76 (Alturas Project), was not fully loaded during the heat wave as the path had been derated by 930-1,250 MW, reflecting the transmission constraints that were in place during the heat wave event. More information about the derate is included in the WECC **August 2020 Heat Wave Event Report.pdf (wecc.org)**.

PATH #	PATH NAME	AUG 14 @ 5:24 pm PNET	% of Path Rating	AUG 15 @ 8:27 pm PNET	% of Path Rating	Forward Rating, MVA	Reverse Rating, MVA
1	ALBERTA - BRITISH COLUMBIA	824.7	82.5%	825.2	82.5%	1000	-1200
3	NORTHWEST - CANADA	992.2	33.1%	1590.4	53.0%	3000	-3150
4	WEST OF CASCADES - NORTH	1419.3	13.9%	1197.8	11.7%	10200	-10200
5	WEST OF CASCADES - SOUTH	34	0.5%	512.0	7.1%	7200	-7200
6	WEST OF HATWAI	479.7	11.2%	401.1	9.4%	4277	0
8	MONTANA - NORTHWEST	496.6	22.6%	565.9	25.7%	2200	-1350
14	IDAHO - NORTHWEST	355.5	14.8%	440.5	18.4%	2400	-1340
15	MIDWAY - LOS BANOS	152.4	3.2%	-449.9	22.5%	4800	-2000
16	IDAHO - SIERRA	-253.3	70.4%	-318.8	88.6%	500	-360
17	BORAH WEST	278.2	10.9%	81.8	3.2%	2557	-1600
18	MONTANA - IDAHO	-218.5	64.8%	-335.9	99.7%	383	-337
19	BRIDGER WEST	-156.8	12.5%	-163.7	13.1%	2400	-1250
20	PATH C	500.4	31.3%	726.9	45.4%	1600	-1250
24	PG&E - SPP	28.2	17.6%	31.6	19.8%	160	-150
25	PACIFICORP/PG&E 115 KV INTERCON.	10.2	10.2%	15.5	15.5%	100	-45
26	NORTHERN - SOUTHERN CALIFORNIA	-2798.4	93.3%	-1325.6	44.2%	4000	-3000
28	INTERMOUNTAIN - MONA 345 KV	239.4	17.1%	245.7	17.6%	1400	-1200
30	TOT 1A	-184.3	Not defined	-264.6	Not defined	650	0
31	TOT 2A	76	11.0%	153.2	22.2%	690	0
32	PAVANT, INTRMTN - GONDER 230 KV	103.2	23.5%	90.3	20.5%	440	-235
33	BONANZA WEST	311.8	39.7%	388.8	49.5%	785	0
35	TOT 2C	-289.3	49.9%	-259.0	44.7%	600	-580
36	TOT 3	-287.6	Not defined	-228.2	Not defined	1680	0
38	TOT 4B	-45.5	Not defined	-11.0	Not defined	880	0
39	TOT 5	-307.4	Not defined	-373.6	Not defined	1680	0
40	TOT 7	308.3	34.6%	152.2	17.1%	890	0
42	IID - SCE	-75.6	Not defined	-79.7	Not defined	600	0
45	SDG&E - CFE	-901.4	112.7%	-430.1	53.8%	408	-800
46	WEST OF COLORADO RIVER (WOR)	65	0.6%	-610.7	5.5%	11200	-11200
47	SOUTHERN NEW MEXICO (NM1)	544.9	52.0%	334.4	31.9%	1048	-1048
48	NORTHERN NEW MEXICO (NM2)	886.1	41.2%	706.0	32.8%	2150	-2150
49	EAST OF COLORADO RIVER (EOR)	1393.7	13.8%	870.3	8.6%	10100	0
52	SILVER PEAK - CONTROL 55 KV	0.7	4.1%	-0.6	3.5%	17	-17
54	CORONADO - SILVER KING - KYRENE	584.8	39.1%	699.5	46.8%	1494	0
55	BROWNLEE EAST	267	13.9%	622.2	32.5%	1915	0
58	ELDORADO - MEAD 230 KV LINES	-161.1	14.1%	5.7	0.5%	1140	-1140
59	WALC BLYTHE - SCE BLYTHE 161 KV	-3.1	Not defined	-19.0	Not defined	218	0
60	INYO - CONTROL 115 KV TIE	1.5	2.7%	10.6	18.9%	56	-56
62	ELDORADO - MCCULLOUGH 500 KV	599.9	23.1%	680.9	26.2%	2598	-2598
66	COI	3252.3	67.8%	4070.8	84.8%	4800	-3675
71	SOUTH OF ALLSTON	1245.3	45.7%	1297.4	47.6%	2725	-1170
73	NORTH OF JOHN DAY	-2225	28.9%	-2630.2	34.2%	7700	-7700
75	HEMINGWAY - SUMMER LAKE	101.6	6.8%	211.2	14.1%	1500	-550
76	ALTURAS PROJECT	97.8	32.6%	128.0	42.7%	300	-300
78	TOT 2B1	295.5	45.7%	341.9	52.8%	647	-700
79	TOT 2B2	179.1	67.6%	193.0	72.8%	265	-300
80	MONTANA SOUTHEAST	-58.4	9.7%	-68.2	11.4%	600	-600
81	SNTI-S.NEVADA TRAN INTERFACE	-859.8	22.7%	-721.6	19.0%	4533	-3790
82	TOTBEAST	165.3	6.7%	411.0	16.7%	2465	0
83	MATL	-14.5	4.8%	-129.2	43.1%	325	-300
84	HARRY ALLEN - ELDORADO (HAE)	479.8	13.7%	985.5	28.2%	3496	-1390
85	AEOLUS WEST PATH (POST GATEWAY)	59.9	2.2%	-21.1	1.2%	2670	-1800
86	WEST OF JOHN DAY	-1698.3	Not defined	-1587.5	Not defined	4760	0
87	WEST OF MCNARY	-408.9	Not defined	-377.0	Not defined	4925	0
88	WEST OF SLATT	-2539.6	Not defined	-2925.8	Not defined	4760	0
89	SNTI+ -S.NEVADA TRAN INTERFACE+H	-380	8.1%	263.9	4.2%	6257	-4681

Figure 3: Path flows before performing contingencies

Findings

As noted earlier, steady-state power flow simulations are limited in the amount of information they can provide; however, the available information indicates some aspects of the health of a power system. In the studies performed for this report, no large problems or deviations were noted. Loads in both snapshots were high, but bus voltages and power flows looked reasonable and were not excessive, even under contingency conditions.

The results of the power flow simulations indicate that the Western Interconnection performed adequately under the stressed conditions. Also, only two specific snapshots were used in this review due to limited availability of power flow models. Since generation, loads, and power flows change continually, it's impossible to study every condition that took place during the Heat Wave event.

The contingency results for each power flow snapshot were also compared. Results varied between snapshot, mainly because each represents a different day and time of day. The August 14th snapshot reflects early afternoon with corresponding high solar output while the August 15th snapshot reflects evening conditions with no solar output. Given these differences in solar output, no remarkable differences between snapshot results were seen.

Chapter 2—Net Demand Ramping

A major contributing factor in potential future load-shed events, like those experienced during the August 2020 Heat Wave Event, is steep afternoon ramps as solar generation declines when the sun sets. WECC staff analyzed all BAs in the interconnection to determine whether other BAs could encounter problematic ramping curves as more variable generation is added to their BA areas (BAA).

WECC analyzed potential ramping risks by BA due to increases in VERs, with a concentration on the potential effects of the growth of solar (see Figure 4 and Figure 5). Current net demand was compared to a range of potential futures to reflect resource retirements and acquisition plans' effects on the diversity of regional portfolios.

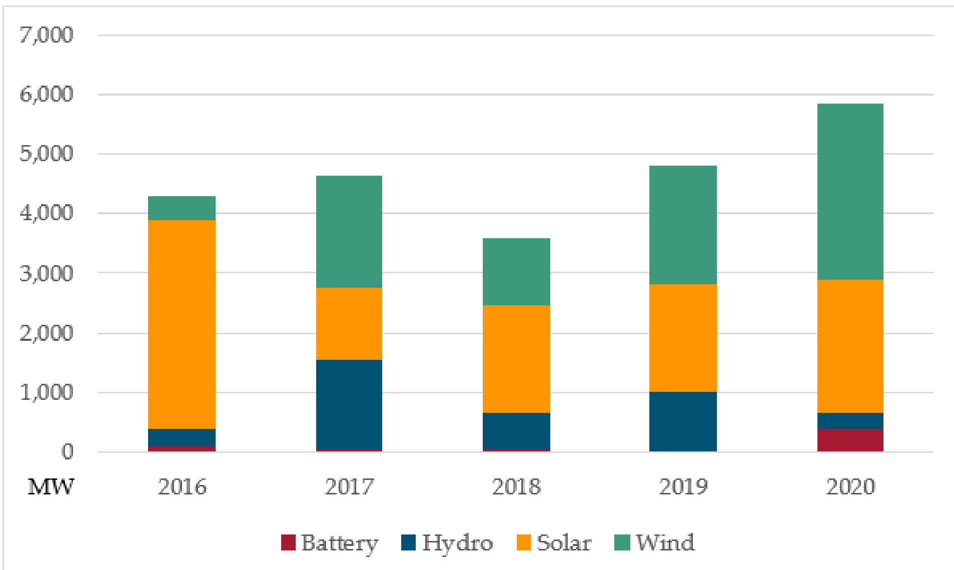


Figure 4: WECC Historical incremental annual renewables, new capacity additions

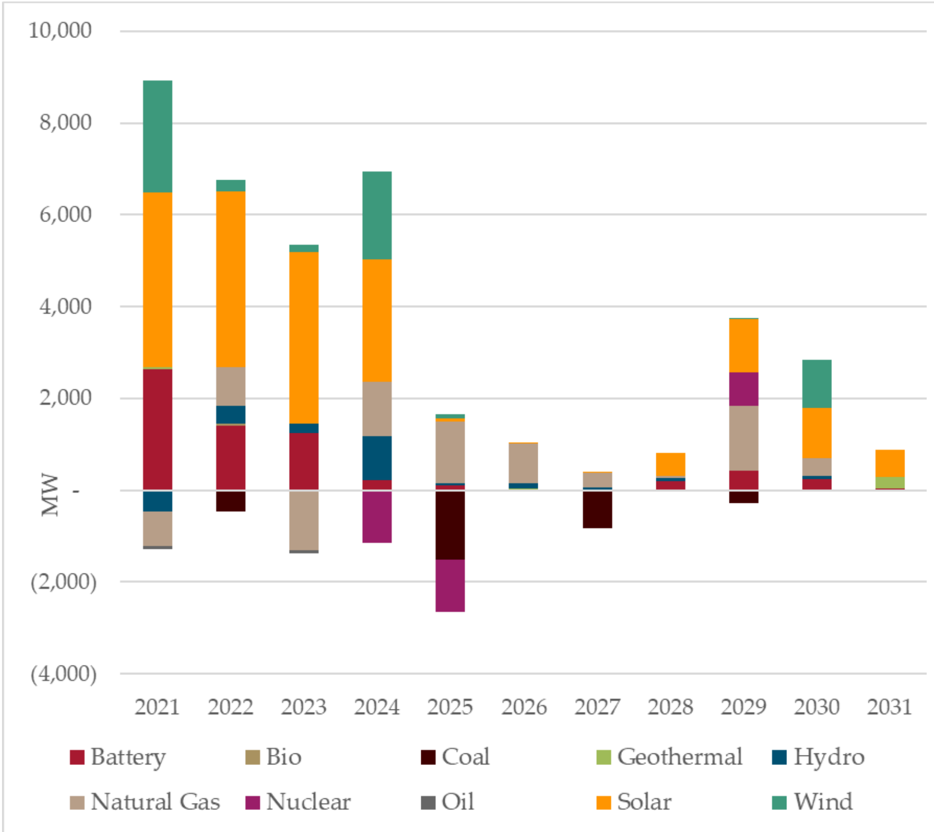


Figure 5: WECC Planned incremental annual capacity changes by resource type

The BAs' results were categorized into high and low risk based on the slope of the ramp. Roughly one-third of the BAs' results fell into a higher risk category.

Method

The historical hourly demand and generation by BAA was averaged within each month to look at a typical daily shape across a month. The hourly demand was also averaged between 2019 and 2020 to reflect a potential future that blends pre-pandemic usage with an expectation of some amount of continued hybrid culture.

The 2025 and 2030 probability forecasts for hourly demand and generation were pulled from WECC's portion of the NERC 2021 LTRA.

The following factors were assessed both historically and through the probability forecasts:

- **Demand**—A day's hourly profile, averaged over each month;
- **Net solar**—A day's hourly demand profile, averaged over each month minus its average correlating hourly solar generation;
- **Net wind**—A day's hourly demand profile, averaged over each month minus the average correlating hourly wind generation; and

- **Net both**—A day's hourly demand profile, averaged over each month minus the sum of both the average correlating hourly wind and solar generation.

Next, for the 2025 and 2030 forecasts, demand was frozen at the 1-in-2, expected level or 50th percentile, meaning there were equal probabilities demand would be higher or lower than that amount for that given hour of the day. This was used to examine the bands of effects of 1-in-10 events, both on the low 10th percentile and on the high 90th percentile probability of the wind and solar hourly availability profile.

Finally, the BAs' results were categorized into high and low risk based on the slope of the ramps. A comparison of the variety of daily shapes is described below. Through historical event analysis, WECC determined the best months on which to focus for the Western Interconnection were:

- March and April, when demand is low and hydro generation is expected to be high during snow run-off periods; and
- August and September, typically the highest demand months for summer peaking BAs

In addition, wind capacity performs at its best in the spring and typically at its lowest in the late summer months.

Study Results

Current outlooks show the ramping issue is not expected to be a concern for most of the BAs in the interconnection. Future portfolios' resource type makeups could affect rates of ramping. Balancing areas that do not show future ramping risks within the study purview include:

- AESO Alberta
- Avista
- Arizona Public Service
- Balancing Authority of Northern California
- BC Hydro
- Bonneville Power (BPA)
- Mexico (CFE)
- Chelan County PUD
- Douglas County PUD
- Grant County PUD
- Northwest Montana
- PacifiCorp's Rocky Mountain Idaho and Wyoming territories
- Portland General Electric
- Puget Sound Energy
- Seattle City Light
- Turlock Irrigation District
- Tacoma Power; and
- Western Area Power Administration (WAPA) Colorado-Missouri and Upper Great Plains West.

A third of WECC's BAs, covering roughly half of the territory of the Western Interconnection, **do** show varying degrees of ramping concerns created by net demand. These BAs include:

- CAISO
- El Paso Electric Company
- Imperial Irrigation District
- Idaho Power
- Los Angeles Department of Water and Power
- NV Energy
- PacifiCorp East & West
- Public Service of New Mexico (PNM)
- Public Service Company of Colorado
- Salt River Project
- Tucson Electric Power, and
- WAPA Lower Colorado (WALC)

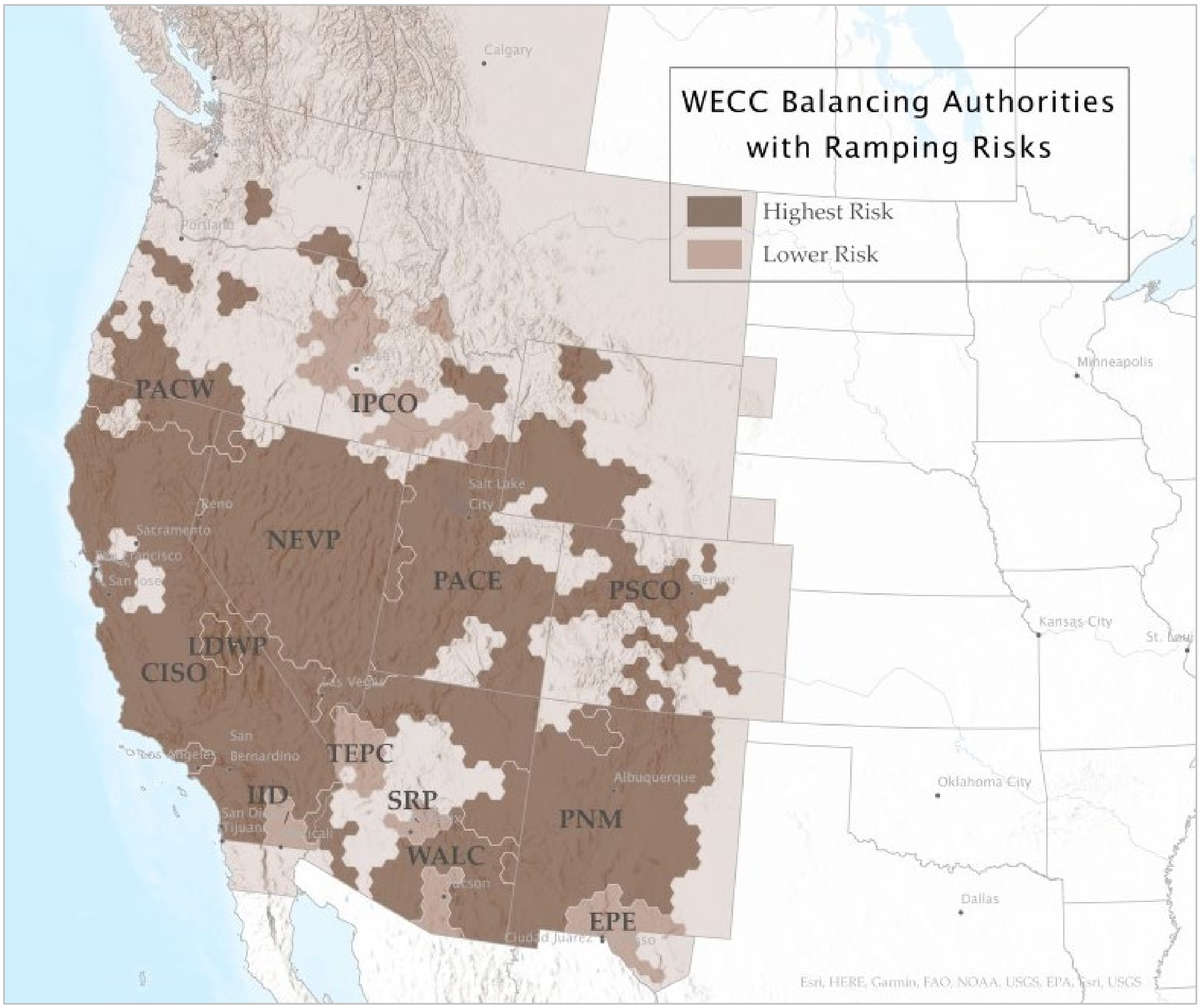


Figure 6: Map of ramping risks

Of the BAs showing varying degrees of ramping concerns, four were chosen to show examples of their unique potential for higher risk ramping. These include CAISO, which is planning to add further variable generation to meet the state's clean-air requirements and climate goals, mitigated by delayed natural gas peaking units' retirements and added energy storage through new utility-scale batteries which are expected to combat ramping issues by increasing flexibility through peak response. Many states and provinces across the West have forms of renewable generation targets or are implementing greenhouse gas emissions reduction strategies. These goals do not correlate with which BAs are showing ramping risks.

The other BAs selected as examples displaying a potential for extreme ramps include NV Energy, PNM, and WALC. Other BAs listed with ramping risk can be seen in Appendix A—Additional Ramping Curves.

The curves in Figure 7 through Figure 10 show an approximation of present demand with hourly wind and solar in the left-most column of graphs, and probability forecasts of the patterns for 2025 in the middle column, and 2030 in the right column, moving from March at the top row, down through April, August, and September on subsequent rows. The low lines represent the net demand under expected (50^{th} percentile, or 1 in 2) demand minus the 'low' 1 in 10 wind and solar availability (10^{th} percentile). The 'high' lines represent the net demand under expected demand conditions (50^{th} percentile still, or 1 in 2) minus the 'high' 1 in 10 wind and solar availability (90^{th} percentile). The expected demand minus the 1-in-2 (50^{th} percentile) of combined wind and solar generation would fall between the low and high lines. The results indicate afternoon ramps could increase as variable generation grows to fill a larger part of system portfolios.

California was the first subregion in the West to experience extreme ramp conditions. The CAISO will experience steeper afternoon ramps when solar output capacity dissipates in the late afternoon and demand is increasing as residential customers return home on weekdays (See Figure 7).

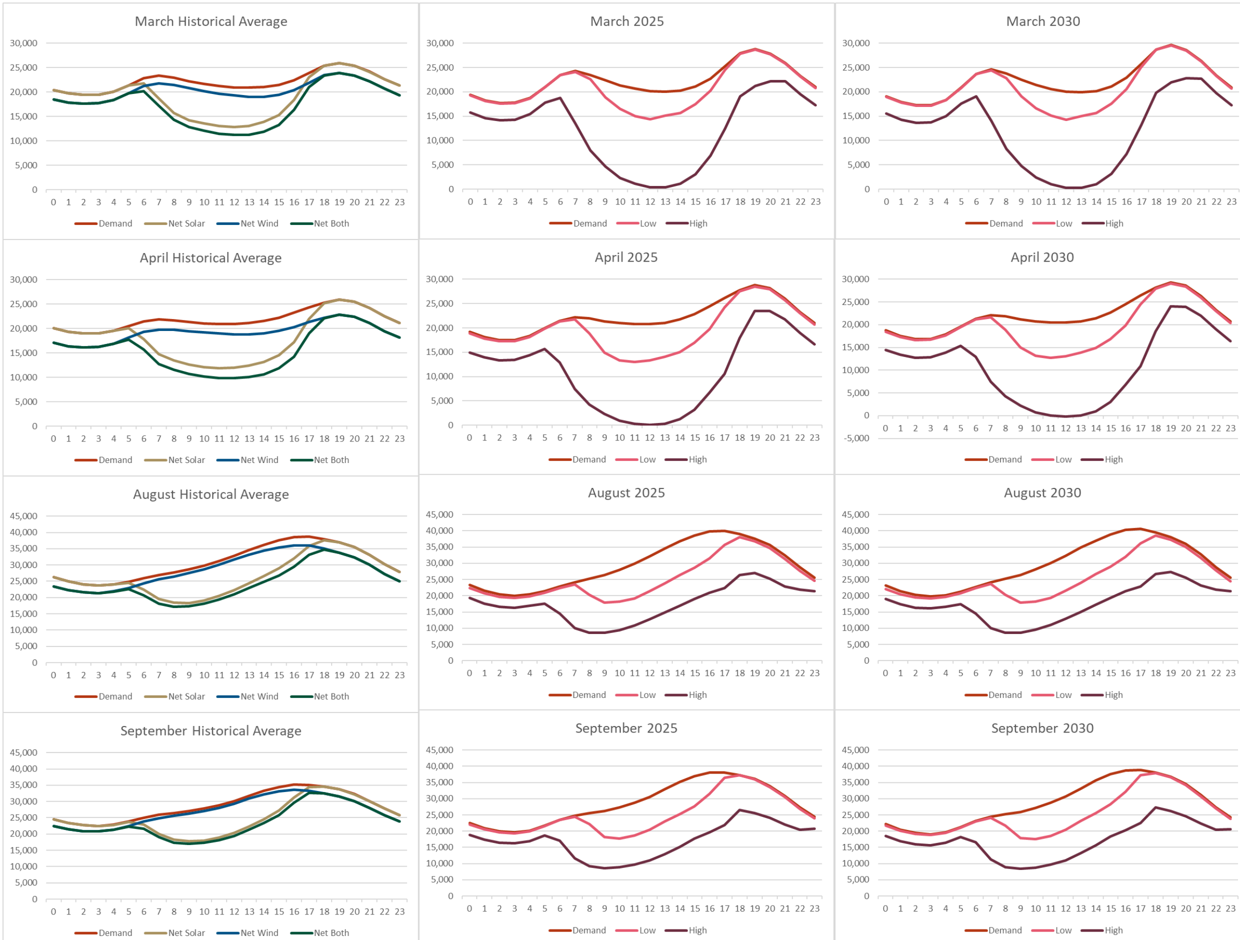


Figure 7: California ISO ramping scenarios

The results of the NV Energy BA analysis in Figure 8 demonstrate one of the more extreme cases of short-term ramping risk development in the interconnection. Under the 90th percentile (1 in 10 chance) of high solar and wind generation availability during the spring months, NV Energy would need to:

- Find neighbors to export surplus solar from 8:00 a.m. until 2:00 or 3:00 p.m. (times of negative values on the chart), or
- Curtail generation to maintain reliability, which forces negative pricing on occasions when renewables are abundantly available across the West.

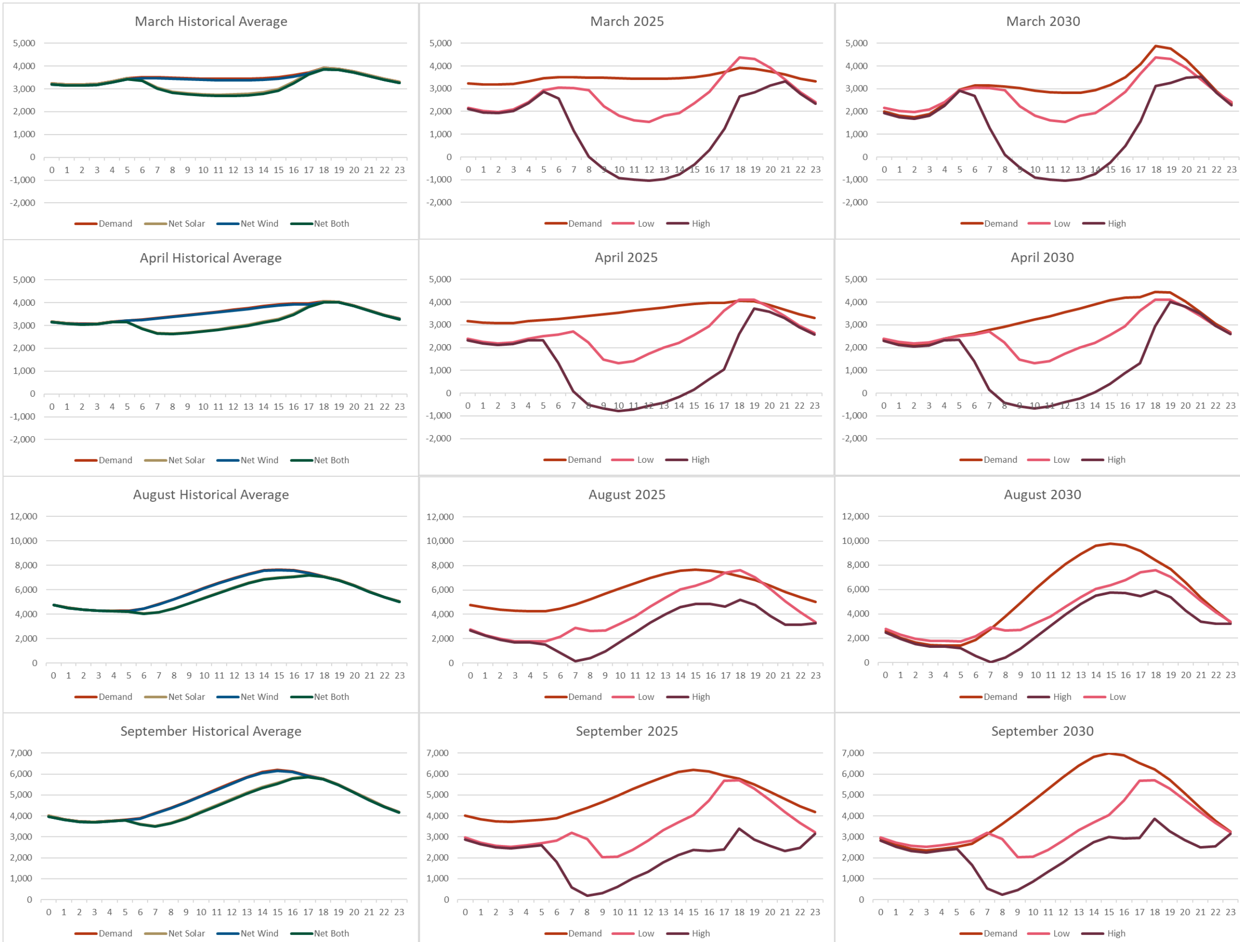


Figure 8: NV Energy ramping scenarios

In Figure 9, analysis of New Mexico's PNM shows a similar outcome of potential over-generation of solar during spring months for late morning to early afternoon hours, as well as in September, under the 1-in-10 likelihood, 90th percentile's high generation case, producing excess solar generation during the day that may need to be curtailed or exported to neighboring markets:

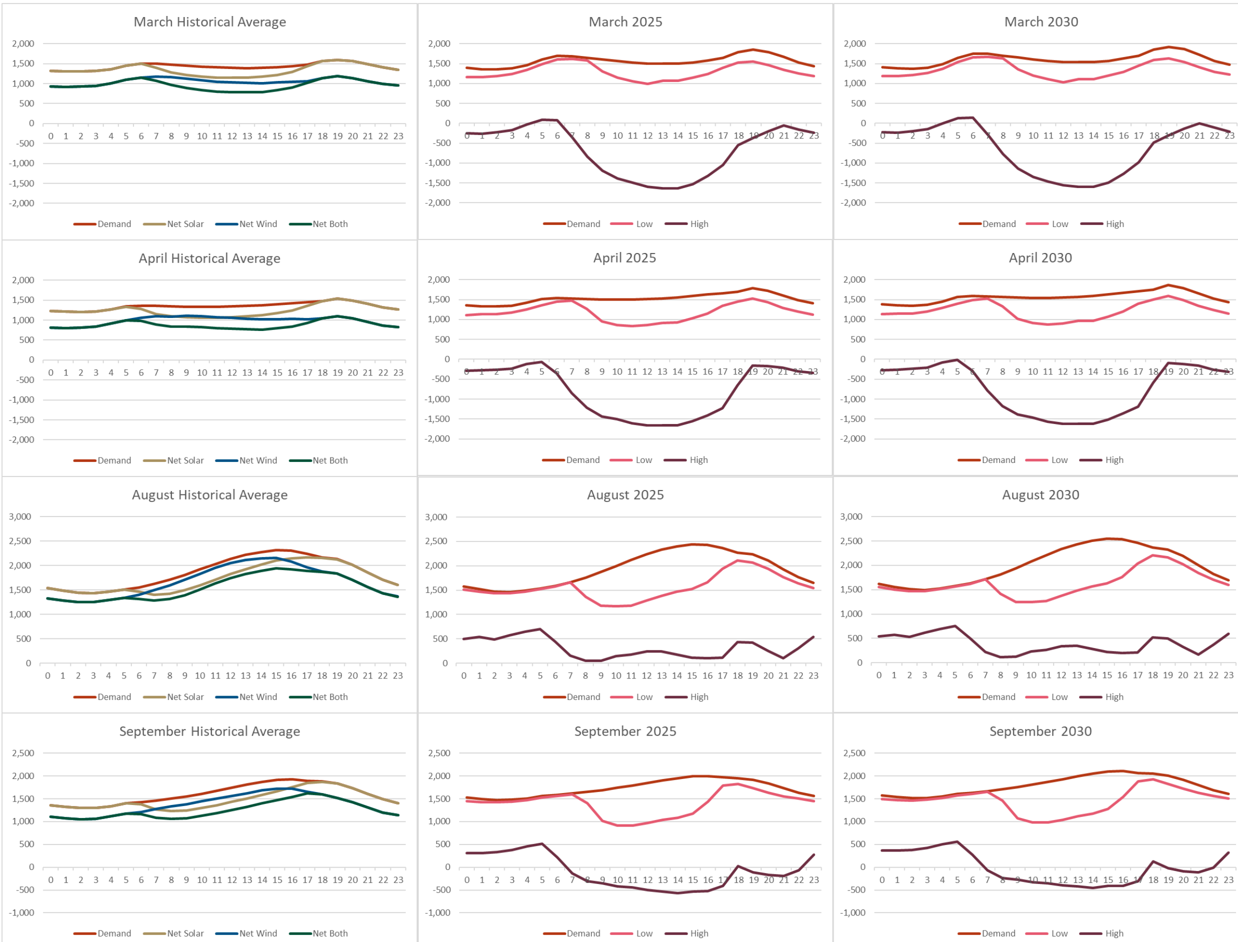


Figure 9: PNM ramping scenarios

Finally, the analysis of the WALC BA results, shown in Figure 10, provides another example of how the planned increased solar capacity could create new ramping risk. Under the 1-in-10, 90th percentile's high generation scenario, the risk of over generation develops during late morning through early afternoon.

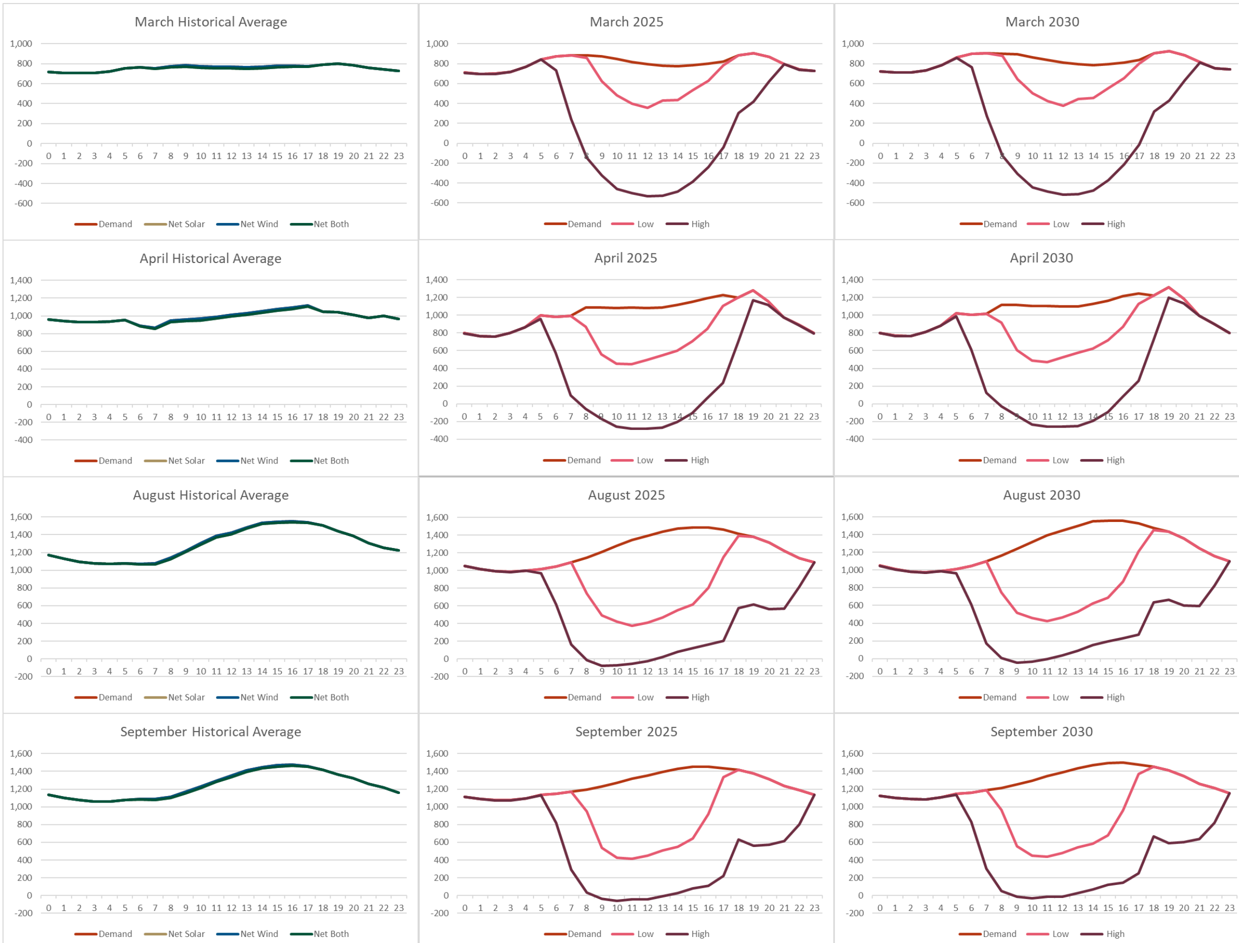


Figure 10: WALC ramping scenarios

Findings

In general, where resource portfolios have planned for the largest proportional increases in solar, steeper net demand ramping requirements are foreseen. The analysis of the curves shows the ramps happen most often during the late morning to early afternoon, sometimes skewed toward spring months when demand is low and solar generation has the potential to exceed local demand under the 1-in-10 likelihood of the 90th percentile's high generation availability scenarios.

Demand net wind does not show the ramping effect seen with solar capacity. This may be because wind can serve as a baseload resource if several wind farms are spread across a wide enough region and because of the increasing accuracy of their efficiencies. Similarly, systems more heavily reliant on hydro generation are expected to experience less of an effect from variable resource acquisitions.

Most BAs—about two-thirds—do not show potential future risk from planned increases in variable generation resource capacities. That said, as more variable generation is added to the BPS, entities will need to add sufficient flexible generation to respond to anticipated and unanticipated shifts in generation, along with to cope for wider demand swings due to extreme weather events and climate change.

Storage technologies such as pumped hydro, batteries, and some forms of hydrogen generation, with a range of capacities and durations, are part of solutions toward minimizing the impacts of variable resources on net demand ramping requirements and will be an important area of focus over the next few years (See Figure 11).

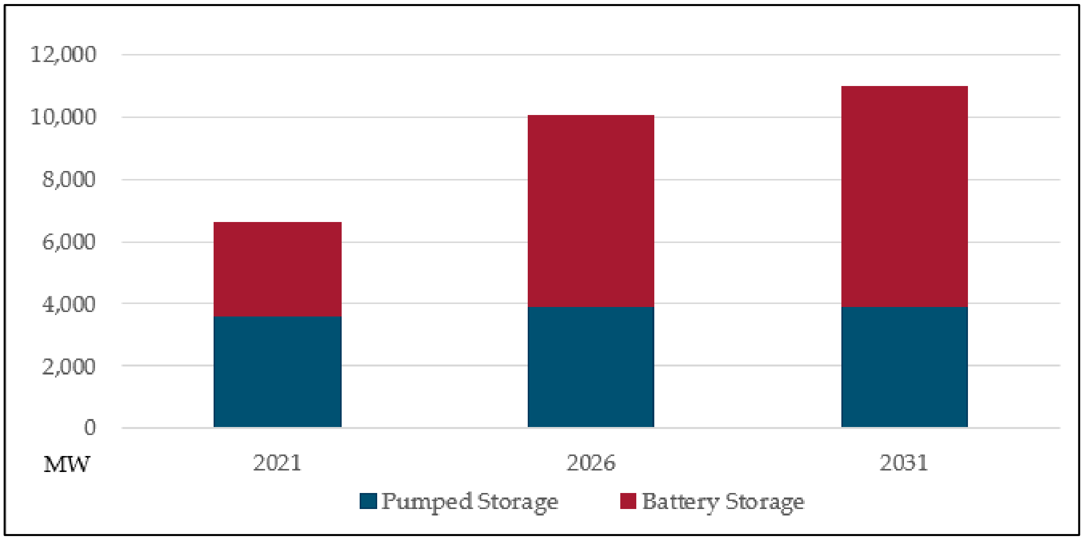


Figure 11: WECC anticipated energy storage levels

Significant amounts of new energy storage will be acquired and endure real-world testing over the next five years and through the end of the decade. In 2020, the West had 659 MW of battery storage (excluding pumped storage), 658.2 MW more than it had a decade ago.

Battery storage is expected to increase to 7,355 MW by 2030, 5,201 MW of which is planned to be installed by the end of 2023 (See Figure 12).

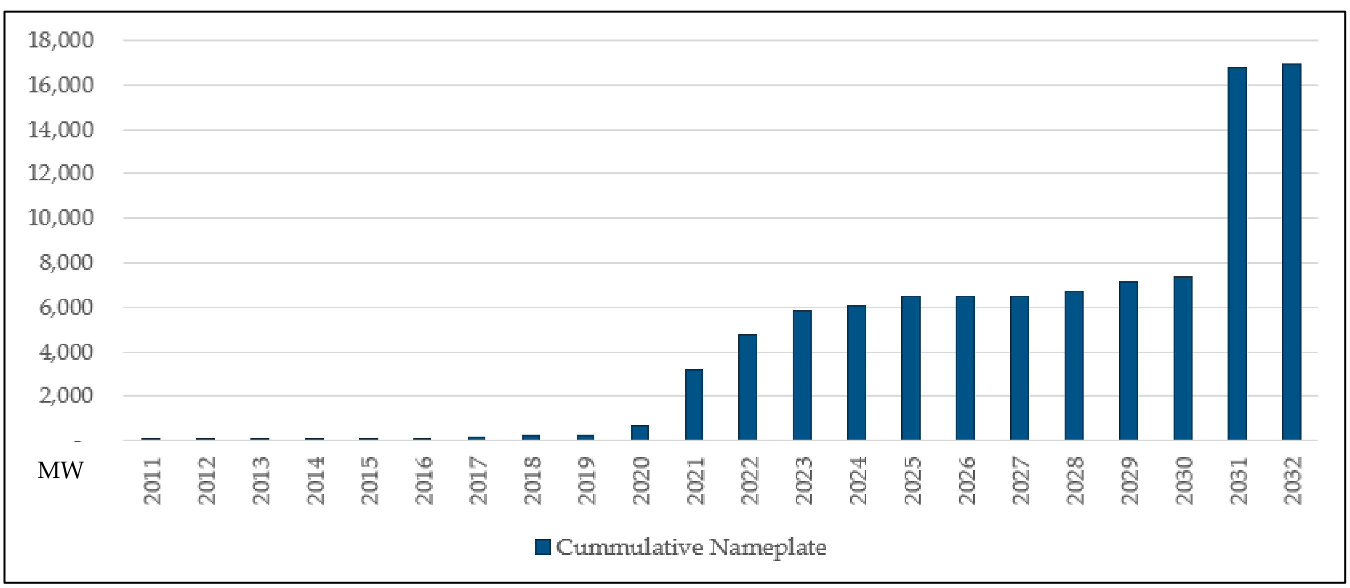


Figure 12: West's cumulative nameplate capacities of battery

The energy industry is ever evolving to meet new realities. The risk of variable resources having an impact on net demand ramping requirements is not negligible; however, technological solutions do appear to be ramping up to match the coming need to fill in the evening loads.

Chapter 3—Resource Adequacy

During the August 2020 Heat Wave Event, the CAISO experienced a shortage of generation and ordered rotating outages for the hours shown in Table 1. The August heat wave lasted from August 14 through 18, but steps were taken to avoid rotating outages during the last four days. A similar heat wave occurred from September 4 through 7 with no rotating outages.

Table 1: CAISO 2020 rotating outages

Date	Start Time	Duration	Amount
8/14/2020	6:38 p.m. (Pacific Time)	~1 hour	1,000 MW
8/15/2020	6:28 p.m. (Pacific Time)	20 minutes	500 MW

The following paragraph from the joint California *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave Report* supports the concern raised by FERC:

> The rotating outages both occurred after the period of gross peak demand, during the "net demand peak," which is the peak of demand *net of solar and wind generation* resources. With today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. This is because air conditioning and other load previously being served by solar comes back on the bulk electric system. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability, and this challenge is amplified during an extreme heat wave.[3]

Figure 13 shows an example of these transitions for the CAISO with the output of Solar PV rapidly decreasing each day between hours 16 and 20. Other resources, such as thermal fossil, hydro, and imports, must quickly ramp up to meet the load. Often, the wind picks up around dusk and wind generation helps with the ramp.

[3] Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave Report, page 4.

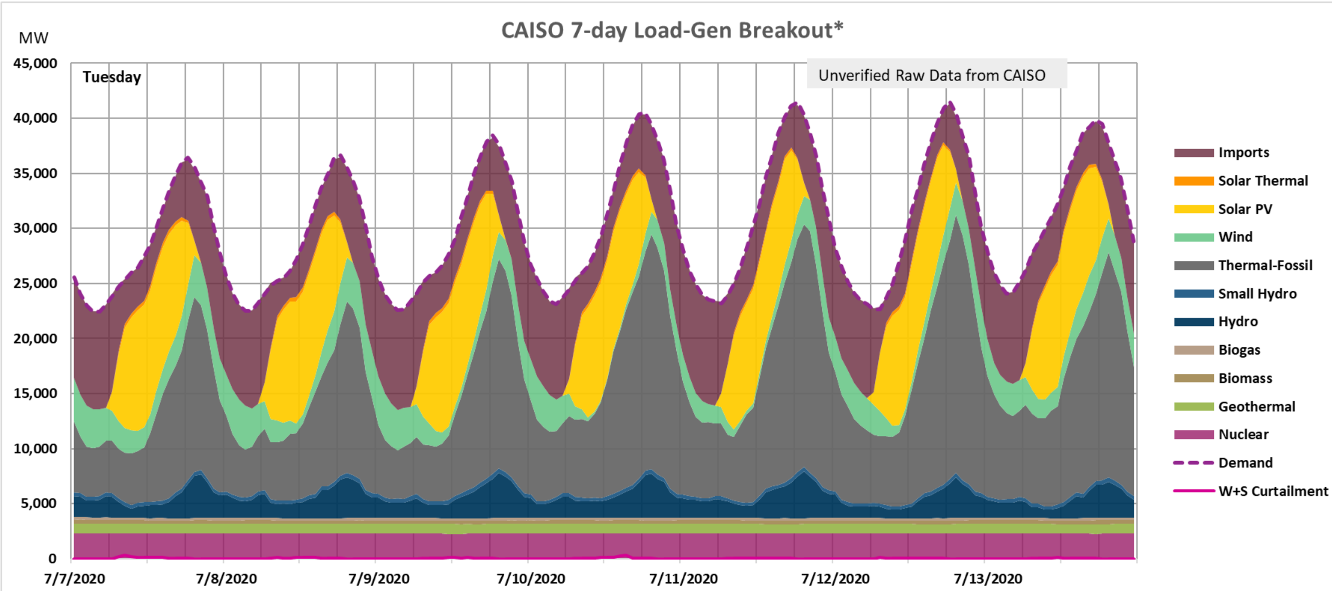


Figure 13: Sample CAISO summer dispatch

Production Cost Model Analysis

The proposed scope for the analysis includes the use of a PCM to study the Western Interconnection in the future, focusing on 2025 and 2030. The PCM is a tool that can be used to perform deterministic, or static, studies of resource adequacy. The demand and generation inputs are specific to the case being studied, usually an average or 1-year-in-2 scenario. WECC recently completed its 2030 Anchor Data Set (ADS) PCM case (2030 ADS PCM version 2.3 or 2030 ADS case), which was created using data from the 2030 Heavy Summer Power Flow case and the Loads and Resources Data collection process. A slightly modified 2030 ADS case was used for the VER 2030 PCM study and then adjusted to perform the VER 2025 PCM study. Generation adjustments and variables that affect the PCM are detailed in Appendix B—Generation Adjustments and Variables.

Two scenarios were studied for each of the 2025 and 2030 cases: the base scenario, in which expected demand was compared to expected generation availability, and a stressed scenario, in which all units at the Palo Verde Nuclear Plant were unavailable during August. The results from both studies were used to evaluate the following items:

- Unserved load;
- Transmission congestion;
- Regional interchange;
- Generator capacity factors;
- Curtailment of renewables; and
- Ramping requirements during transitions from high solar output to low solar output.

VER PCM Study Results

Two PCM studies were run for the VER 2025 study: the base scenario—VER 2025 v01—including the changes noted in Appendix B—Generation Adjustments and Variables, and the stressed study—VER 2025 PVoutinAug—with all three Palo Verde Nuclear units unavailable during the month of August.

Unserved Load

The results of these two studies indicate that, for both the 2025 scenarios, the system is resource adequate given expected load and resource availability, and there was no unserved load in either case.

Regional Interchange and Path Utilization

Figure 14 shows the regional interchange results. There were small changes at several ties to cover the lost generation from Palo Verde.

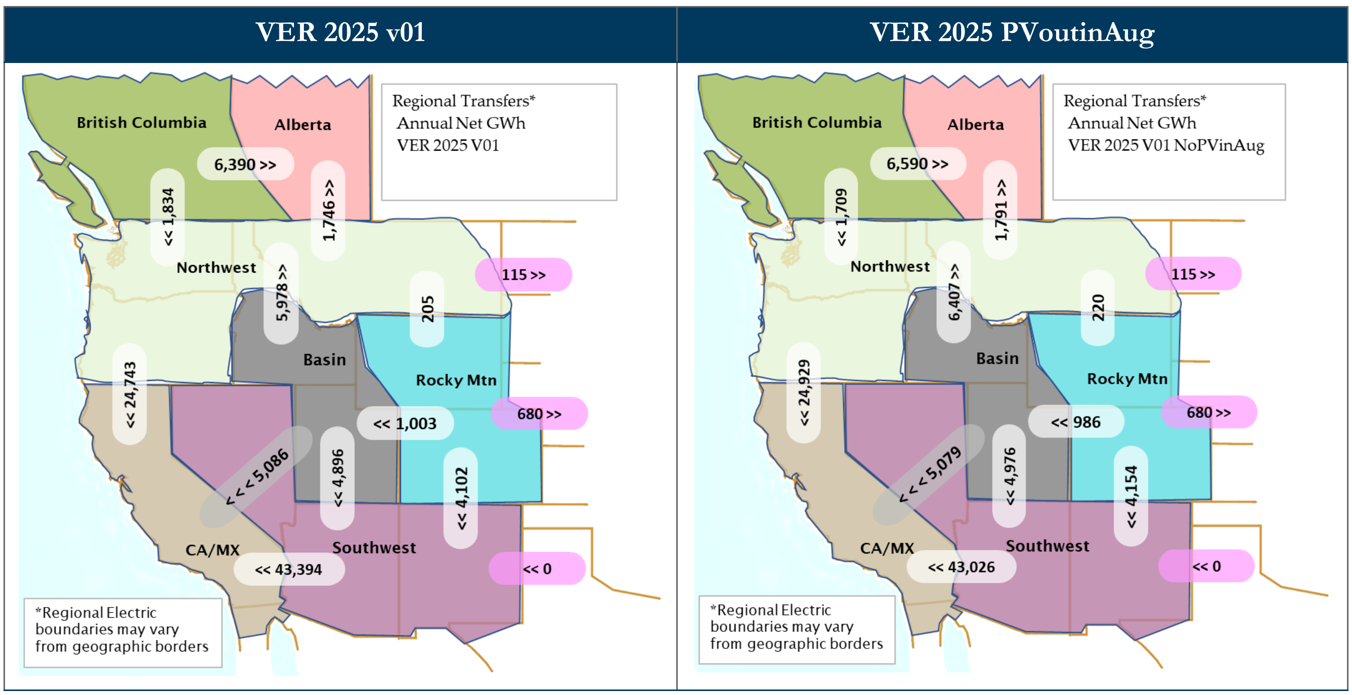
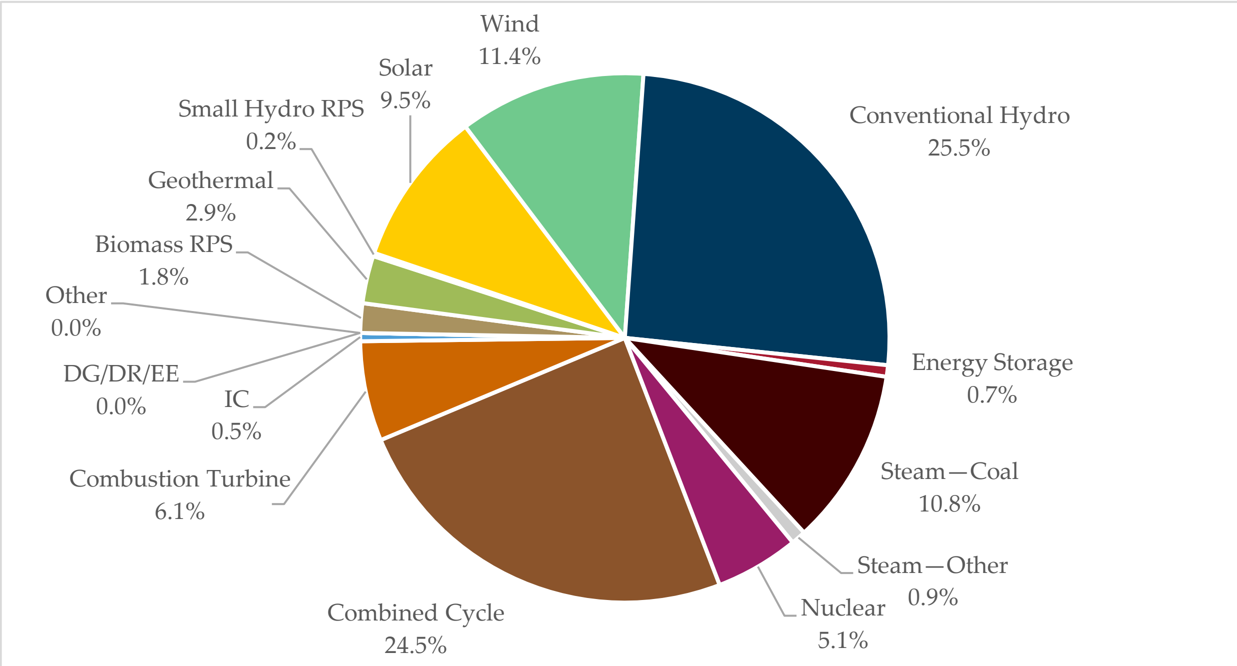


Figure 14: Regional interchange comparison

Generation Dispatch

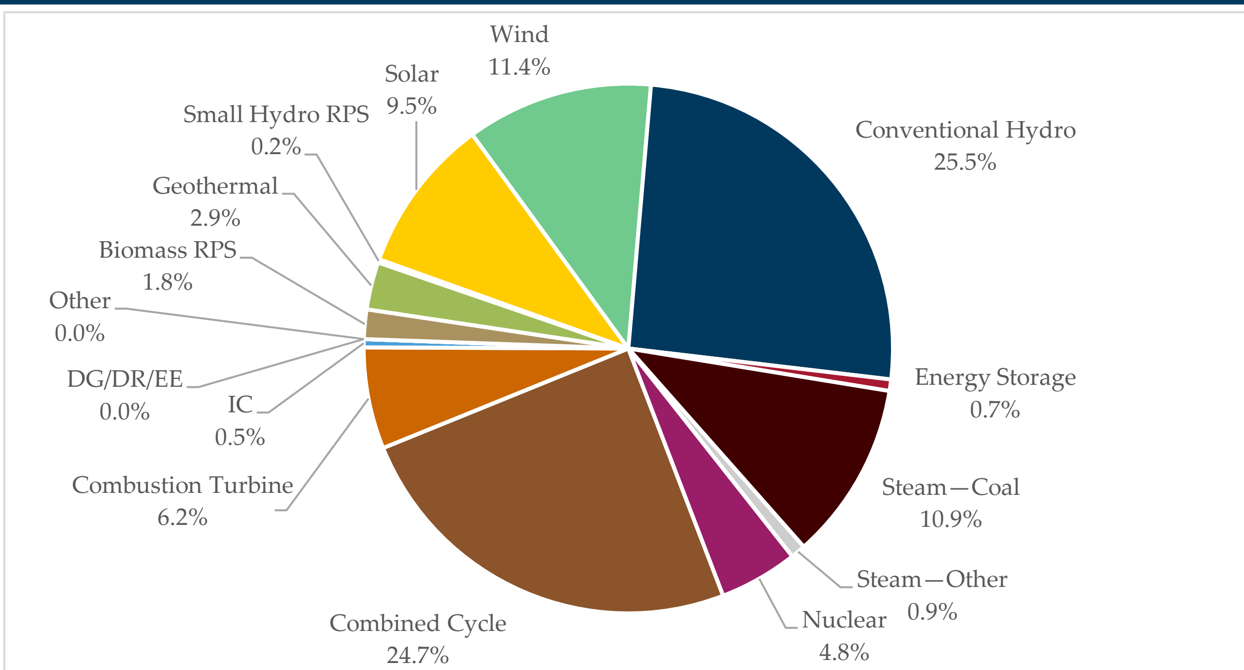
The annual totals of the hourly generation dispatch provide information about which generators are used to meet the load requirements in the two VER 2025 cases. The results show that the interconnection is expected to have enough flexible generation to meet the load requirements and balance the variable generation. Figure 15 compares the percentage breakdowns by generation type.

VER 2025 v01



Annual Generation Total = 937,990 GWh; Renewable Contribution = 25.8%

VER 2025 PVoutinAug



Annual Generation Total = 938,035 GWh; Renewable Contribution = 25.8%

Figure 15: Generation results for VER 2025 cases

Since the base loads did not change, the slight increase in annual generation is likely due to differences in the transmission losses and the charging dispatch of energy storage resources.

VER 2030 Study Results

Two PCM studies were run for the VER 2030 study, one with the changes noted above—VER 2030 v03a—and a second study with all three Palo Verde nuclear units unavailable during the month of August—VER 2030 PVoutinAug.

Unserved Load

There were a few hours with some unserved load in the VER 2030 PVoutinAug case on August 19, as shown in Figure 16. The highest amount, 1,382 MW, was on hour 19.

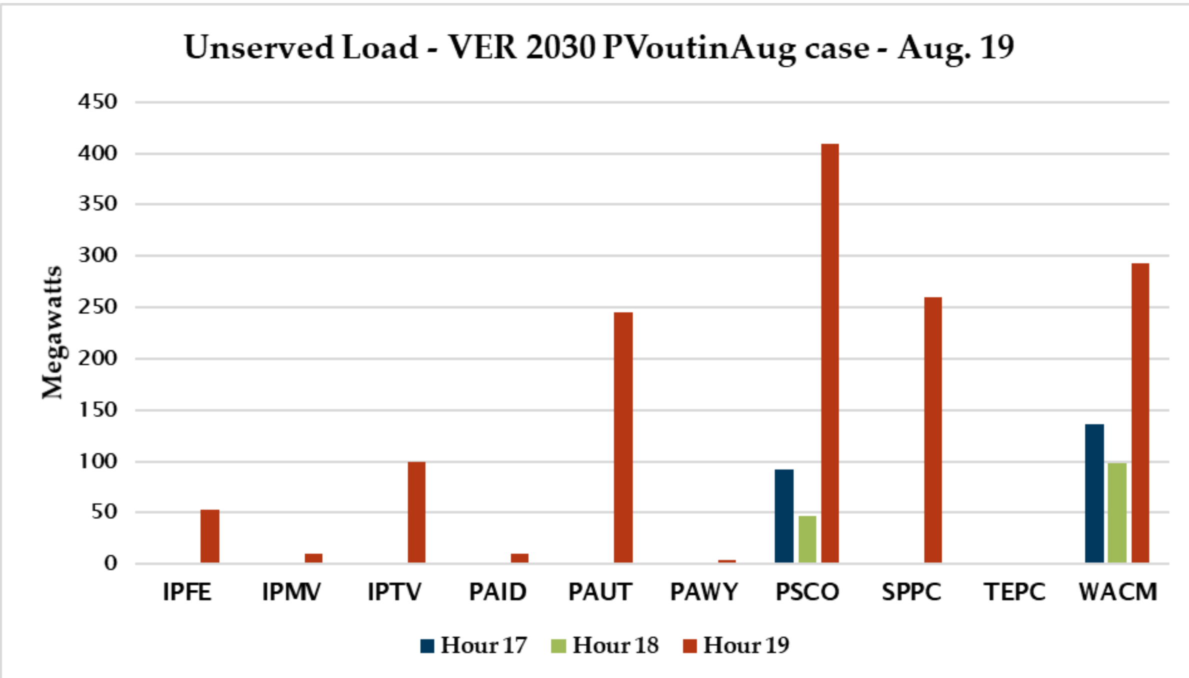


Figure 16: Unserved load in VER 2030 PVoutinAug case

Research into the cause of the unserved load found that several generators were on forced outage, and several paths were at their limits. Also, all three units at Palo Verde Nuclear Generating Station were unavailable per the sensitivity case assumption.

Regional Interchange and Path Use

Figure 17 shows the regional interchange results. The one-month outage of Palo Verde in August prompted a few changes in the regional interchange, including an increase in flow from the Basin region to CA/MX.

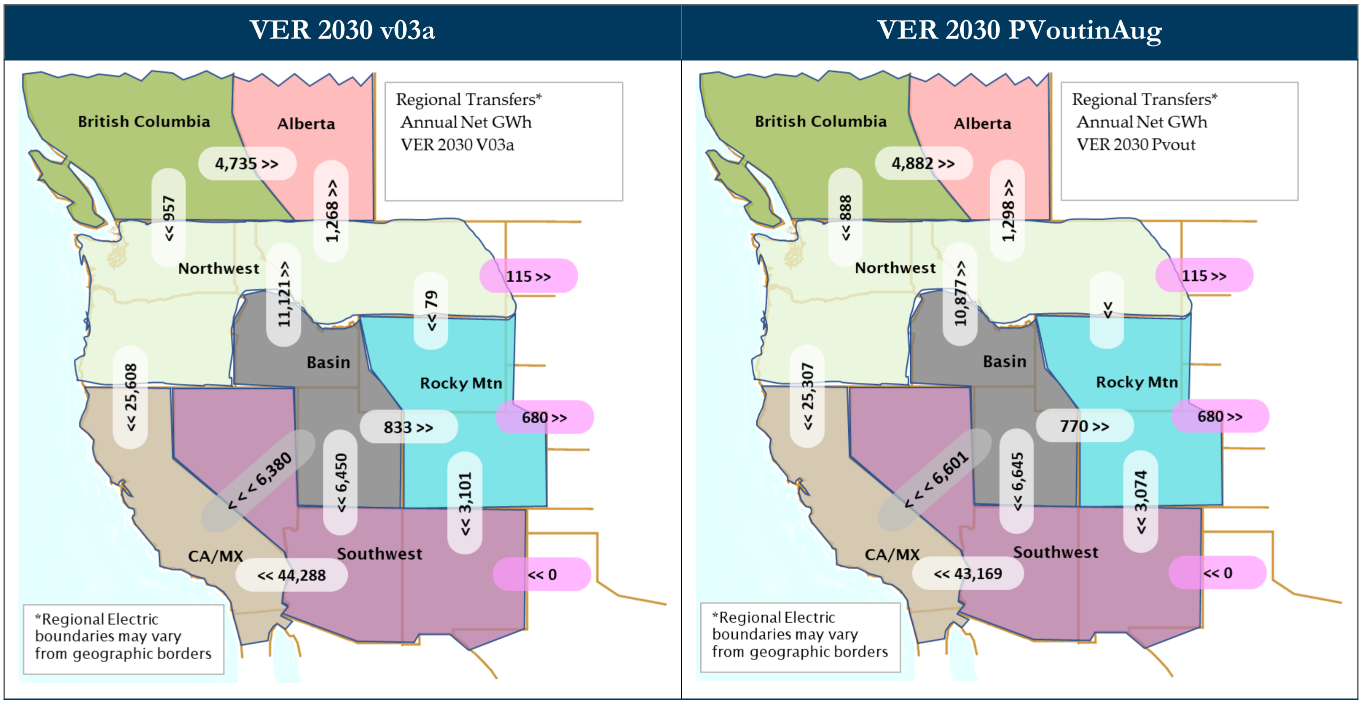


Figure 17: VER 2030 regional interchange

Generation Dispatch

The PCM solves each hour of the case to serve the load at each bus at the lowest overall cost, subject to all the defined constraints. Figure 18 shows the annual generation differences by resource type for the VER 2030 cases and shows combined-cycle and combustion turbine units filling in for the unavailable Palo Verde Nuclear units.

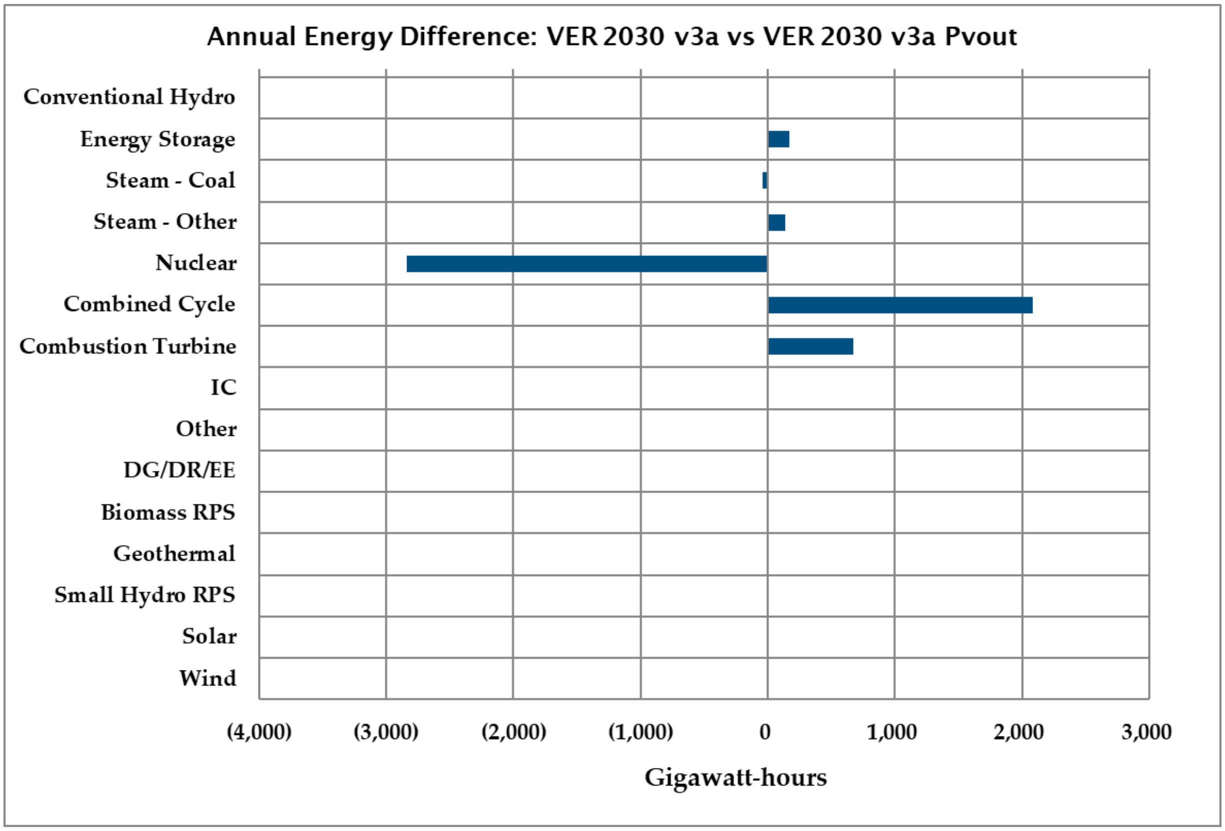


Figure 18: Change in generation among 2030 cases

Hourly Analysis

The WECC coincident peak hour in the first case is on hour-ending 17 of August 20, 2030. Although solar generation helps to serve the peak load, a large amount of conventional generation is needed to meet the high summer loads.

Figure 19 shows the generation shares for the peak hour (Mountain Time). Fossil-fueled generation is the primary source, at just over 50%.

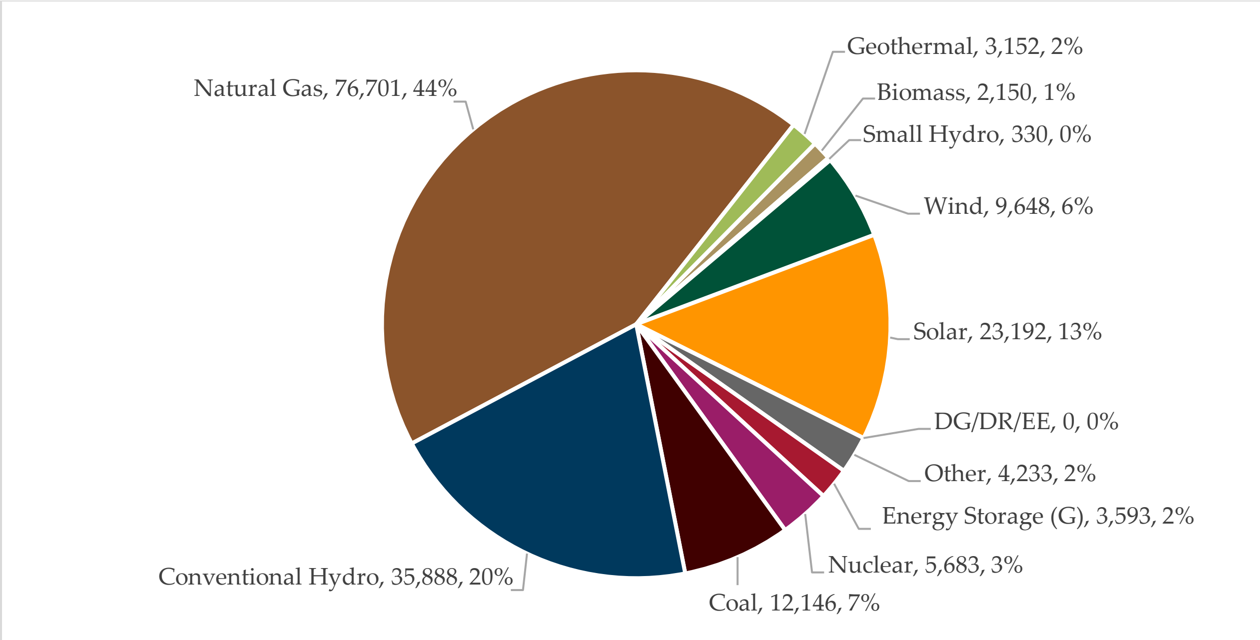


Figure 19: Peak hour generation breakout

Many states and provinces in the Western Interconnection are planning to reduce their reliance on fossil fuel by increasing their shares of renewable generation and battery storage. New plans are announced every year, and changes to the 2030 resource mix will be submitted to WECC as the plans move forward.

Comparisons of the VER 2025 and VER 2030 PCM Studies

One reason for preparing studies for two different years was to look for trends in how the load requirements are met and to look for ramping problems in each year.

Generation

Figure 20 compares the annual generation breakdown for the VER study cases. The thermal generation retirements and higher load (+4%) in the 2030 case were balanced by renewable additions and higher dispatches of combined-cycle and combustion turbine units.

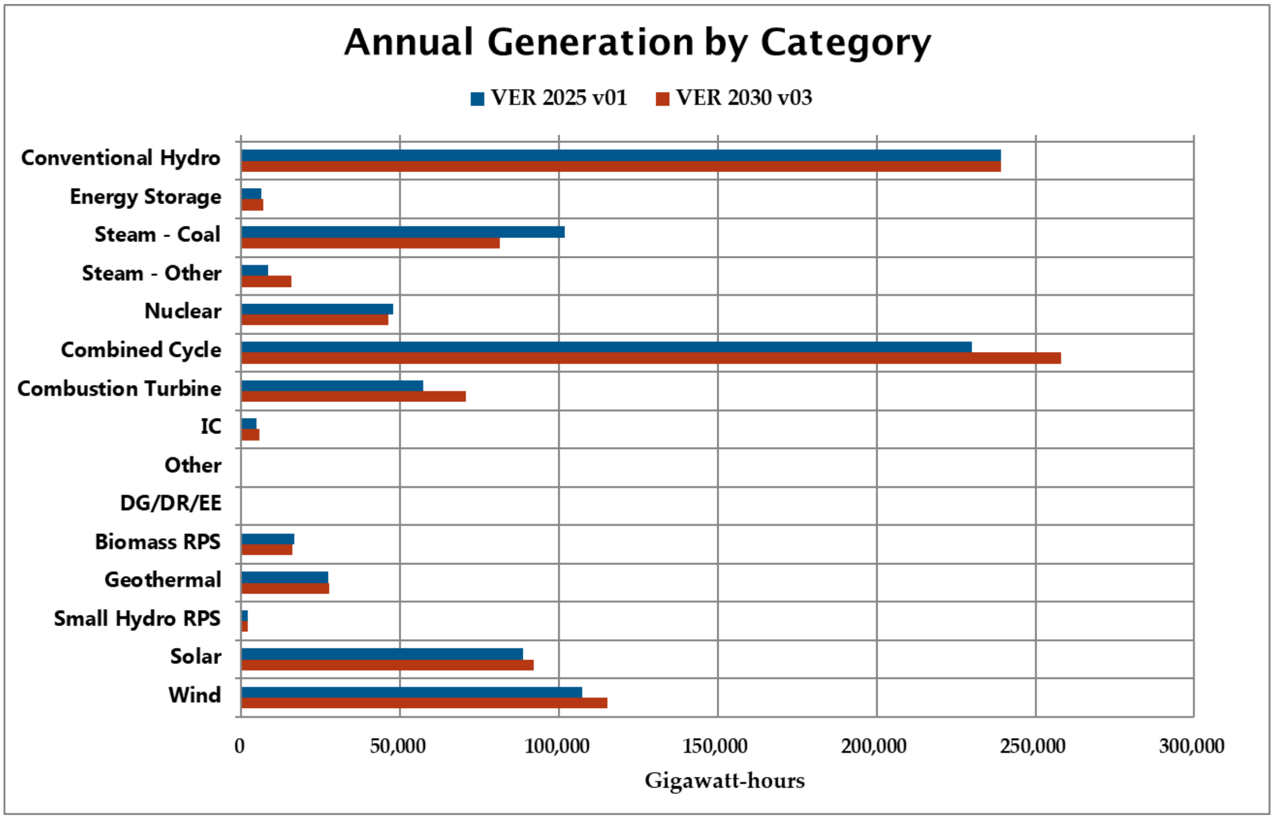
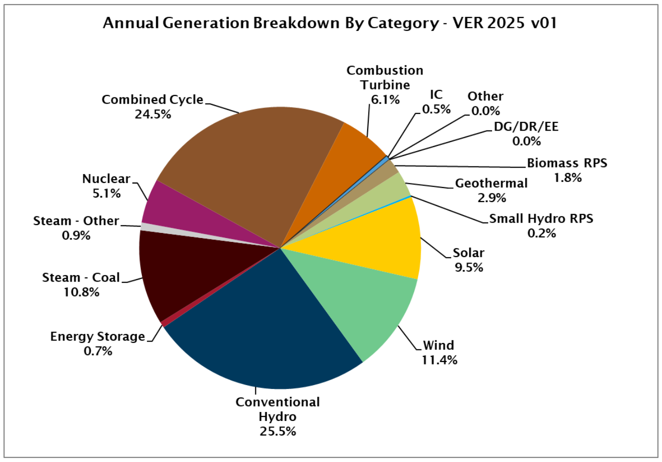


Figure 20: Comparison of annual generation by category

Figure 21 shows the generation breakdown comparison, which reveals that the breakdown for the Western Interconnection overall had little change. Figure 22 shows how the generation breakdown changed in the various subregions.

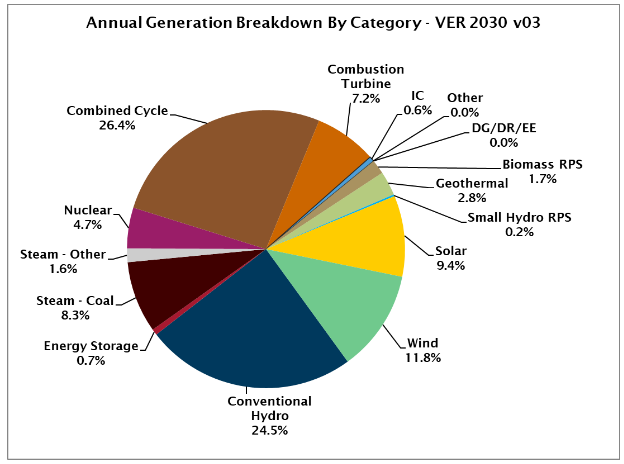
VER 2025 Study



Annual Generation Total = 937,990 GWh

Renewable Contribution = 25.8%

VER 2030 Study



Annual Generation Total = 976,854 GWh

Renewable Contribution = 25.9%

Figure 21: Annual generation comparison

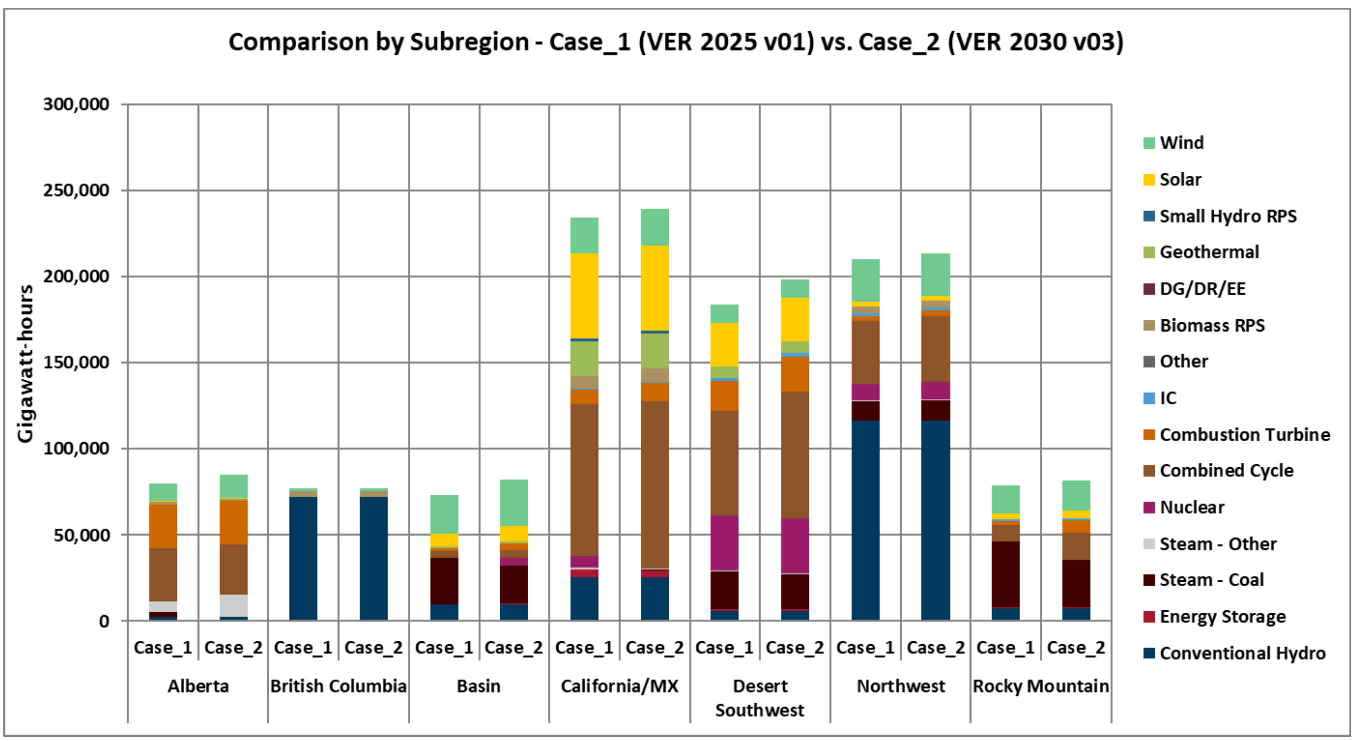


Figure 22: Annual generation comparison by subregion

Interchange and Path Flow Comparisons

The regional interchange net annual values show where energy is flowing in the Western Interconnection based on the inputs for the PCM studies. Figure 23 shows the results from the VER 2025 study and the VER 2030 study. Here are a few highlights:

- The annual imports into California are higher in the 2030 study than in the 2025 study. A few of the contributing factors include:
  - The retirement of Diablo Canyon Unit 2 in August 2025; and
  - Generation expansion in neighboring regions.
- The surplus in British Columbia is likely higher in 2025 than in 2030.
- The surplus in the Basin region is higher in 2030 than in 2025. One reason for this is the scheduled construction of the Antelope Modular Nuclear Power Facility in Idaho with a modeled in-service year of 2027.[4]

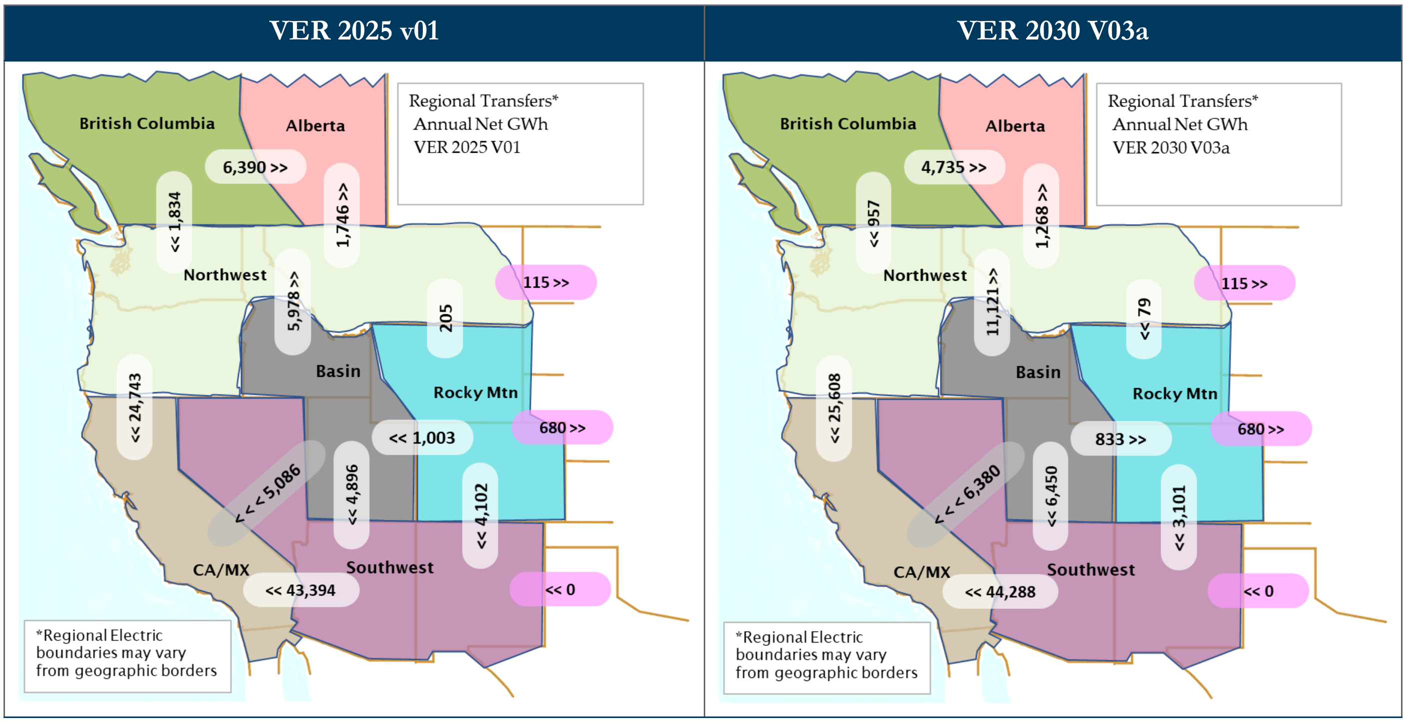


Figure 23: Comparison of regional interchange

PCM Observations

Net Demand

Net demand is the demand minus solar and wind output in areas that have a high penetration of solar and wind generation. As shown in Figure 24, the shape of the net demand curve, or ramping curve, is mostly due to the daily output shape of the solar with its late start in the morning and early exit in the evening. As identified and discussed in chapter 2, demand minus solar and wind can lead to a steep ramping requirement for non-solar resources at sunset.

[4] The planned Antelope Modular Nuclear Power Facility is modeled as a 587 MW, 12-unit project in these studies. A recent announcement reported that it will likely be downsized to a 460 MW, six-unit project.

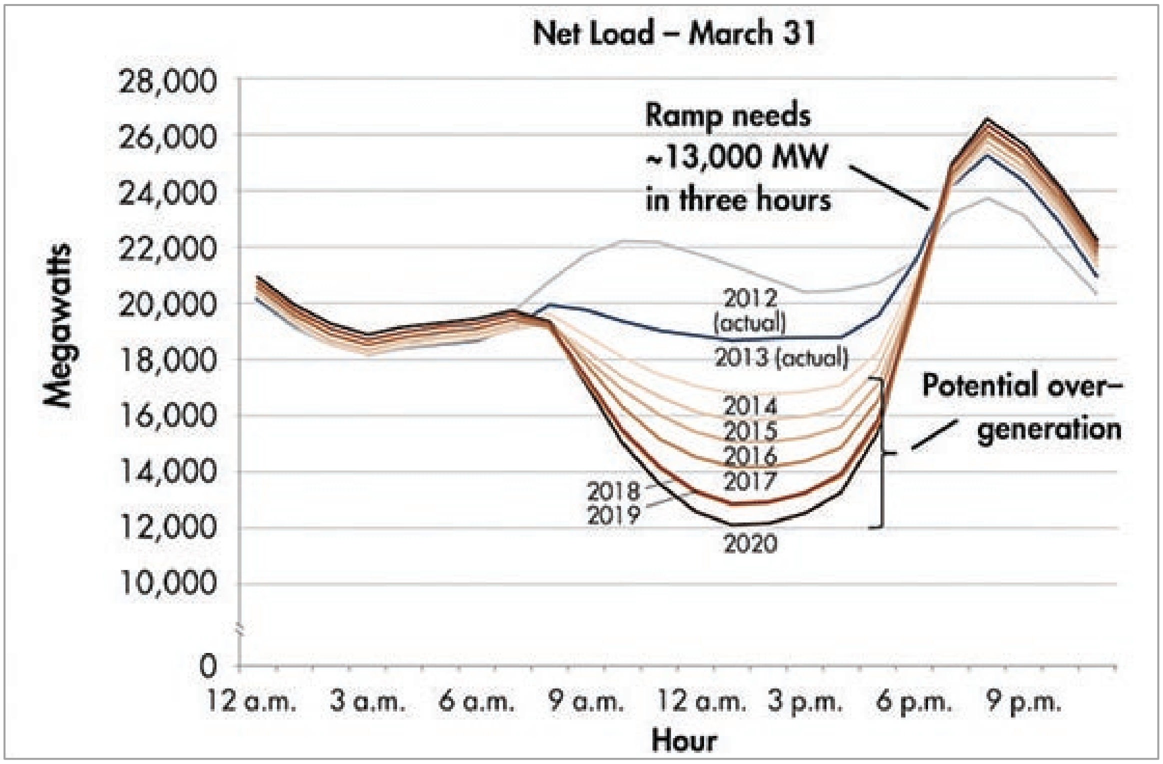


Figure 24: Ramping curve example

The CAISO recently experienced a three-hour evening net ramp of 17,259 MW, and ramps between 10,000 and 16,000 MW have become the norm. Figure 13 on page 27, gives an idea of how the ramps are managed using mainly natural-gas-fired generation.

By 2030, there will certainly be other BAs figuring out how to deal with steep demand ramps, and fossil fuels may not be the preferred resource type. Load-serving entities are procuring more environmentally friendly dispatchable generation such as energy storage and perhaps hydrogen. The evening net ramps could also be affected by other factors such as:

- Behind-the-meter (BTM) rooftop solar: Influences the ramping curve and net ramp in the same way that utility-scale solar PV does.
- Battery energy storage systems (BESS): Ideally, these would reduce the ramping curve ramp by using surplus solar and wind resources to charge in the midday and then generate and discharge during the ramp and peak. BESS is not as helpful during the summer months since solar and wind are needed to serve the air conditioning load. There will also be times when the wind is not blowing and the sun is blocked by clouds.
- Electric vehicles: As the number of electric vehicles increases, the number of owners who choose or need to charge their batteries between 5:00 and 9:00 p.m. will increase. This directly affects the ramp and peak.

- Building electrification: If building heating switches to electricity, the winter demands will increase and likely affect the ramp and peak.

The VER PCM studies discussed in this report did not show any obvious problems with California's ability to meet the ramping curve. Figure 25 shows the CAISO dispatch from the VER 2030 study for a period in April 2030, in which the CAISO combined-cycle, hydro, energy storage, imports, and often wind generation were able to ramp up as the solar generation rapidly ramped down each day. Note that the blank space between the generation and demand represents the imports. The imports may be contractual or economic and may have some flexibility (See Appendix B—Generation Adjustments and Variables for information about joint plants and contracts).

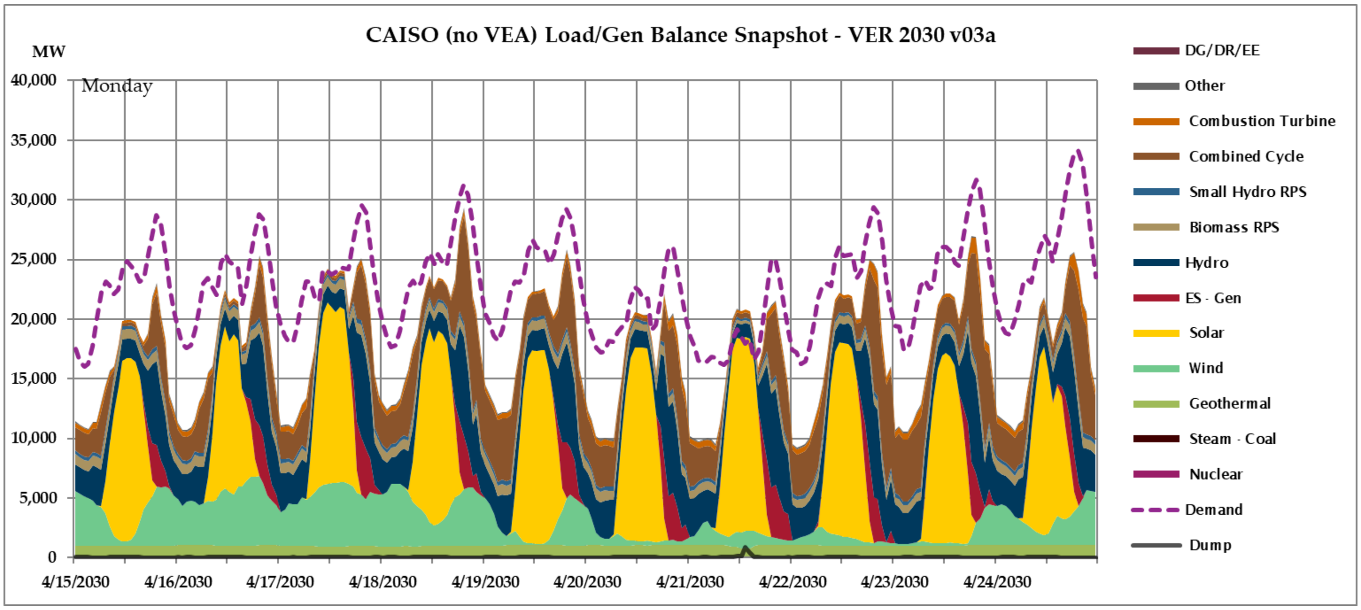


Figure 25: CAISO dispatch—VER 2030 study

Figure 26 shows the results for the period in September 2030. The main difference in this chart is the increased dispatch of combustion turbine generators to assist with higher loads and the ramping curve. The peak hour for the CAISO in this study case is on September 6 on hour ending 17. The ramping curve would be more intense with more solar generation.

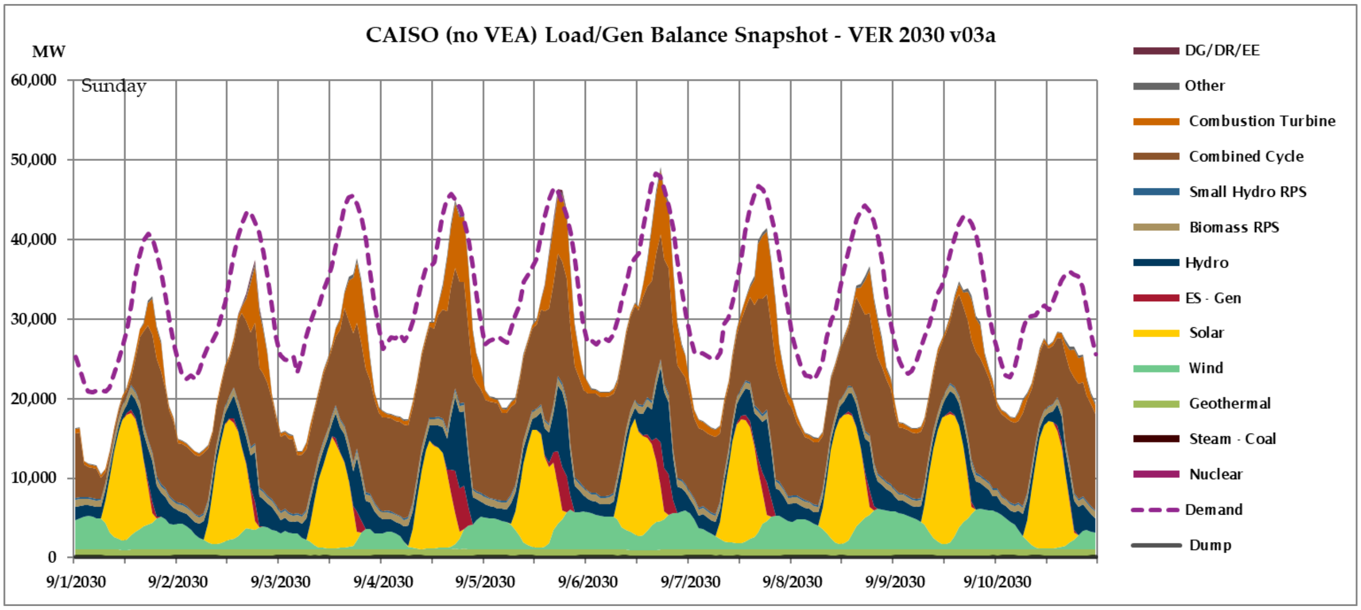


Figure 26: CAISO dispatch from VER 2030 study (September)

Figure 27 shows the net load ramps (net load solar and wind) for the same period with high, five-hour ramps between 12,200 and 21,000 MW, but more moderate three-hour ramps between 9,560 and 13,840 MW.

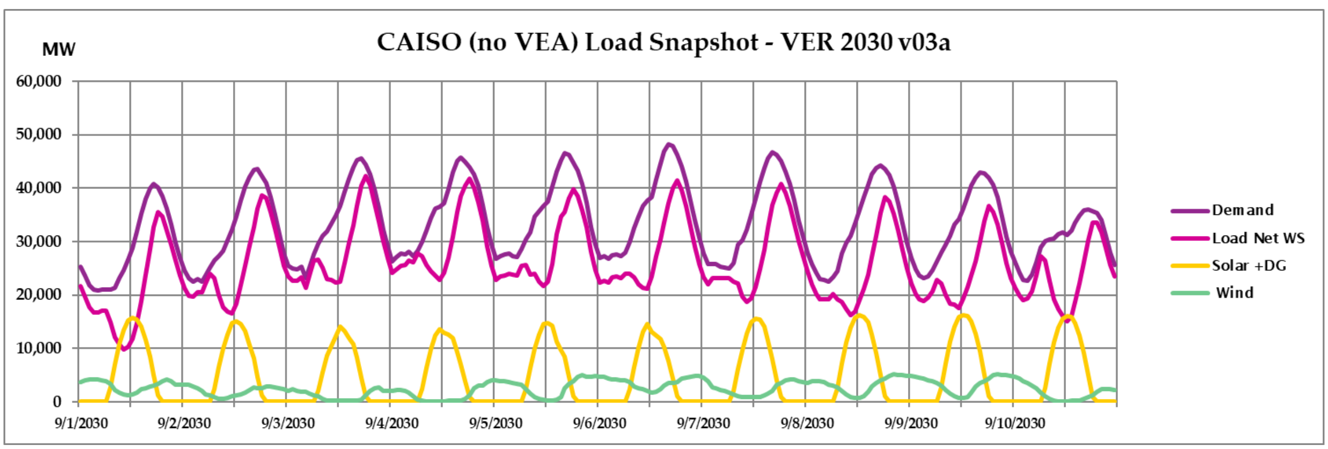


Figure 27: CAISO load net wind and solar example

Findings

Four scenarios were studied to identify potential generation shortfalls in full-year hourly studies. The four studies served to identify any problems meeting peak demands, reserve requirements, and balancing the steep ramps associated with the net-of-solar ramping curves, or "solar transitions."

There was no unserved load in cases 1, 2, and 3; however, a few areas in Idaho, Utah, and Colorado had unserved load in case 4 on August 19, 2030, during hours 17, 18, and 19. The unserved load occurred during the evening solar transition with other contributing factors, including generation outages, transmission congestion, and the simulated three-unit outage of the Palo Verde nuclear plant.

The studies show that future resources are expected to be adequate for the expected or average demand and resource availability scenario, but only if they are added to the grid as planned and reported to WECC. High demand or low resource availability scenarios were not considered in this study, but as identified in the Western Assessment of Resource Adequacy, it is expected under extreme conditions areas would not be resource adequate.

The study also identified that flexible generation resources may be needed to maintain the reliable operation of the BPS as more variable resources are added to the grid. However, the study does not include intra-hour demand and generation variability, which can have a strong effect on resource adequacy. Studies looking into intra-hour ramping and resource variability would provide a more detailed assessment of resource needs.

The final important finding from this section is the importance of using probability models when performing resource adequacy studies. As more variable resources like wind and solar are added to the grid, the variability in the availability of generation increases. Probabilistic studies look at a range of possible scenarios and test many combinations of demand and generation. Although the results of this set of studies indicate the interconnection should be resource adequate for the expected or average demand and resource availability scenario, under different assumptions, the results may be different, and probabilistic studies would identify those conditions. Results from the latest probabilistic studies that WECC conducted can be found in the Western Assessment of Resource Adequacy.[5]

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[5] Reliability Assessments Home (wecc.org)

Chapter 4—Control Performance Standards

This chapter explores how the changing resource mix or other factors affected CPS1 scores, in the hope of ultimately providing insights about whether current CPS1-monitoring protocols are adequate for a system with an evolving resource mix or load.

Changing generation resources and market structures have raised questions about the adequacy of existing measures for system control performance. CPS1 is one measurement of how much a Balancing Authority Area (BAA) or BA is over- or under-producing electricity relative to the rest of the interconnection. These values are calculated continuously and reported monthly. Actual generation by a BA at any moment is the result of many decisions by many people, shaped by such diverse factors as reliability, economics, fuel availability, and corporate philosophy. The relationships between hourly CPS1 and potentially important variables such as renewable generation have so far proven too subtle and complex to be captured with classical statistical modeling.

This analysis attempted to use random forest machine learning to model the effect of variable generation and Energy Imbalance Market (EIM) participation on hourly CPS1 values (See Appendix C—Generation Adjustments and Variables). In contrast to classical statistical modeling, random forest machine learning relies on exhaustive computer search of sequences of decision-variables to identify relationships that would not be detected through human inspection. Such a model would allow testing hypotheses about what CPS1 values would be under conditions of more or less renewable generation, or different EIM participation status. Because the random forest technique is so good at finding patterns, there is some danger that the technique will find patterns that only mimic the idiosyncrasies of the training dataset without reflecting reality in general. To guard against this outcome, a common technique is to initially divide data into two portions: a training portion and a testing portion. After a model is developed with training portion, the model is tested with the testing portion. A model that performs well with the testing portion is deemed to credibly describe reality, whereas a model that performs badly with the testing portion is said to be "overfitted." An over-fitted model – regardless of how impressively performing with training data – cannot be trusted to describe anything beyond the training data.

The dataset used for this analysis was limited to those BAs with the fixed bias settings necessary for calculating CPS1. In addition, generation-only BAs were removed because the concept of balancing load and generation does not apply. This left 27 BAs for which a random forest model was constructed to assess the effect of wind and solar generation on hourly CPS1. Another model of five BAs was used to assess the influence of EIM participation.

Wind and Solar Analysis

Broad experimentation suggested that the following variables might be somewhat useful for estimating hourly CPS1 scores. (Some variables were normalized by each BA capacity, as noted below.)

- BA
- BA hourly demand (normalized)
- BA hourly solar and wind generation (normalized)
- Change in BA demand, solar, and wind generation over the preceding two hours (normalized)
- System frequency
- Hour of day
- Month
- Year
- Day of month
- Day of week
- Day type (weekday versus weekend or holiday)

Figure 28 shows the relative importance of each of the variables used by the random forest model for 27 BAs. In this context, “relative importance” reflects the role that each variable plays in the many internal decision trees that constitute the random forest—how important each variable was in aggregate for determining the predicted CPS1 value. A variable might be important because it appears in many decision trees, or because it makes a big difference when it does appear. (In other words, the two branches of a single decision tree based on a variable lead to very different outcomes.) The importance of each variable is “relative” in the sense that the sum of all the relative importance values is 100 percent. The relative importance only reflects the importance of each variable relative to all the other variables and doesn’t by itself indicate whether the model performs well or poorly.

These variables include some that are manifested for the entire interconnection, (e.g., system frequency, day of month), while others are specific to each BA, (e.g., demand, wind generation). These are not the only variables that could be studied, and a different selection of variables would produce different relative-importance results.

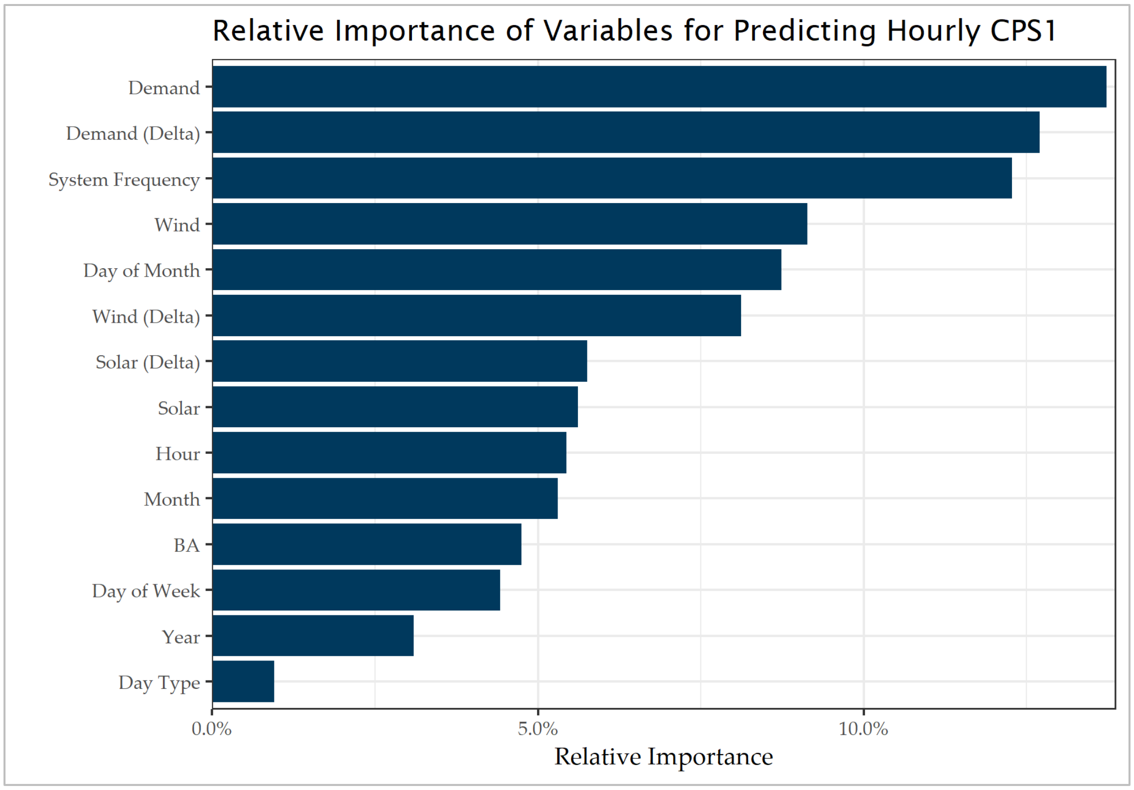


Figure 28: Importance of variables for predicting hour CPS1 scores for the dataset of 28 BAs

Unfortunately, while the model described in Figure 28 impressively captured the complexities of the training dataset, it performed badly with the testing dataset. This is known as "overfitting," and means that the model cannot be trusted to describe CPS1 data in general. It is as if the model can echo the data that was used to create it but cannot generalize to other CPS1 data. For our intended purposes, (using the model to predict things that have not happened), failure to describe things that we know *did* happen disqualifies the model. Overfitting is a common problem with random forest modeling and may be remedied by choosing variables that are less correlated. Despite ongoing efforts to find a set of variables that performs well with the testing dataset, WECC has been yet unable to produce a robust model for hourly CPS1 values. It may be that WECC has simply not tried the right combination of variables, or it may be that hourly CPS1 cannot be modeled with any combination of variables we have. The model that WECC did produce, (i.e., the model that merely echoes the training data), suggests that no single variable dominates the others.

EIM Analysis

Recent years have seen expansion of the EIM in the Western Interconnection, with accompanying operational changes.

During the five years covered by the CPS1 dataset, five BAs (Arizona Public Service, Balancing Area of Northern California, Portland General Electric, Puget Sound Energy, and Salt River Project) transitioned into the EIM. Consequently, only data from those BAs supported examination of the effect of joining the EIM. Extending the period of the CPS1 dataset would allow inclusion of additional BAs in future EIM analysis.

After adding EIM status to the variables used earlier, a new random forest model was constructed. Figure 29 shows the importance of the variables in the five-BA model.

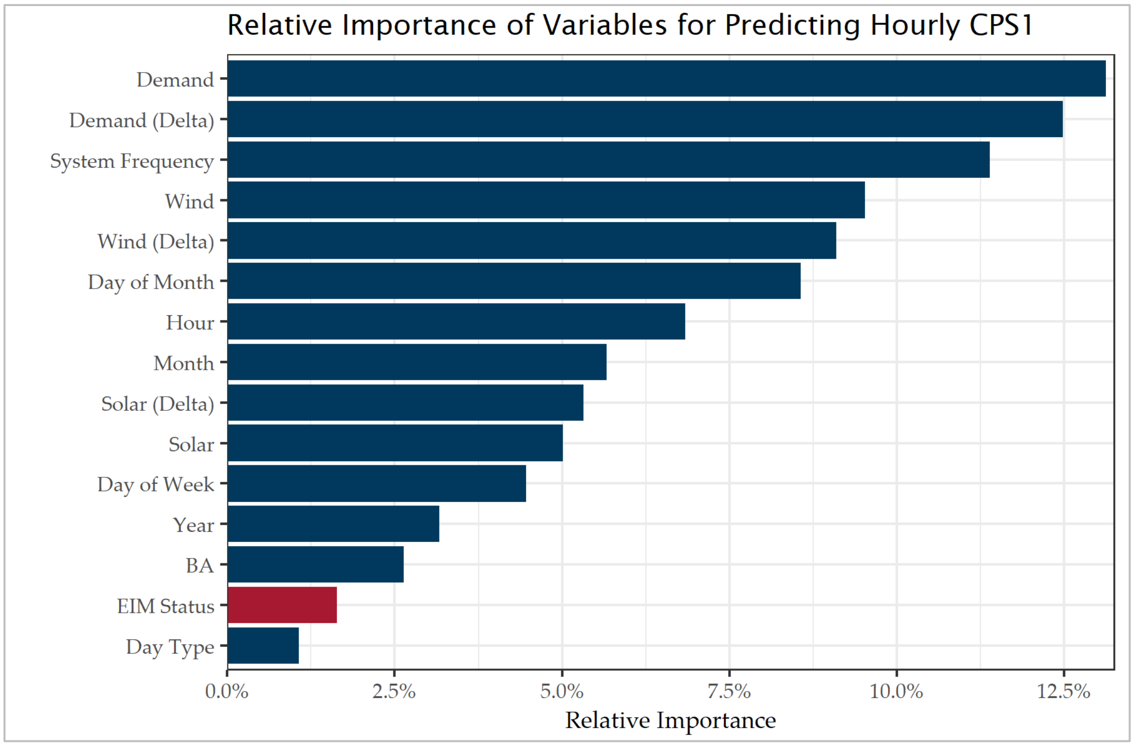


Figure 29: Relative importance of variables used to predict hourly CPS1 scores for the five BAs for which data existed.

Unfortunately, all tested versions of the EIM model also suffered the overfitting problem, which disqualifies the model for prediction purposes. As noted for the 27-BA model described above, this problem may be solvable through selection of the right set of regression variables, but the right set of variables has not yet been identified.

Findings

Despite exhaustive efforts, WECC has been unable to identify a robust model for hourly CPS1 values. Models that merely re-create the training dataset suggest that no single variable, (including renewable generation or EIM participation), has a pronounced effect on hourly CPS1 values. Consequently, this analysis has found no reason to conclude that changing generation resources and market arrangements necessitate any changes in Reliability Standards related to CPS1.

As part of this ongoing research, these results were summarized for the WECC Performance Work Group (PWG) on November 17, 2021 (the PWG has special responsibility for analyzing system control performance). While that presentation did not yield any breakthroughs, the general sentiment of the group was to encourage further investigation.

Chapter 5—Assessment of System Operations During Large Transitions of Variable Generation Output

Steep ramps present new operating conditions and risks that must be addressed by system planners and operators. This report will assess the likelihood and impacts from these ramps. Further, whether there are gaps or conflicts across various Reliability Standards or further guidance for system planners and operators to support these changing conditions.

There are two facets to the difficulties that can be encountered during these steep ramps that need to be considered.[6]

1. One facet is to ensure the BA can control the interconnection frequency and other parameters, within predefined limits while dispatching resources to offset the VER ramping either in the upward or downward direction. This is the Operating Reliability facet. Operators can be challenged to ramp those offsetting resources as quickly as the VER is ramping. Should imbalances occur, a temporary inability to balance load, generation, and interchange is solved by using operating reserves.[7]
2. The second facet to consider is to ensure the BA has sufficient resources to replace the downward ramp of the VER. This is the Resource Adequacy facet. This situation would result in a longer term inability to balance load, generation, and interchange and ensuring adequate capacity and energy reserves, as well as access through the transmission system.[8] Operationally, these situations result in a capacity/energy deficiency and potential Energy Emergency Alert (EEA) condition that includes load shedding as a mitigation.

Operating Reliabiliy	Resource Adequacy
• Goal: Maintain transmission stability, operational control, and balancing	• Goal: Maintain sufficient resources (energy and capacity) to serve demand

[6] Reliability for the bulk power system consists of two fundamental concepts:

- **Adequacy** is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

[7] Resource and Demand Balancing Control—Reliability Standards in Effect and Adequate Level of Reliability

[8] Ibid.

These two facets are very different in how they present possible reliability challenges and how mitigating measures can be put in place.

Operating Reliability

In considering the Operating Reliability facets to the ramping challenges, three technical areas are evaluated as they relate to the ability of the system operators to maintain reliability. The NERC Reliability Standards that have requirements related to maintaining balance between load, generation, and scheduled interchange are BAL-001, BAL-002, EOP-011 and TOP-002.

Resource and Demand Balancing (BAL)	Communications (COM)	Critical Infrastructure Protection (CIP)	Emergency Preparedness and Operations (EOP)	Facilities Design, Connections, and Maintenance (FAC)	Interchange Scheduling and Coordination (INT)	Interconnection Reliability Operations and Coordination (IRO)
Modeling, Data, and Analysis (MOD)	Nuclear (NUC)	Personnel Performance, Training, and Qualifications (PER)	Voltage and Reactive (VAR)	Protection and Control (PRC)	Transmission Operations (TOP)	Transmission Planning (TPL)

BAs have an obligation to maintain a balance between their generation, load and scheduled interchange. This balance is measured by Area Control Error (ACE). Large ACE causes interconnection frequency to be off nominal, creates inadvertent flow on the transmission system and causes inadvertent interchange. In general, extreme ACE is not desired by the interconnection. The steep ramps that large amounts of VER create for BAs, typically result in more system adjustments to control ACE. ACE is managed by regulating reserve. Regulating reserve is generation that can change its output in response to an Automatic Generation Control (AGC) signal. BAs maintain balance by measuring ACE and then sending AGC signals to regulating reserve resources to adjust their output. BAL-001 is the NERC Standard that specifies and requires the degree to which ACE must be managed.

BAL-001 is a performance Standard. It specifies that the measurement for ACE control is Control Performance Standard 1 (CPS1). By requiring a BAs CPS1 score to be within a specific bound, the Standard is requiring a level of performance with respect to a BAs balancing control. A BA must have adequate regulating reserve to meet the performance requirement. Therefore, by proxy, the Standard is requiring an adequate of level of regulating reserve to meet the performance requirement.

The CPS1 measurement must be within a specific limit when averaged over a rolling 12-month period. So, CPS1 is an indicator of a BAs level of controlling ACE when averaged over the preceding 12-month period. The CPS1 requirements were determined to be adequate control levels specific to each interconnection. If a BA is meeting the CPS1 requirement, they are controlling their ACE adequately. The NERC Resources Subcommittee (RS) analyzes CPS1 measurements continually. The RS analyzes not just the 12-month average of CPS1 measurements, they analyze the hourly CPS1 measurements looking for trends and issues with BA control. The RS has indicated that it is not observing any concerning trends in the CPS1 data that indicate any of the interconnections are having control difficulties.

As discussed earlier, BAL-001 has requirements for meeting CPS1 metrics. It also has requirements for adhering to BA ACE Limits (BAAL) that become more restrictive as frequency drifts farther from the nominal 60Hz. If a BA was having difficulty maintaining balance (controlling ACE) it would have BAAL exceedances. It does not appear that any modifications to this Standard are needed, with respect to steep ramps associated with high percentages of VER. The NERC RS monitors those metrics and it is not observing any concerning trends or issues with CPS1 or BAAL exceedances, and so is not recommending any changes to BAL-001.

BAL-002 deals with ACE following a contingency of a loss of a resource. Contingency reserves are generation that can be deployed following a loss of generation. Contingency reserve can consist of both spinning and non-spinning reserve. Spinning reserve is unloaded generation, connected to the system, that will automatically respond to frequency changes. Non-spinning reserve is generation—or other resources, such as load responsive--that can be brought online and will respond within a certain amount of time. Since BAL-002 specifies the disturbance recovery period to be 15 minutes, non-spinning reserve used for BAL-002 would have to be capable of responding in less than 15 minutes. Since this Reliability Standard is dealing with contingencies, it is not directly related to steep ramps associated with high percentages of VER. It is more related to maintaining contingency reserve and deploying that reserve when a contingency happens. Therefore, BAL-002 does not appear to require any modifications.

In both BAL Reliability Standards, managing steep ramps is not explicitly called out; however, the specified performance obligations essentially require studies to be performed, operational procedures to be put in place, and market rules to be adopted to ensure those performance obligations are met. While the performance obligations in the Reliability Standards demonstrate "what" is required, Reliability Guidelines help explain "how" certain requirements can be met and best practices for meeting those requirements. We recommend the existing *Reliability Guideline--Operating Reserve Management*[9] be enhanced to provide best practices around how best to manage and establish operating reserve requirements in recognition of increasing steep ramp conditions.

When steep ramps are projected to increase, establishing operating reserve requirements by studying the future system states is an essential initial step. At the core of the steep ramp issue is the goal of determining and maintaining sufficient operating reserve requirements. NERC Reliability Standards define performance requirements to maintain reliability, regardless of the resources or loads present on the system. Therefore, no matter the ramping condition—appropriate operating reserve requirements

[9] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Operating_Reserve_Management_Guideline_V2_20171213.pdf

need to be established based on expected conditions (resource and demand-side). Generally, if a performance requirement cannot be met, it implies that the entity has failed to ensure resources are available and deployed (i.e., using a variety of market, regulatory, and operational mechanisms) to meet the required performance standard. Therefore, and energy deficit in these conditions is not due to a failure of the performance measurement itself, rather it is an indication that performance has failed and not met expected values.

TOP-002-4 ensures that Transmission Operators (TOP) and BAs have plans for operating within specified limits and has some requirements that closely resemble those of EOP-011-1 R2.2.3. TOP-002-4 R4 states:

> **R4**. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses:
>
> > **4.1** Expected generation resource commitment and dispatch
> >
> > **4.2** Interchange scheduling
> >
> > **4.3** Demand patterns
> >
> > **4.4** Capacity and energy reserve requirements, including deliverability capability

R4 is an existing requirement for BAs to have a plan for the next day that would address these steep ramp periods. However, one-day ahead planning may not be adequate to develop these plans. More time is required if resources outside the BA are needed. Rather than recommending an immediate modification of TOP-002-4, we recommend that the Reliability and Security Technical Committee (RSTC) produce a Reliability Guideline in support of TOP-002-4 that makes it clear that steep ramps associated with VER need to be a part of the next-day Operating Plan and a longer time-frame for analyzing and addressing those issues may be needed. This also highlights the gray area between control issues due to steep ramps and resource adequacy issues that might be independent of steep ramp issues. We further recommend gathering industry feedback to determine whether a longer lead time needs to be memorialized within TOP-002, providing further time to ensure operating reliability and energy sufficiency.

Resource Adequacy

As presented in several NERC Long-Term Reliability Assessments, increased operator flexibility and reserves are needed to manage an evolving resource mix. The resource adequacy challenge is separate from the Operating Reliability challenge, as it is related to ensuring "sufficient" resources are constructed, operating, and available to support demand requirements. Through the Reliability Assessment process, the ERO evaluates the flexibility and energy requirements of the future, though, the ERO cannot order the construction of new capacity. Further, there are a variety of mechanisms in place to set these requirements, including integrated resource planning processes and wholesale electricity market approaches. These mechanisms need to consider the future states of the system, and in particular, provide confidence and assurance that capacity and energy will be available to support and offset steep ramps.

Based on recent events in California, and other areas experiencing steep ramps, the challenges appear largely to be a result of insufficient resource availability and energy assurance. The RSTC has created the Energy Reliability Assessment Task Force (ERATF) that has undertaken work in this area (see section below).

EOP-011 requires entities to have an Operating Plan to mitigate Capacity and Energy Emergencies within its BAA. Capacity and Energy Emergencies are defined as:

> **Capacity Emergency**—A condition in which a BAA's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
>
> **Energy Emergency**—A condition in which a Load-Serving Entity or BA has exhausted all other resource options and can no longer meet its expected Load obligations.

With sufficient available, flexible, and accessible resources, it does not appear steep ramps associated with high percentages of VER are a reliability concern. That is true if the BA has enough fast-acting generating capacity to replace the steep downward ramp of VERs. It is simply a matter of being able to ramp up replacement generation as fast as the VER is ramping down. If the ramp-up cannot equal the ramp-down, the imbalance is temporary until the replacement generation can achieve the needed output—and observations show the support from the interconnection is being adequately balanced. During extreme weather conditions, longer duration deficits could ensue.

However, if the BA does not have enough resources to replace the VER that is ramping down, the challenge is one of resource adequacy, and EOP-011 and TOP-002 describe the operational responsibilities of the BAs and TOPs.

EOP-011 requires that BAs develop, maintain and implement a plan to mitigate Capacity and Energy Emergencies. Specifically, R2.2.3 requires that BAs manage generating resources to address capability and availability. It appears that EOP-011 is adequate since it has requirements for BAs to manage generation resources with respect to capability and availability, the two main issues with VER.

MOD-031-2

Data sharing is needed to support reliability studies, assessments, and ultimately meeting the performance requirements in the NERC Reliability Standards. MOD-031-2 provides authority for applicable entities to collect demand, energy, and related data to support these reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

Energy Reliability Assessment Task Force

The ERATF is identifying solutions to support the adequacy challenges related to ensuring sufficient energy supplies. The industry task force is offering solutions with the use of guidelines and enhancements to Reliability Standards. Specifically, the group is evaluating the flexibility required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year. During 2022, the ERATF expects to submit a proposal for a new or enhanced Reliability Standard. A set of sub-teams of the ERATF were formed to review of the existing NERC Reliability Standards from the viewpoint of energy assurance to identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available as long as capacity exists. This assumption is now under review with the new resource mix and may not be true always. Energy assessments are needed in the long-term planning, operational planning, and operating time frames requiring the monitoring of the availability of resources to deliver energy.

Among other recommendations, the ERATF is urging energy assessments and criteria be established. Energy assessments should be required, including the appropriate assumptions and scenarios that account for but are not limited to:

- Time-coupled restrictions on the availability of fuel,
- The impact of energy storage and other flexible resources,
- The logistical constraints of the associated fuel delivery supply chains,
- Common mode outages not connected to fuel supply,
- Coincident outages of multiple independent resources,
- Outage duration based on failure modes, and
- The unique characteristics of variable resources.

Therefore, the resource adequacy and energy sufficiency facets of the "ramping" challenges in this report appear to be addressed by the ERATF effort.

Findings

In review of the NERC Reliability Standards and Reliability Guidelines, it appears there are already requirements within the current set of Reliability Standards to ensure the reliability operation of the BPS. This includes requirements on balancing, emergency operation and preparation, and transmission operation. Implicit in these requirements are both the operational and planning mechanisms that are designed to ensure performance requirements are met. Therefore, forecasting, planning, and preparing for steep ramp conditions are already obligations of system operators.

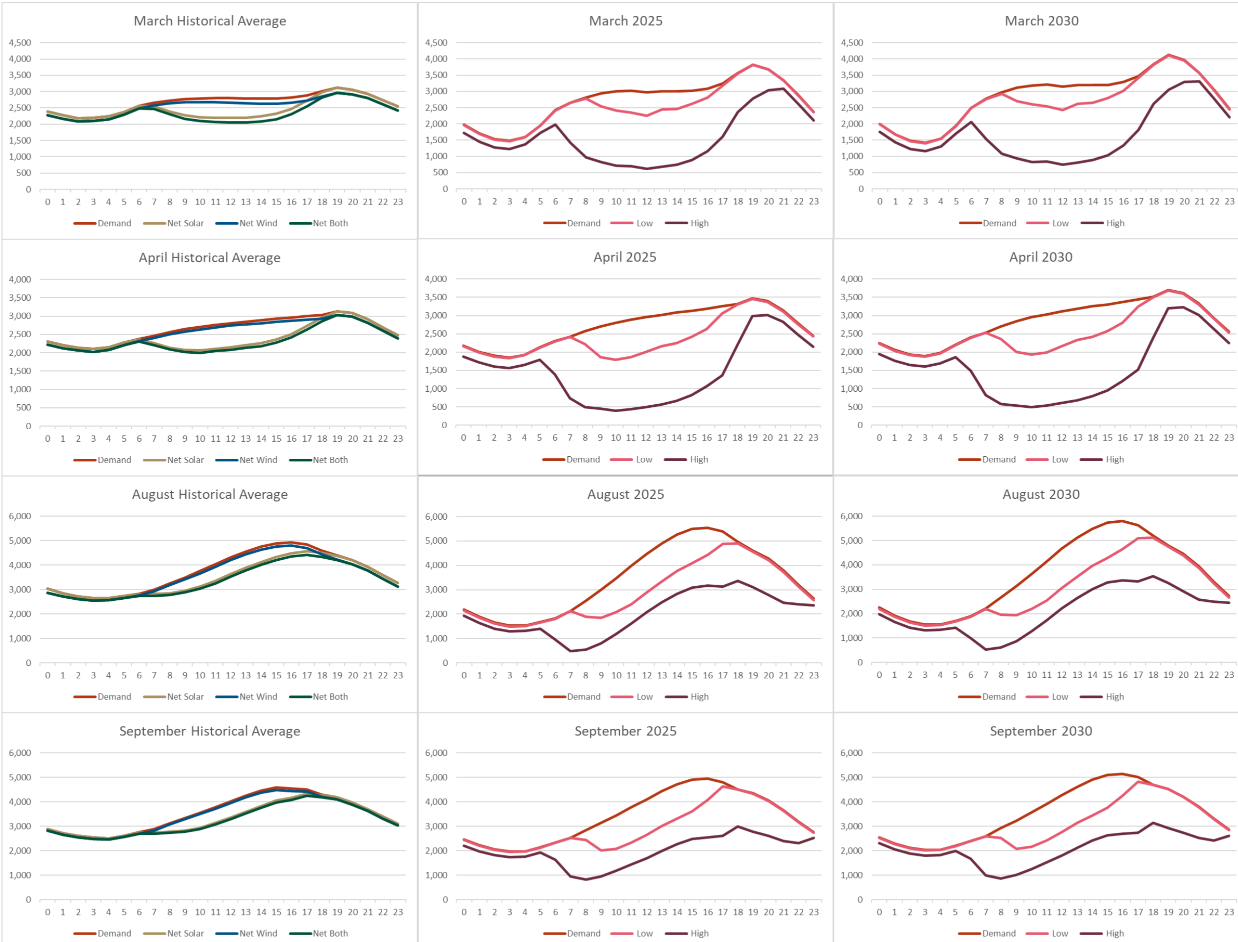
TOP-002-4 R4 requires a day-ahead Operating Plan that addresses expected generation resource commitment and dispatch, demand patterns, and reserve requirements. Entities have indicated that one day ahead provides insufficient time to plan and procure resources if faced with a capacity shortfall. Therefore, the RSTC should develop a Reliability Guideline that suggests best practices, with suggested time frames, for creating Operating Plans to ensure adequate time when planning for resource capacity in the operating time horizon.

However, the challenge of meeting demand requirements appears to arise when resources are not available or are inadequate for the conditions that the system is presented with. It follows, then, that resource adequacy and energy assurance mechanisms must recognize the studied and future system states and appropriately procure, commit, and dispatch resources.

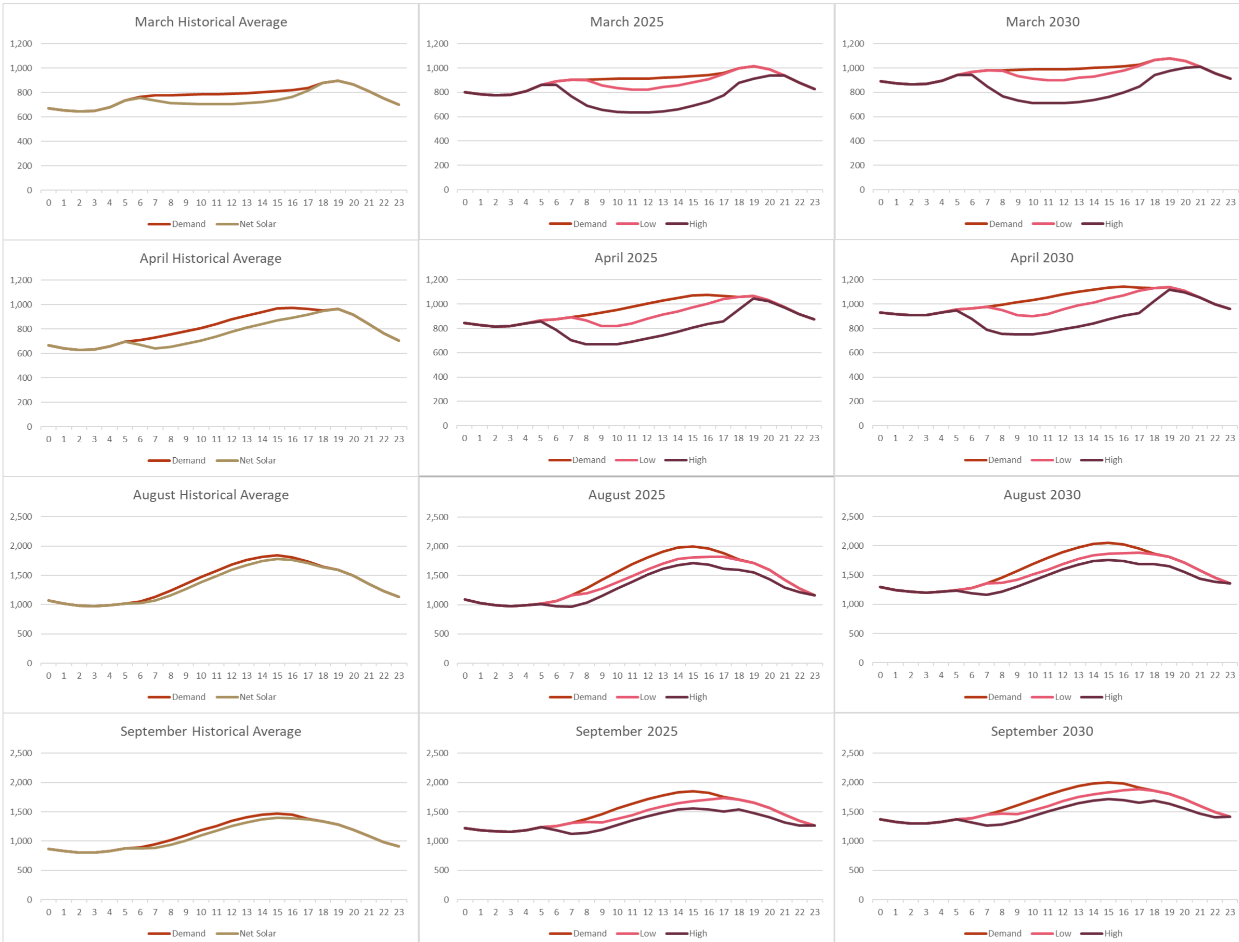
The ERATF is identifying solutions to support the resource challenges related to the availability of energy supplies. The industry task force is offering solutions in terms of guidelines and enhancements to Reliability Standards. Specifically, the group is evaluating the flexibility needed to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year. Therefore, this report will not evaluate the Reliability Standards requirements from an energy sufficiency perspective and will defer to that group's output.

Appendix A—Additional Ramping Curves

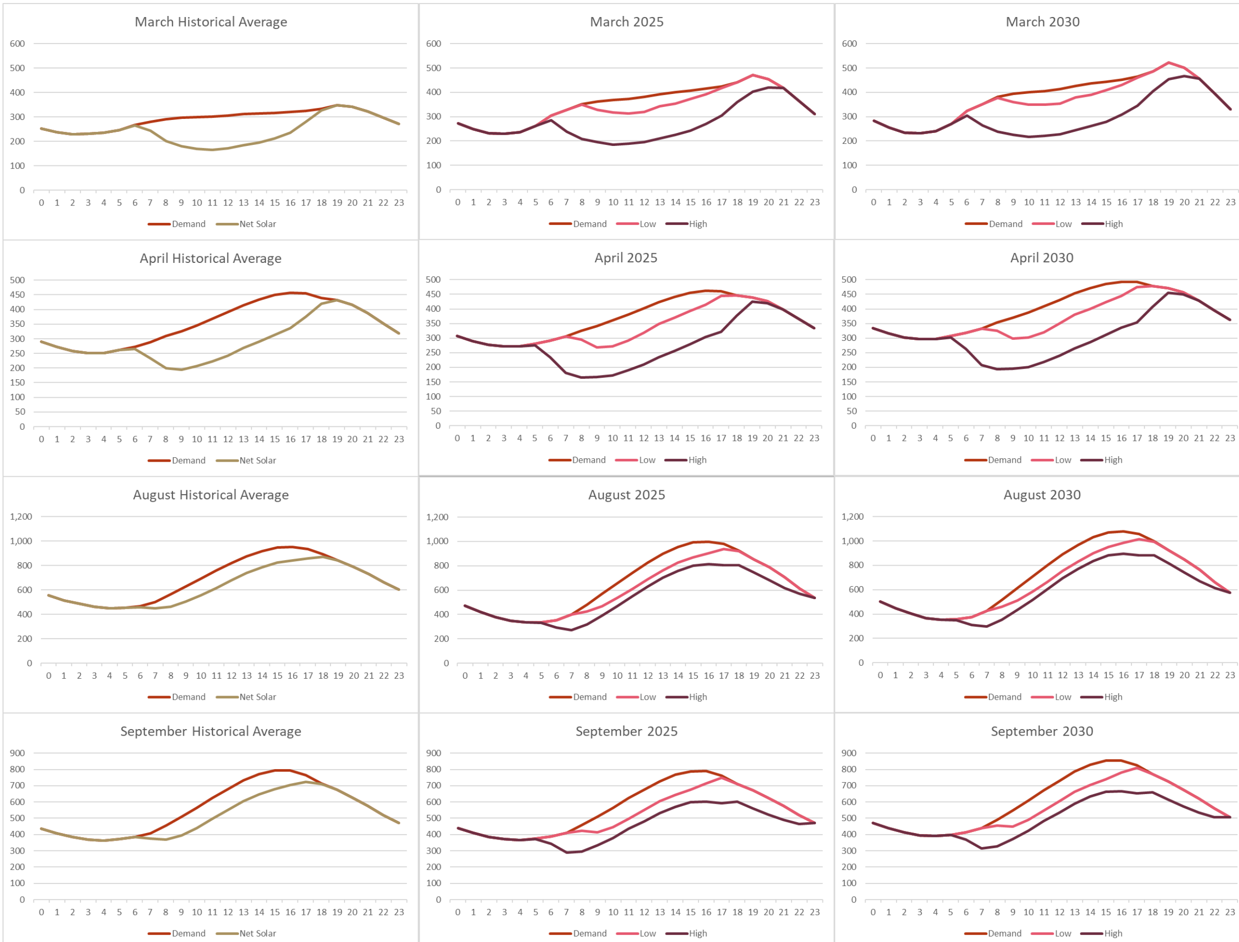
Los Angeles Department of Water and Power (LADWP)



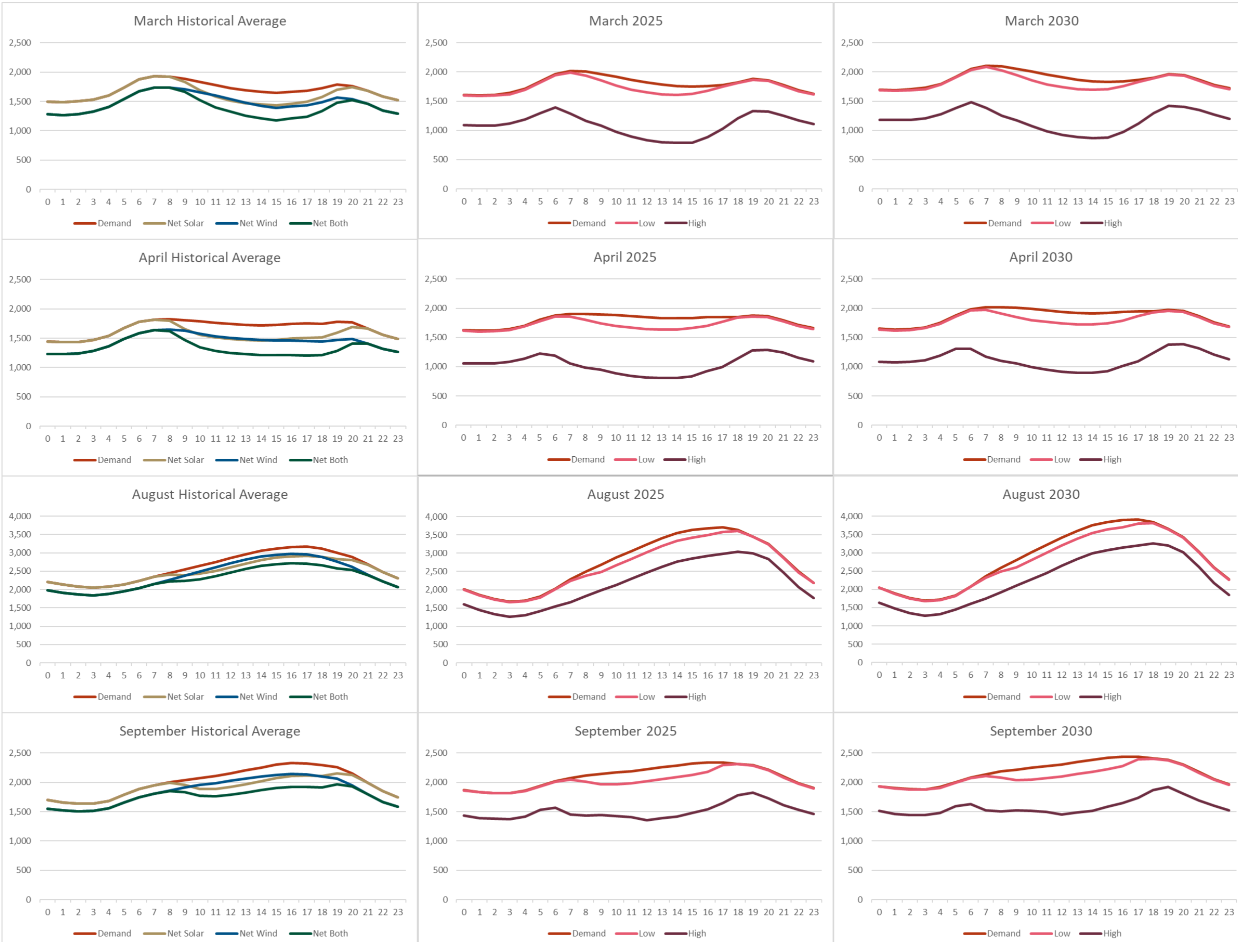
El Paso Electric (EPE)



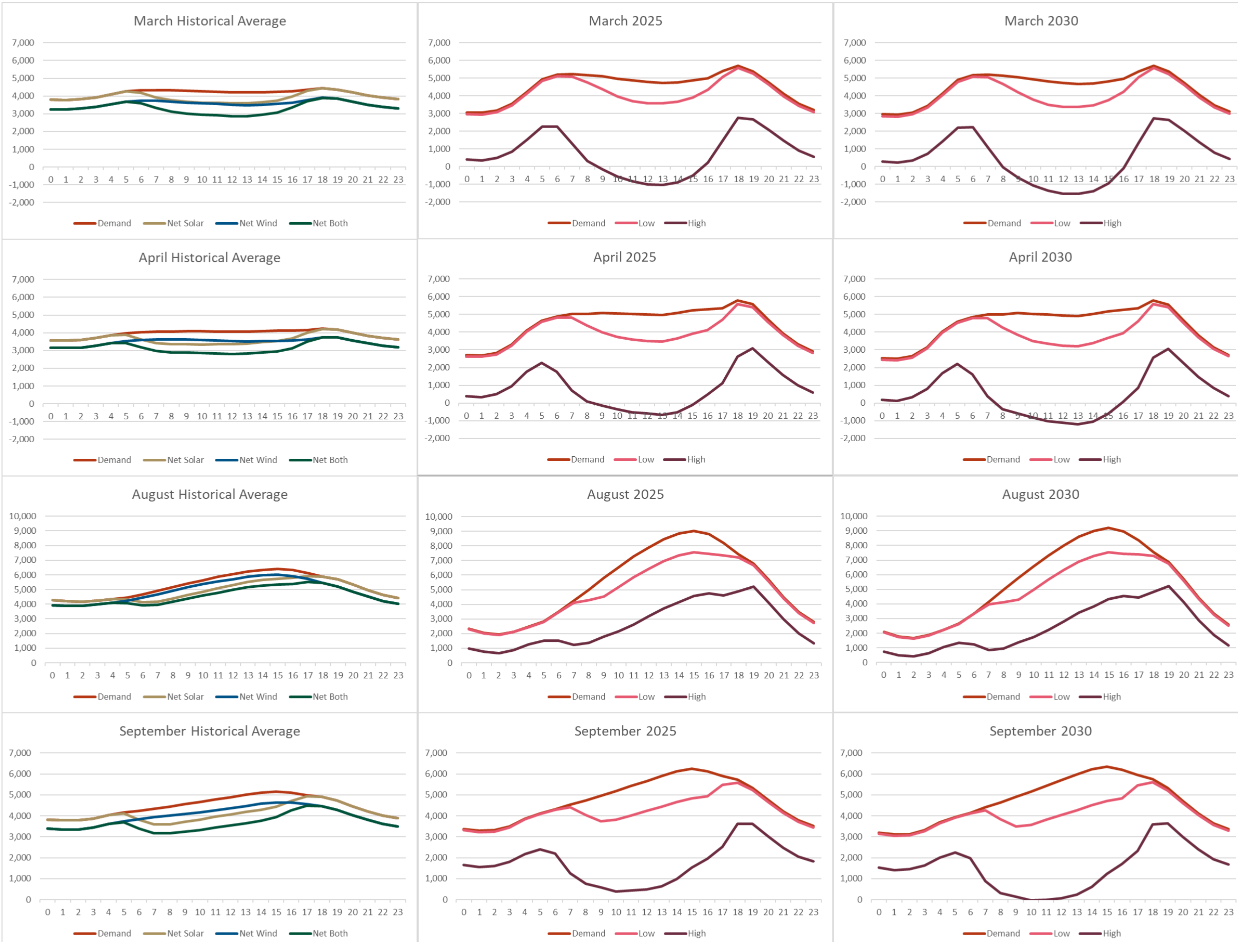
Imperial Irrigation District (IID)



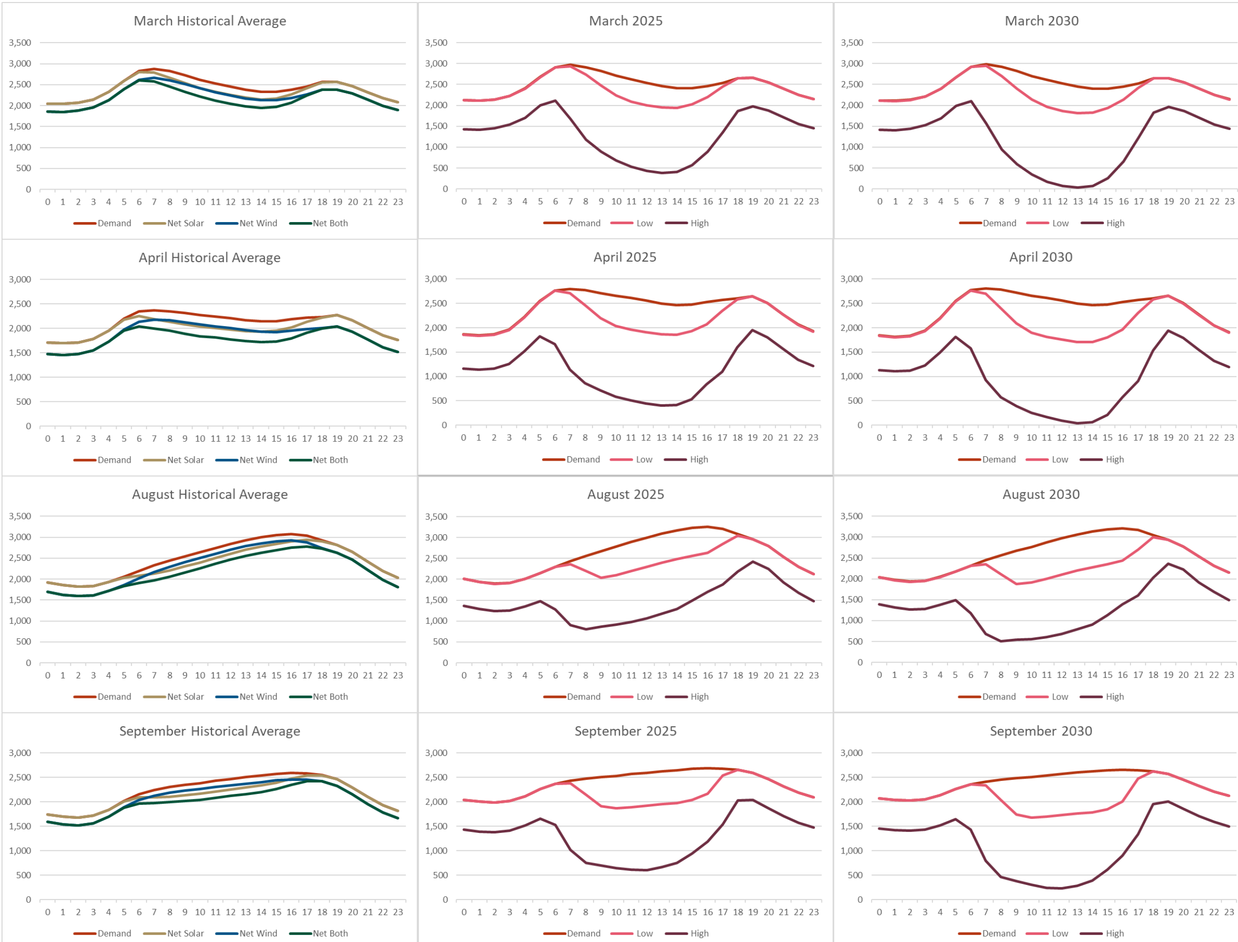
Idaho Power (IPCO)



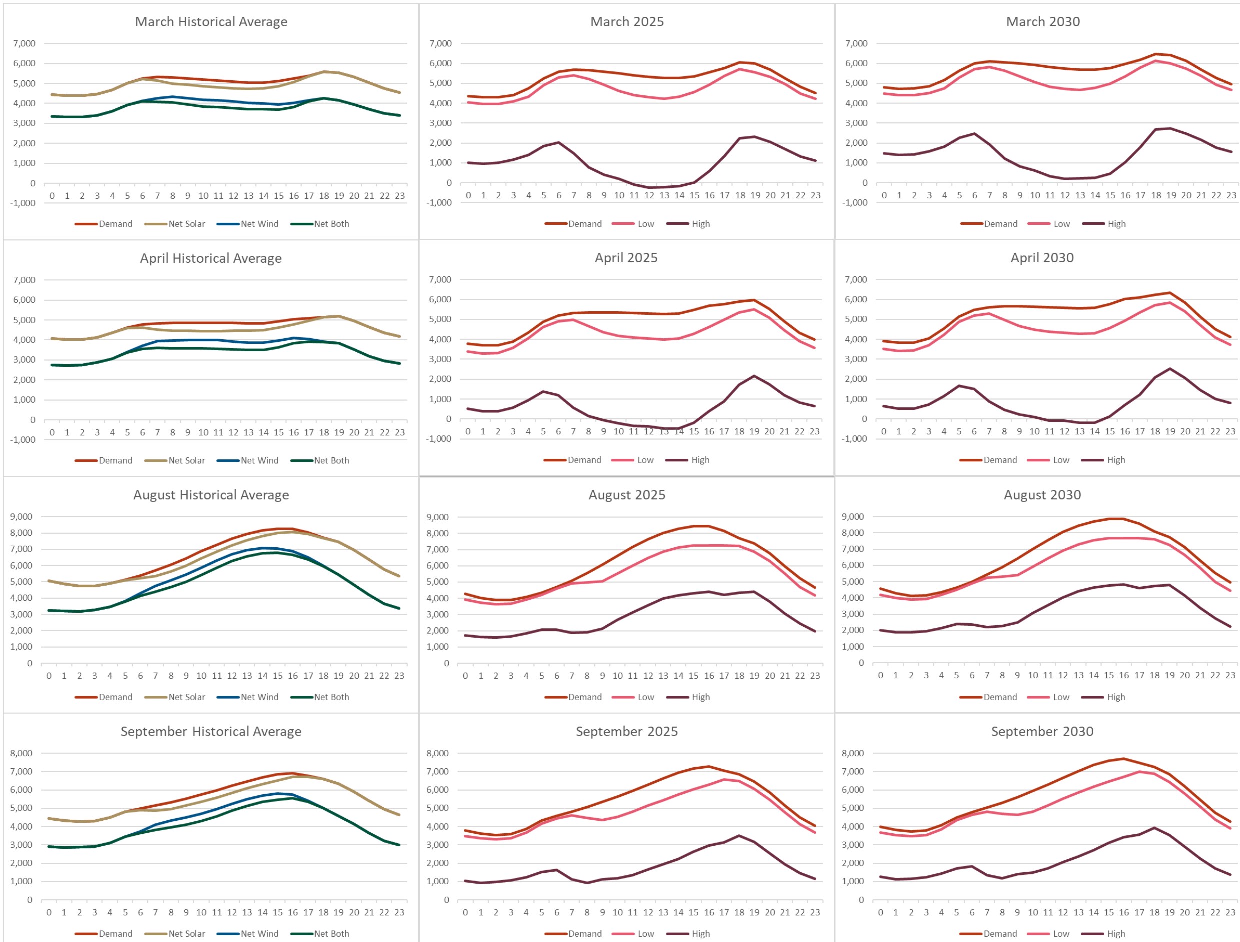
PacifiCorp East (PACE)



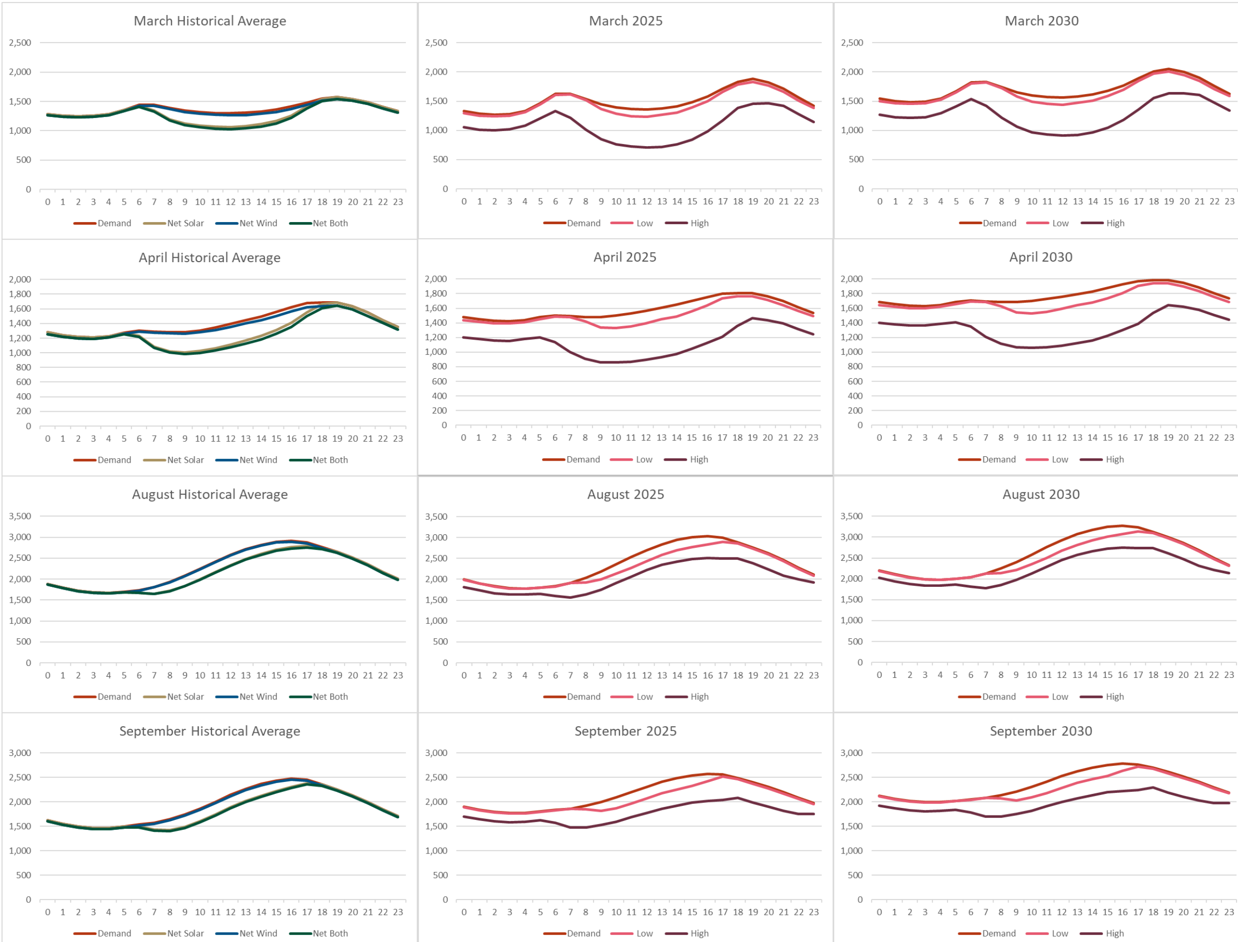
PacifiCorp West (PACW)



Public Service Company of Colorado (PSCO)



Tucson Electric Power (TEPC)



Appendix B—Generation Adjustments and Variables

WECC 2030 ADS Case

WECC and its stakeholders have been preparing a PCM to represent the entire bulk power system of the Western Interconnection on a biennial cycle since 2007. The most recent case, the WECC 2030 Anchor Dataset (2030 ADS PCM), was completed near the end of 2020. The 2030 ADS case modeled 1-in-2 load forecasts and average hydro conditions for the year 2030. The area hourly loads are in the form of a base hourly shape with a few separate load modifiers for pumping loads, behind-the-meter (BTM) rooftop solar, and demand response (DR). The BTM rooftop solar and DR serve load with positive generation, while the pumping is negative generation that increases the load. There are separate documents that describe the 2030 ADS case input assumptions.

The data that WECC collects in support of the NERC LTRA is also used to produce the WECC PCM datasets. This includes generation data (existing and future) and load forecasts from each BA.

FERC PCM Cases

WECC prepared two PCM cases to address the FERC Item #4 inquiry: a 2025 case—the VER 2025 PCM case—and a 2030 case—the VER 2030 PCM case. Both cases used the 2030 ADS case as their starting point.

Data Updates

New hourly load forecasts for the VER PCM cases were developed by WECC's Performance Analysis group using the BA monthly peak and energy forecasts and hybrid 2019-2020 actual load shapes. New generation data that was submitted in early 2021 was used to update the generating units listed in Table B-1.

Table B-1: Changes to generation that affect the 2025 VER study

Unit	MW	Fuel	Element(s)	2030 ADS	2025 FERC	2030 FERC
Cholla 1	116	Coal	Availability Retiring 12/31/2025	Missing	Re-added 116	No change 0
Cholla 3	271	Coal	Availability Retiring 12/31/2025	Missing	Re-added 271	No change 0
Craig 1	427	Coal	Availability Retiring 12/31/2025	Missing	Re-added 427	No change 0
Crescent Dunes	111	Solar	Retirement date	12/31/2050	5/1/2019 -111	5/1/2019 -111
Dave Johnston 1-4	762	Coal	Availability Retiring 12/31/2027	Off	On 762	No change 0

Unit	MW	Fuel	Element(s)	2030 ADS	2025 FERC	2030 FERC
Diablo Canyon 2	1200	Nuclear	Availability Retiring 8/26/2025	Off – circuit open	On through 8/26/2025 1200	No change 0
Fort Lupton 1,2	100	Gas	Retirement date	12/31/2020	12/31/2026 100	No change 0
Grayson CC	102	Gas	Availability Retiring 12/31/2025	Off – circuit open	On 102	No change 0
Harbor CC	208	Gas	Availability Retiring 12/31/2026	Off – circuit open	On 208	No change 0
Hayden 1	179	Coal	Retirement date	12/31/2030	12/31/2028 0	12/31/2028 -179
Hayden 2	262	Coal	Retirement date	12/31/2030	12/31/2027 0	12/31/2027 -262
Haynes 2	222	Gas	Availability Retiring 12/31/2029	Off – circuit open	On 222	No change 0
Martin Drake 6,7	208	Coal	Retirement date	12/31/2050	12/31/2022 -208	12/31/2022 -208
Martin Drake GTs	163	Gas	Temporary additions to replace units 6 and 7	Absent	Added 5/22 – 7/22 163	Added 5/22 – 7/22 163
Meikle Wind	+56	Wind	Capacity increased	124	180 56	180 56
Millennium CC	+66	CC	Capacity increased	310	376 66	376 66
Rawhide 1	280	Coal	Retirement date	12/31/2050	12/31/2029 0	12/31/2029 -280
Springerville 1	387	Coal	Retirement date	12/31/2050	12/31/2027 0	12/31/2027 -387
Springerville 1,2	793	Coal	Operation	All year	Seasonal[10]	Seasonal
Change in capacity (MW) compared to 2030 ADS:					+3374	(882)

[10] Beginning in 2023, Tucson Electric Power (TEP) plans to operate Springerville units 1 (387 MW) and 2 (406 MW) from April through September but keep only one unit running from October through March. After Unit 1 is shut down in 2027, Unit 2 would be operated seasonally until its 2032 retirement.

Behind-the-Meter Rooftop Solar

The PCM datasets for the VER studies do not explicitly model any Behind-the-Meter (BTM) rooftop solar. The team felt that this was not necessary since the BA load forecasts already accounted for this and the hourly shapes from 2019 and 2020 captured the midday slump in demand.

Although there will undoubtedly be more BTM rooftop solar installed in the next five to 10 years, the team felt that several off-setting loads (e.g., electrification, changes in net metering, on-site batteries, time-of-use pricing, electric vehicles) could easily absorb the new BTM generation. The Solar Energy Industries Association (SEIA) estimates that "by 2025, nearly 25% of all behind-the-meter solar systems will be paired with storage, compared to under 6% in 2020."

Carbon Tax

There are three provinces and states in the Western Interconnection that have enacted a carbon tax on CO_2 emissions from thermal generation: Alberta, British Columbia, and California. These additional costs are modeled in the PCM and directly increase the production cost based on the various emission rates. California also charges a carbon equivalence tax on imports of CO_2-emitting resources.

Modeling a carbon tax in only three areas of WECC is problematic because of the large amount of interchange and the remote generation. The resources that serve load in Alberta and California in these studies may be different than actual operations.

Fine-Tuning the Cases

Once the VER PCM study cases were built, they were tested to see whether the results were acceptable. The plan was to add additional generation if there was a lot of unserved loads. This is discussed in the results section. Ultimately, no additional resources were added to the cases.

VER 2025 PCM Study

The following input data assumptions pertain to the VER 2025 PCM cases:

Generation Availability

The generation changes shown in Table B-1 were incorporated into the case; they were often needed to make units available in 2025 that were unavailable in the 2030 ADS case. Figure B-1 shows the available capacity by region and the regional peak demands after the changes. The implied capacity margins range from 50% to 71%, but do not consider the various factors that limit generator output or the chance of higher demands.

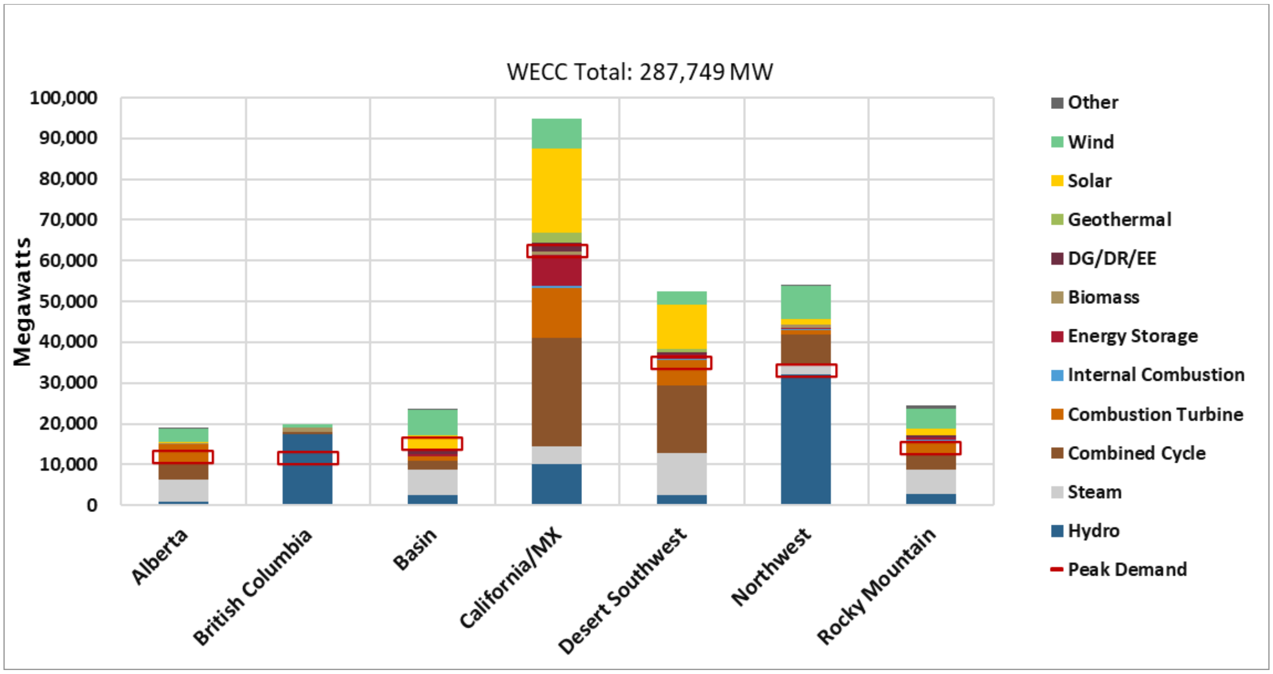


Figure B-1: Available generation capacity (MW) by region—VER 2025 case

VER 2030 PCM Study

The following input data assumptions pertain to the VER 2030 PCM cases.

Generation Availability

The applicable generation changes shown in Table B-1 were incorporated into the case.

Figure B-1 shows the available capacity by region and the regional peak demands after the changes described above. The implied capacity margins range from 34% to 63%, but do not consider the various factors that limit generator output or the chance of higher demands.

The WECC total available capacity is 2,915 MW lower than the available capacity for the VER 2025 case. That is in line with the incremental additions (9,151 MW), retirements (8,870 MW), and adjustments from Table B-1.

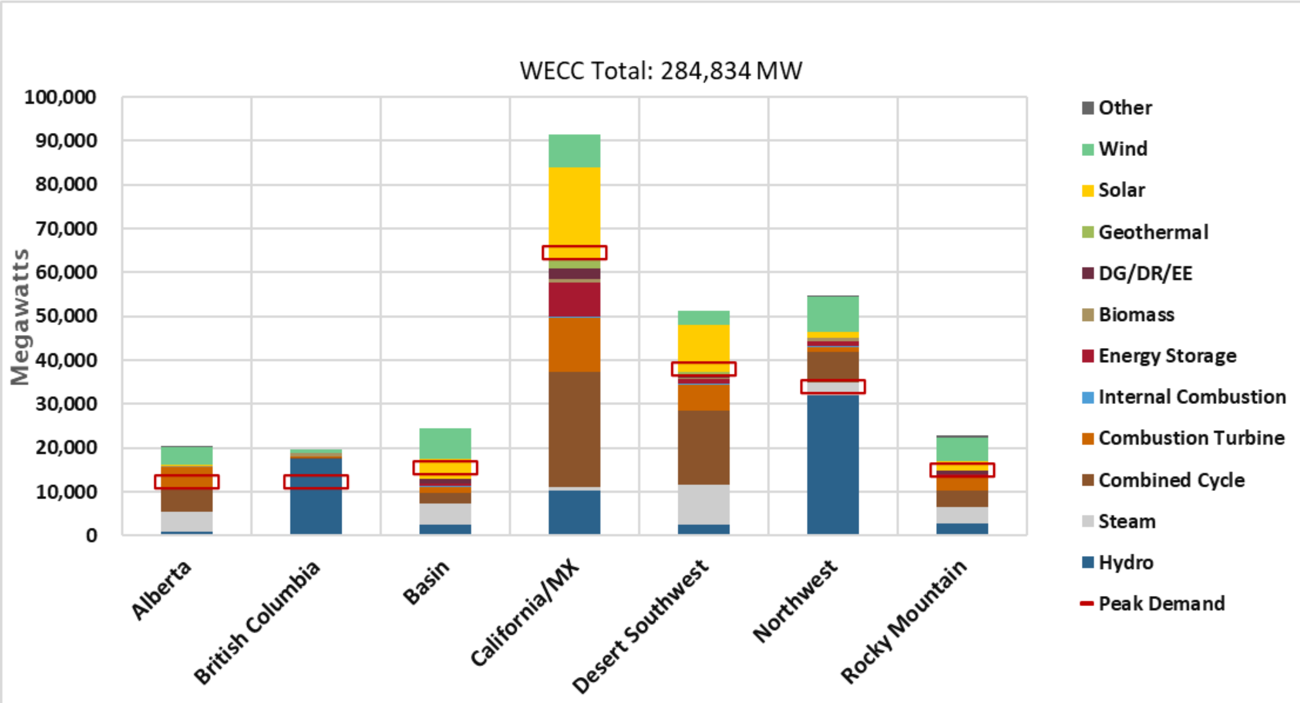


Figure B-2: Available generation capacity (MW) by region—VER 2030 case

CAISO Jointly Owned Generation and Bilateral Contracts

Generation physically located in one area is sometimes contracted for delivery to another area. This is often the case for jointly owned generation plants such as Hoover and Palo Verde. Several merchant plants also contract their output to entities other than the host BA's.

When the CAISO reports its net imports, it may include imports from the units listed in Table B-2 (and others that may not be listed). Some are dynamically scheduled, and some are not.

Table B-2: CAISO remote generation (possibly incomplete)

Unit Name	Fuel	Location
Broadview	Wind	New Mexico
Copper Mountain	Solar	Nevada
Desert Star	Natural Gas	Nevada
Dixie Valley	Geothermal	Nevada
Hoover	Hydro	Nevada
Intermountain	Coal (Gas after mid-2025)	Utah
Klondike	Wind	Oregon
Mesquite	Natural Gas	Arizona

Unit Name	Fuel	Location
Mexico Generation	Natural Gas and Wind	Baja, Mexico
Palo Verde	Nuclear	Arizona
SCE S Nevada Solar	Solar	Nevada
Western Spirit	Wind	New Mexico

The delivery of remote generation is not hard-wired in the PCM model. If the least-cost solution determines that the output should stay local or serve load somewhere else, it will. This is the same as the real system in which net schedules can change to meet the needs of the system.

Other Background Information

California Resource Mix

California has been making steady progress toward its 60% renewable portfolio goal by 2030. The California Energy Commission (CEC) tracks the progress and Figures B-3 and B-4 were extracted from their December 2019 *Tracking Progress—Renewable Energy* report. Note that WECC is hesitant to calculate the renewable generation from study cases at an area or regional level, given the intricacies of each state's renewable percentage estimates (RPS) metrics.

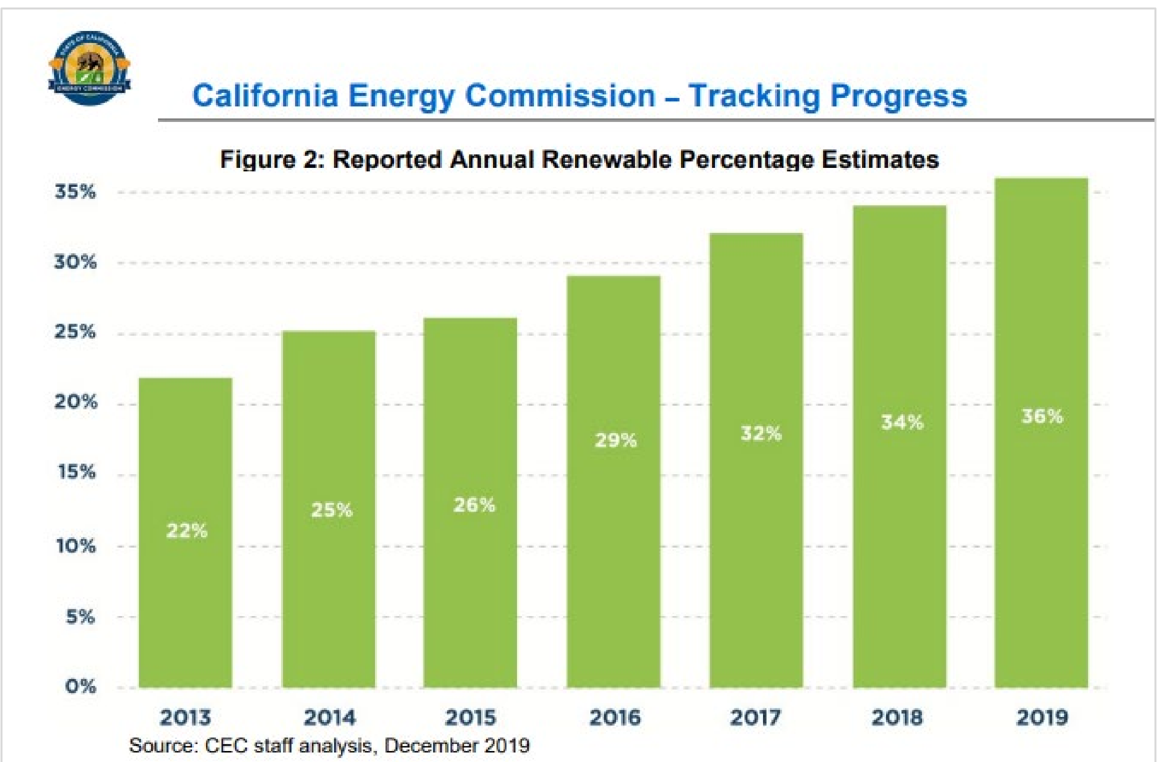


Figure B-3: California RPS progress estimates (CEC February 18, 2020)

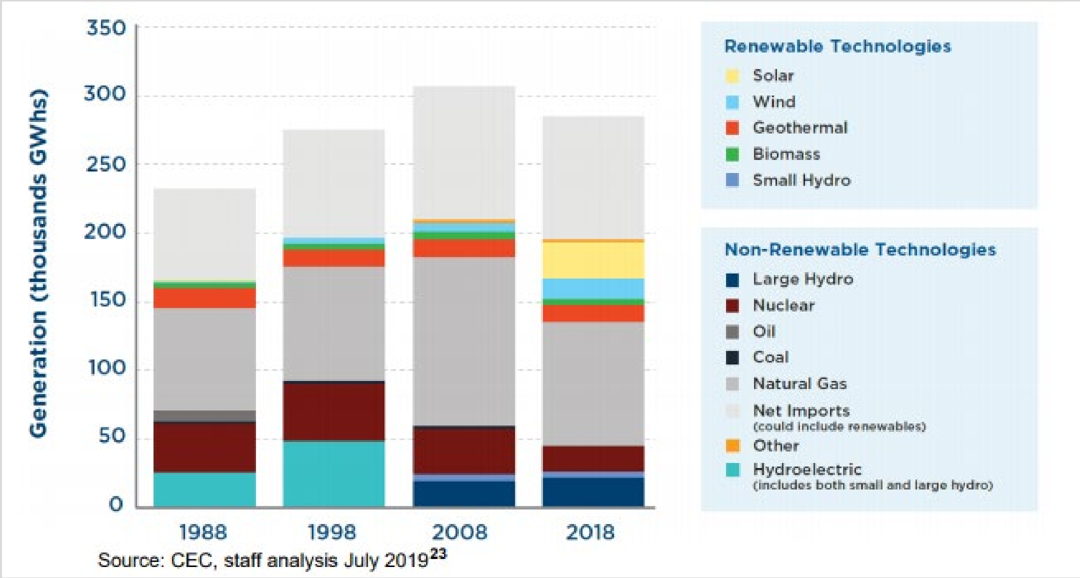


Figure B-4: California generation history (CEC July 2019)

California Net Imports

California has been a net importer of electricity from the following regions and states:

- Northwest—The Pacific AC and DC interties were built to take advantage of the large surpluses of electrical generation in the Northwest, including British Columbia.
- Southwest—Starting with Hoover Dam, California participated in several mega-scale generation projects in Arizona, Nevada, and New Mexico.
- Utah—Los Angeles and other municipal power systems in California are participants in the Intermountain Power Project and other renewable projects in Utah. A second high-voltage, direct current (HVDC) transmission line was built to import the power.

Resource Plans for the Western Interconnection (excluding Canada and Mexico)

The Energy Information Administration's (EIA) May 2021 860M Report data for electric generation includes the changes shown in Figure B-5 as year-to-year retirements and in Figure B-6 as additions for each state in the Western Interconnection. While WECC does not use the EIA data to populate its datasets, there should be a strong correlation. Note, however, that WECC removes retired units from its power flow data once the study horizon is past the firm retirement date. Hence, the latest version of the EIA 860M Report was used for these charts.

Some takeaways:

- The Arizona additions occur in the near-term, while the retirements do not occur until 2031 and 2032.
- The California retirements and additions occur from 2021 to 2025.
- The additions for Colorado are only half of what has been reported for retirements.

- EIA has not received a retirement date for Colstrip units 3 and 4 in Montana. The units were active in both VER PCM cases. The current coal contract expires at the end of 2025, although the plant operator has indicated its intention to negotiate a new contract.
- The EIA data for Utah includes a mismatch on the repowering of the Intermountain Power Project, in which the coal units will be retired, and a new combined-cycle plant built.

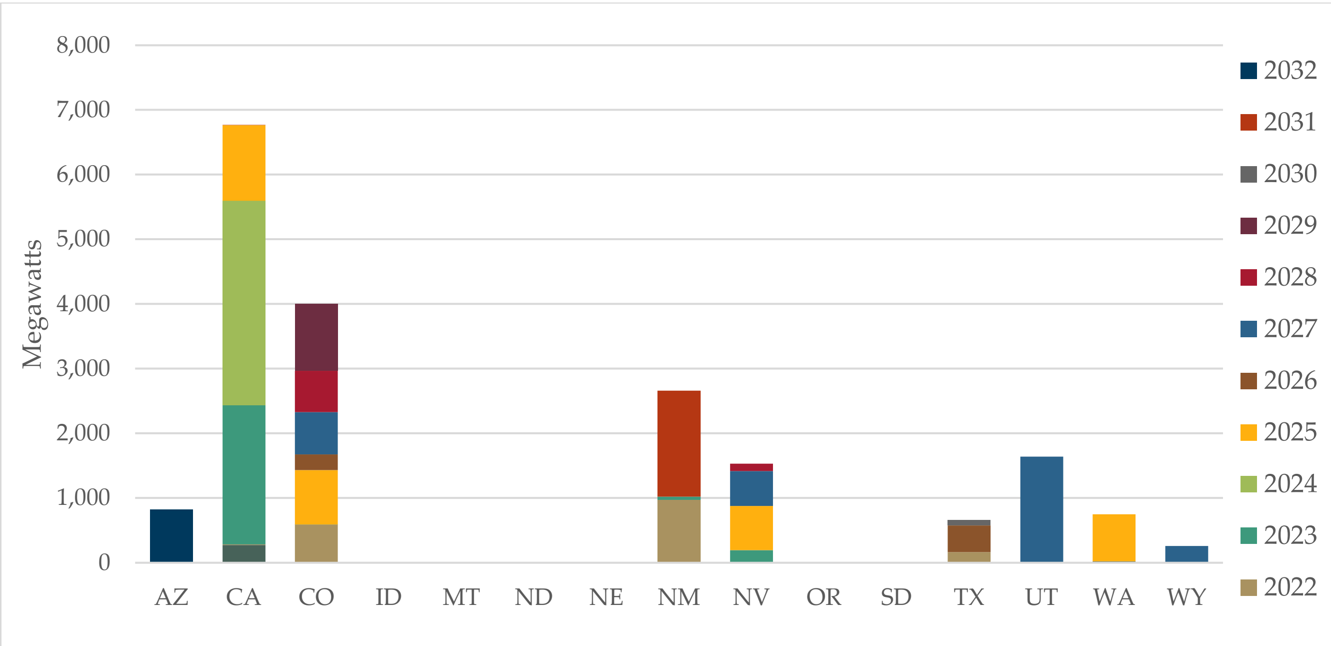


Figure B-5: EIA-reported generator retirements by state and year; as of May 2021 EIA 860M Report

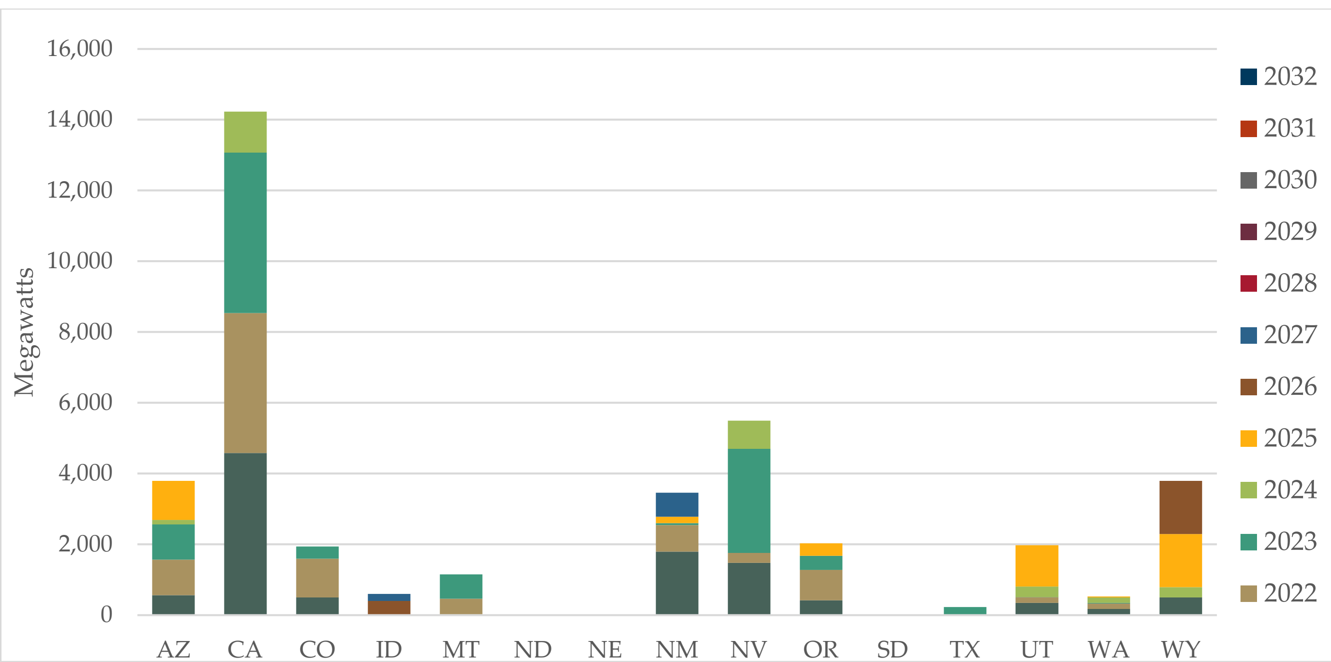


Figure B-6: EIA-reported generator additions by state and year; as of May 2021 EIA 860M Report

The projected retirements are mostly fossil fuel fired steam turbine generators. The retiring Diablo Canyon plant is California's last nuclear power plant. Several once-through-cooling generators are also being retired to meet requirements from the California State Water Resources Control Board.[11] A few noteworthy near-term examples (2019–2025) of these major types are listed below:

Table B-3: EIA sample retirements

2019/2020	Alamitos 1,2,6 (807) Boardman (642) Centralia 1 (730)	Escalante 1 (257) Cholla 4 (414) Colstrip 1,2 (716)	Inland Emp (819) Redondo B 7 (495) Navajo (2250)
2022	Comanche 1 (382) M Drake 6,7 (207) San Juan 1,4 (924)		
2023	Alamitos 3-6 (1115) Huntington B2 (218) Redondo B (821)		
2024	Diablo C1 (1159) Ormond B (1612) Scattergood 1,2 (326)		
2025	Centralia 2 (730) Comanche 2 (396) Craig 1 (446)	Diablo C2 (1164) North Valmy (567)	

As some of the large generating plants in certain areas shutdown, the transmission systems may be repurposed to deliver future renewable resources and balancing power from flexible resources. A few examples are Path 8 (Colstrip), Path 23 (Navajo), and Path 27 (Intermountain). NextEra has already announced a large, 750 MW wind project near the Colstrip power plant.[12]

Figure B-7 shows that the EIA additions for the reported period are primarily renewables and battery storage.

[11] The California State Water Resources Control Board maintains a document listing the once-through cooling requirements and latest schedule on its website.

[12] The Clearwater wind project is planned for the area in Montana north of the existing Colstrip power plant.

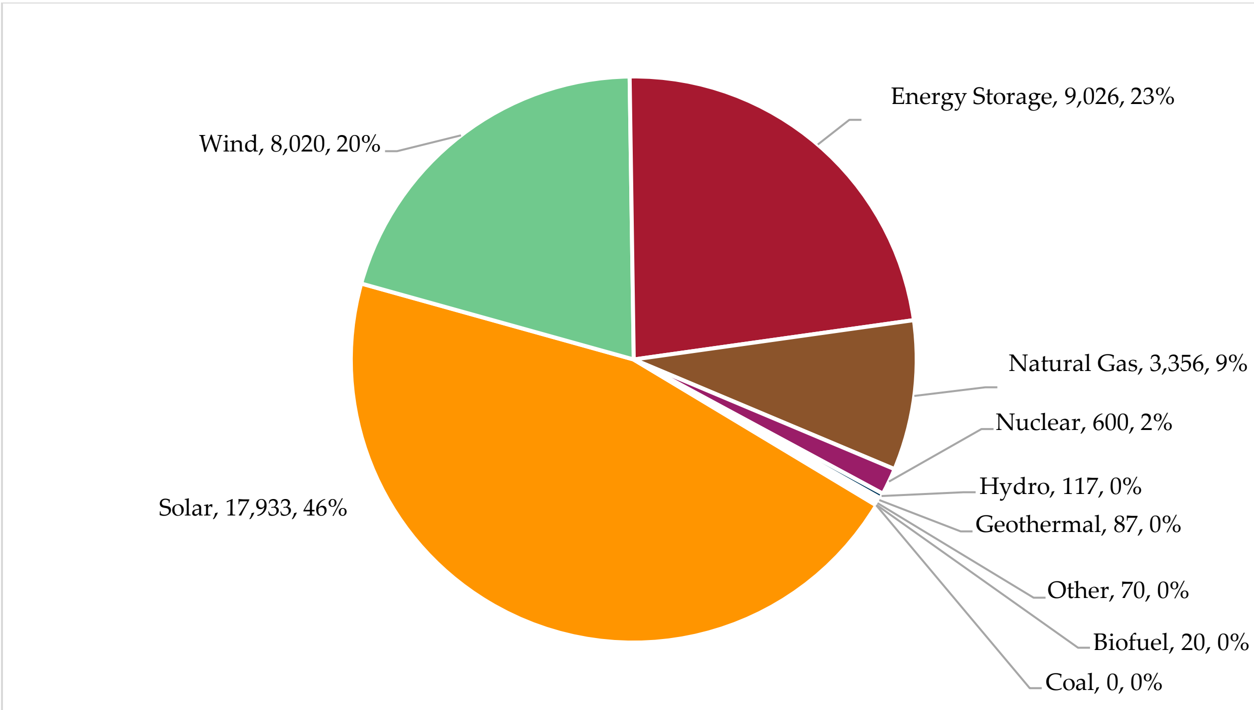


Figure B-7: Breakdown of EIA additions

One notable difference between the EIA list and the WECC PCM cases is the timing for the conversion (retirement and new build) of the Intermountain power plant. Most of the participants are showing the coal retirement in 2025 with the smaller, combined-cycle plant starting up in the same year. EIA is showing the retirement in 2027 and the in-service date of the combined-cycle plant in 2025.

Another point on the Intermountain power plant is that the PCM did not dispatch the coal plant in the FERC 2025 study due to economics. Since it is in the Los Angeles Department of Water and Power (LDWP) BA Area, the California carbon tax is applied, giving economic priority to gas-fired projects with lower CO_2 emission rates.

Appendix C—Linear Regression and the Random Forest Regression Tool

Analytic Approaches

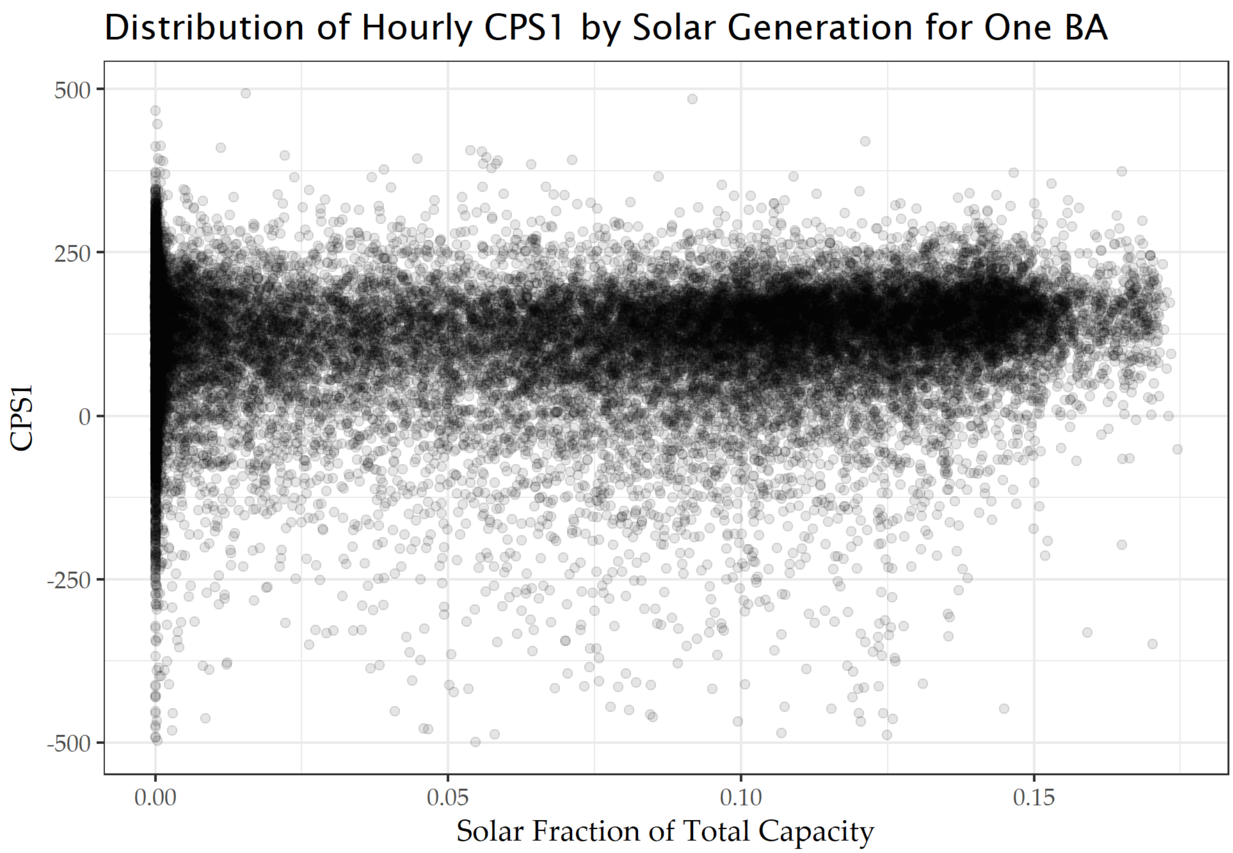


Figure C-1: Plot of hourly CPS1 by solar fraction of total generation for an example BA

Figure C-1 illustrates data on a linear modeling approach that might be used to assess the effect of solar generation on hourly CPS1 values. Although a line can be fit to the 42,000 hourly values, any effect of solar generation is miniscule relative to many other influences. Linear regression assumes that deviations from the model are symmetrically and Gaussian-distributed around the estimate, but that may not be true here. Due to the complexity of modeling hourly CPS1 values, and the infeasibility of creating an adequate model otherwise, this analysis uses random forest machine learning regression to find which parameters influence CPS1 scores and how.

The regressions take two approaches: first of the hourly CPS1 scores directly; and, second, of the variance of each combination of hour, month, and year of the hourly CPS1 scores. The rationale for two approaches is simple: while the hourly CPS1 dataset is large and complex, it is also difficult to model. Even the best model for hourly CPS1 scores was unable to explain much of the actual scores. The derived dataset based on the variance of each hour, month, and year is much smaller and predictable, but aggregates across approximately 30 days of each month. Thus, the two approaches highlight potential effects that occur on different time frames.

Regardless of the dataset or regression used, the general technique is the same: use the data to create a model, then use that model to predict counterfactual outcomes – what *would have* occurred under specified conditions. If those specified conditions are historical, then the model can help explain why CPS1 scores had actual values in the past. Otherwise, the specified conditions can describe what might happen in the future. Attribution of outcomes to specific input conditions should be done cautiously, especially when using machine learning. If, for example, small changes to model inputs lead to inconsistent changes in the predicted variable, it might be difficult to draw a simple conclusion about the relationship between the two.

The random forest model is only informed by combinations of input data found in the training dataset; so, asking the model to predict outcomes beyond the range of the training dataset is unrealistic. The approach used for this analysis is to compare the mean and variance of predicted CPS1 scores for the *actual* wind and solar generation, 75% of the actual wind and solar generation, 50% of the actual wind and solar generation, and zero wind and solar generation. Only if these results are internally consistent might we begin to draw conclusions about the predicted effect of less wind or solar generation. If these results are not internally consistent, we may be asking the model to provide information that it does not have.

Random Forest Regression

We performed a CPS assessment using the random forest regression approach, which uses internal decision trees to model complex relationships between variables. One strength of this approach is that it does not require specification even of the form of the relationships. The algorithm finds patterns by randomly searching through all variables. However, one weakness of the tool is that its internal logic is opaque to the user. In other words, the random forest model is a black box that produces predictions that prove accurate without revealing its inner logic. Another weakness of the random forest approach is that, because it is very new, standard methods for estimating prediction confidence intervals are still being developed. This means that, while producing a prediction is easy, it is not easy to say *how good* the prediction is. This contrasts with classical statistical models, for which the probability distribution of a prediction can be computed analytically. This is a topic of ongoing research.

In the worst case, there may even be a risk that a random forest model might make a prediction that cannot be supported by the data used to create the model. So, the model might produce a prediction that is very precise but represents an impossible combination of input variables. Consequently, the random forest analyses described here should be considered initial explorations or proofs-of-concept, rather than definitive.

While random forest modeling allows prediction of complex phenomena, the accuracy of those predictions is not well-characterized. The model can easily produce predictions, but we cannot easily differentiate the good predictions from the bad. Consequently, any predictions should be used conservatively. For this study, predicting the effect of increased or decreased wind or solar generation will only be assessed qualitatively.