Electric Reliability and Security for the West

August 2020 Heatwave
Event Analysis Report

March 19, 2021

Introduction

From August 14 through August 19, 2020, the western United States suffered an intense and prolonged heatwave affecting many areas across the Western Interconnection. Because of above-average temperatures, generation and transmission capacity strained to keep up with increased electricity demand. The impacts of the August heatwave struck the entirety of the Western Interconnection. This event caused the interconnection to set a peak demand record of just over 162,000 MW on August 18, 2020.

This increased demand caused several Balancing Authorities (BA) to declare energy emergencies.[1] One BA, the California Independent System Operator (CAISO), shed firm load to maintain the operating reserves needed to maintain the reliability and security of the Bulk Power System (BPS). Several other entities reported being one contingency away from needing to shed load as well.

Because of the extreme effects on the entire Western Interconnection, WECC analyzed this heatwave event using the structure of the Electric Reliability Organization's Event Analysis Process.[2] The Event Analysis Process begins with registered entities assessing an event and submitting their assessments and other requested information to WECC for evaluation and analysis. Through this process, WECC identified four categories for analyzing the interconnection's susceptibility to the heatwave event:

1. Extremely high demand;
2. Transmission system constraints;
3. Inaccurate demand and generation forecasting; and
4. Resource adequacy.

These categories were used to develop the findings and recommendations in this report.[3] These findings and recommendations were developed with the help of registered entities and are shared throughout the industry to prevent recurrence and ensure a reliable power grid.

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[1] "A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations." *Glossary of Terms Used in NERC Reliability Standards*

[2] See *Electric Reliability Organization Event Analysis Process, Version 4.0.*

[3] WECC followed the Department of Energy's *Root Cause Analysis Guidance Document.*

Extremely High Demand

The heatwave affected the entire Western Interconnection with prolonged high temperatures resulting in record demand for electricity. With temperatures between 15 and 30 degrees Fahrenheit above normal, many areas in the western U.S. broke daily heat records. Some areas in the Southwest, for example, Phoenix, Arizona, reached 115 F. Northern cities had similar spikes, with Portland, Oregon, at 102 F.[4] Because of these high temperatures, electricity demand reached a record high of just over 162,000 MW on August 18 at 4:00 p.m. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event, CAISO's load shedding, occurred at the beginning of the heatwave on August 14 and 15.

The following findings and recommendations will show in more detail the issues directly associated with the extremely high demands during the heatwave.

Findings

Finding 1—Increased demand during summer months is creating more competition for available generation.

The high, prolonged temperatures across the interconnection caused a new peak demand record of 162,017 MW on August 18. The event showed the growing need to address generation resource planning during the summer season.

BAs in the northern part[5] of the interconnection typically experience peak demand in the winter, while the rest of the interconnection experiences peak demand in the summer. The seasonal difference in peak demand has allowed excess generation in the north to supply demand in the south in the summer, with the opposite true in the winter. This trend appears to be changing. The winter demand peaks in the Western Interconnection have remained relatively flat over the past decade, while summer demand peaks have increased. Some BAs in which demand usually peaks in the winter noted that they are becoming "dual peaking systems"—their summer demand peaks and winter demand peaks are nearly the same. Figure 1 shows how summer peaks have steadily increased, while winter peaks have stayed relatively flat.

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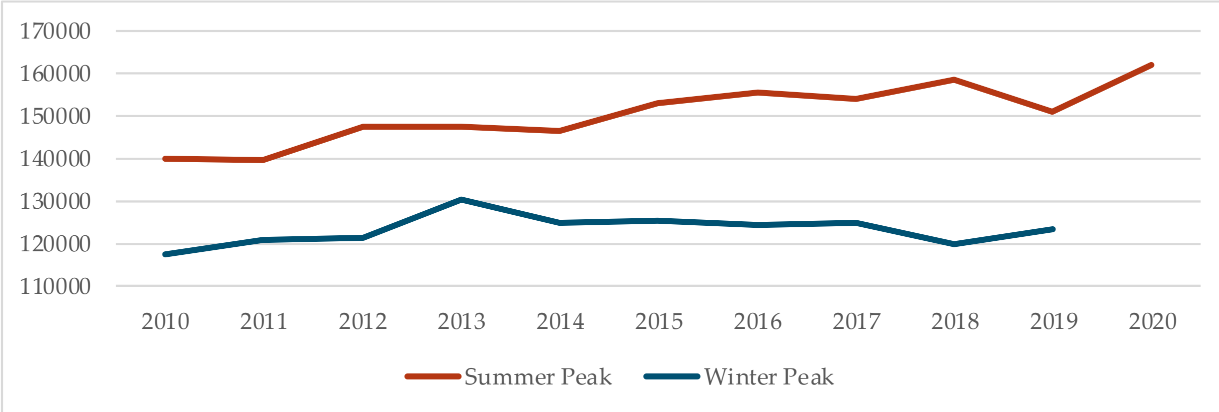
[4] See this report from ABC10 out of Sacramento, California.

[5] For the purposes of this report, the northern portions of the interconnection include Montana, Alberta, and the Pacific Northwest comprising British Columbia, Washington, Oregon, and Idaho.

Figure 1: Historical Summer and Winter Annual Peak



As demand has increased, competition for generation resources in the interconnection has increased as well, challenging BAs' abilities to meet demand.

Finding 2—Energy Emergency Alerts during the heatwave indicate generation availability challenges.

With high demands and many entities under-forecasting their day-ahead peak load and temperature, BAs struggled to find enough generation during the heatwave. As a result, BAs declared Energy Emergency Alerts (EEA) to request assistance. An EEA is a condition in which a BA has exhausted all other resources and cannot meet its demand obligations. The three levels of EEA show the degree to which a BA is experiencing generation shortfalls.[6] In total, six BAs declared an EEA-3 (also known as an EEA level 3), the most severe form of energy emergency, which signals that a BA is ready to shed, or in the process of shedding, firm load. One entity, CAISO, ultimately shed load due to a lack of available generation.

[6] EEA levels are described in Attachment 1 of NERC Reliability Standard EOP-011-1

Figure 2: Increase in EEA Events by Year for the Western Interconnection

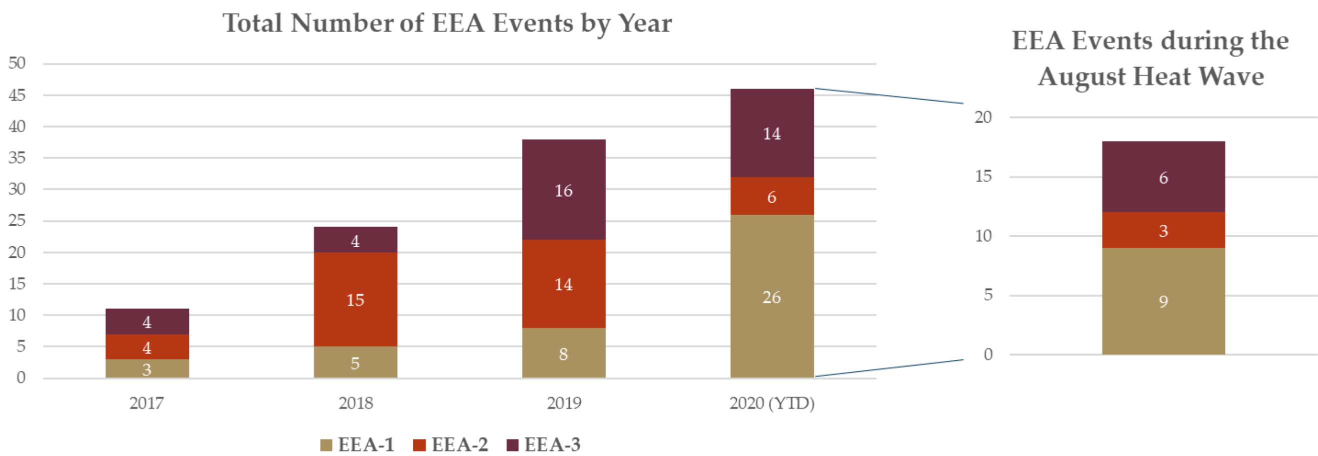


Figure 2 shows an increasing trend in the number of EEA events in the Western Interconnection over the last four years. This trend likely indicates a problem of reduced generation availability throughout the interconnection. Note that there were 18 EEA events during the heatwave alone.

Finding 3—Reliability Standard BAL-002-WECC-2a may not be applied by BAs in the same way, which can lead to different outcomes.

The continent-wide NERC Reliability Standards require BAs to maintain enough resources to meet demand; they also require BAs to maintain additional resources to respond to abnormal conditions like the loss of a large generator. In the Western Interconnection, BAs are also subject to the regional Reliability Standard BAL-002-WECC-2a. Its purpose is to specify the quantity and types of Contingency Reserves required by a BA to ensure reliable operations in normal and abnormal conditions. However, some BAs may have differing applications of requirements R1 and R2 within the standard.

Requirement R1 of BAL-002-WECC-2a states:

> *R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve…*

Subrequirement R1.1 describes the minimum quantity of Contingency Reserves BAs are required to maintain, while subrequirement R1.2 describes the types of reserves a BA can use to maintain its Contingency Reserves.

Conversations with some BAs revealed that there are differing applications of requirement R1, specifically the phrase "following an event requiring activation of Contingency Reserve." Some BAs are unclear as to whether BAs can use Contingency Reserves to address non-contingency related shortfalls when in an EEA state. This lack of clarity can result in differing actions by operators.

Requirement R2 of BAL-002-WECC-2a requires that 50% of the minimum quantity of Contingency Reserves defined in R1.1 must be spinning generation. However, since May 1 of 2017, the Western Interconnection has been in a field trial to determine the necessity of the 50% spinning reserve requirement, resulting in entities not being required to maintain 50% spinning reserve. Although requirement R2 was not in effect at the time of the heatwave event, one BA stated that it was still maintaining the 50% spinning reserve requirement specified in requirement R2. Continued adherence to the 50% spinning reserve requirement could prevent BAs from using alternative approaches to meeting the Contingency Reserve requirement while in an EEA state.

In response to these findings, WECC and the registered entities will reach out to industry to educate them on the application of Contingency Reserves as required by BAL-002-3 and BAL-002-WECC-2a.

Recommendations

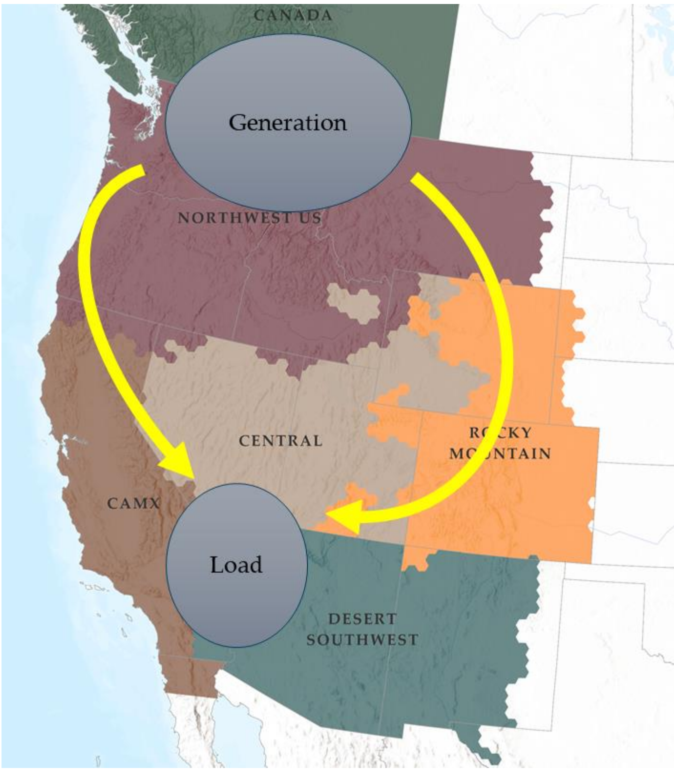
Recommendation 1—Industry subject matter experts (SME) should create a guideline to document best practices while in an EEA state.

Discussions with several BAs showed there would be value in creating a guideline that includes best practices and provides guidance to BAs for addressing reserves while in an EEA state. The guideline should include corrective actions BAs and Reliability Coordinators (RC) can consider in real-time operations and should also address future changes that can affect these actions like generation resource changes. WECC and NERC should work together with industry SMEs through technical committees to develop this guideline.

Transmission System Constraints

The Western Interconnection is characterized by an abundance of generation in the north and large load centers in the south. The transmission system that interconnects these generation and load centers contains transmission facilities along the western and eastern sides of the interconnection with few facilities in the middle, creating a transmission system loop (Figure 3). Energy can flow clockwise or counterclockwise around the transmission loop depending on its source, system topology, and system impedances. During the August heatwave, generation from the north flowed south to feed demand, travelling through the west and east sides of the transmission loop.

Figure 3: Transmission System with Energy Transfers on the West and East Sides of the System



As demand increased in the south, energy flow on the west side of the loop increased, creating congestion. Due, in part, to limited transfer capability caused by planned transmission outages, these limitations affected the amount of energy that could be transferred from the generators in the north to the load centers in the south. Planned outages and unscheduled flow exacerbated the congestion on transmission lines that occurred during the heatwave event.

Findings

Finding 1—Planned transmission outages limited north-to-south energy transfers.

Earlier in 2020, another extreme weather event damaged transmission facilities in the northwest part of the interconnection, resulting in long-term facility outages, which reduced the transfer capability through the Northwest AC Intertie (NWACI) by as much as 1,250 MW. While the NWACI constraints were the most limiting, other constraints were present elsewhere in the northwest during the heatwave. Other planned maintenance outages reduced the transfer capability of the intertie linking Canadian and U.S. power systems by up to 750 MW, further limiting the ability to transfer energy from the north to the load centers in the south.

To address these limitations, a Transmission Operator (TOP) in the northwest performed real-time studies to determine whether north-to-south transfer capability could be increased to provide more energy to the south. Upon verification, the transfer capability was increased. However, with the increased flows the TOP saw excessive phase angle differences across its system, which could have led to wide-area instability and separation of the interconnection. The transfer capability across the path was reduced again, mitigating risks of instability, but limiting the flow of north-to-south energy.

Finding 2—Unscheduled flow contributed to transmission line congestion.

Power naturally flows over the "path of least resistance" to get from the point of generation to the point of consumption. However, power transfers are scheduled along paths based on commercial methods that do not directly reflect the physics of the power system. Therefore, there is often a difference between scheduled power flow and actual power flow. Energy that flows along paths other than those specified in the schedule is called "unscheduled flow."

If an entity schedules generation from the northern part of the interconnection to supply demand in the south, it will schedule the energy either across the eastern part or the western part of the transmission loop based on the Available Transfer Capability and other commercial considerations. However, because the system impedance is typically higher across the eastern part of the transmission loop, more energy will usually flow across the western part of the transmission loop to the demand centers in the south, regardless of the paths designated in the schedules. Because of limitations across the NWACI, additional schedules were created to flow across the eastern part of the transmission loop to serve load in the south. However, the actual flow of energy occurred across the NWACI as unscheduled flow. The unscheduled flow across the NWACI exacerbated transmission congestion reducing the amount of energy available to supply peaking demand in the south.

Finding 3—Phase shifting transformers (PST) were not used to mitigate unscheduled flow.

The Western Interconnection uses PSTs to manage unscheduled flow. PSTs alter real power flow by increasing or decreasing the phase angles of the PSTs. When PST adjustments are coordinated, flows around the transmission loop can be redirected. For example, if too much energy is flowing north-to-south along the west side of the transmission loop, coordinated phase shifting actions can redirect that flow to the east side of the transmission loop.

The Western Interconnection can coordinate use of PSTs to manage unscheduled flow using the Unscheduled Flow Mitigation Plan (UFMP). According to this plan, coordinated PST mitigation action can occur when the unscheduled flow is causing congestion on Qualified Paths. At the time of the heatwave, there were four Qualified Paths in the Western Interconnection. PSTs were not used to manage congestion on the NWACI caused by unscheduled flow during the heatwave event because the NWACI was not a Qualified Path included in the UFMP.

Because PSTs were not used, the unscheduled flow exacerbated the existing congestion on the NWACI, reducing the amount of energy that could be transferred from the north to the load centers in the south.

Recommendations

Recommendation 1—RCs and TOPs should use phase shifters to mitigate unscheduled flow beyond the Qualified Paths.

RCs and TOPs should work with qualified owners and operators (QOO) and the Unscheduled Flow Committee (UFC) to find other ways to use PSTs more broadly to help relieve congestion and mitigate emergency conditions. At a minimum, these entities should consider developing a process for using phase shifters to help mitigate congestion beyond the Qualified Paths during emergency conditions. This can be done by modifying the UFMP or creating separate RC or TOP procedures outside the UFMP, but other options should also be considered.

Recommendation 2—TOPs should collaboratively investigate phase angle limitations with RCs to establish appropriate System Operating Limits (SOL) or Interconnection Reliability Operating Limits (IROL) and related Operating Plans for use in real-time operations.

During the heatwave event, a TOP in the northwest identified transfer limitations due to phase angle differences across transmission elements and monitored the phase angles in real time to maintain system reliability. However, the phase angle limitations may not have been identified in advance and were not communicated effectively to other affected entities for awareness and coordination. It is recommended that TOPs and RCs perform coordinated studies to identify any phase angle limitations within their systems under similar high stress conditions and establish SOLs or IROLs as appropriate to ensure reliability. These SOLs and IROLs should be incorporated into coordinated TOP and RC Operating Plans and shared among affected entities to prevent and mitigate exceedance of these SOLs or IROLs.

Recommendation 3—RCs, BAs, and TOPs should prepare for summer of 2021 by developing Operating Plans for similar events.

Given the trend of increased extreme weather events, it is possible that events like the August 2020 heatwave will occur again. RCs, BAs, and TOPs should prepare in advance for a recurrence of such an event by developing coordinated Operating Plans for extreme weather events and related emergencies. These extreme weather plans should be developed as soon as possible to enable entities to train operators and staff on the new procedures.

Inaccurate Demand and Generation Forecasting

Many entities' demand and generation availability forecasting proved inaccurate during the heatwave event. Issues like inaccurate day-ahead demand forecasting may mask potential reliability problems, and responding to resource shortfalls in real time does not give entities enough time to enact mitigation measures like using generators that require longer start-up times or restoring generation and transmission facilities that may be out of service for maintenance.

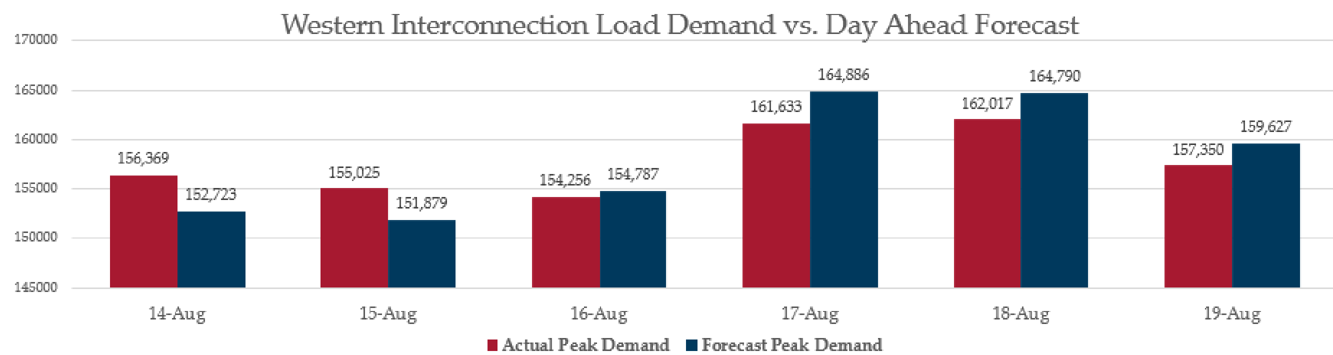
Findings

Finding 1—Inaccurate day-ahead demand forecasts contributed to reduced generation availability.

Based on information collected during the heatwave event, entities' day-ahead demand forecasting was significantly lower than actual demand for the first two days of the heatwave event, which caused an increase in real-time requests for available generation.

Based on Figure 4 below, which provides an interconnection-wide view of day-ahead peak demand forecasts compared to actual peak demand, on the days when firm load was shed (August 14 and 15), day-ahead peak demand forecasts were significantly less than the actual peak demand. Note that on the days following the firm load shed, actual peak demand was lower than forecast peak demand, and, although on most days the actual peak demand was higher than that on August 14 and 15, no firm load shedding occurred.

Figure 4: Load Demand vs. Day-Ahead Forecast



One explanation for the forecasting error is the inaccuracy of available weather forecast information, likely due to impacts related to the COVID-19 pandemic.[7] When developing day-ahead Operating Plans for August 14, some BAs did have accurate forecasts. However, others had discrepancies of two to four degrees lower than actual and others had discrepancies as high as nine degrees lower than actual. This inaccuracy can be significant, as one BA noted that a one-degree error can mean a variance in its forecast demand of 120 to 200 MW. With several BAs under-forecasting their day-ahead demand, it became difficult to procure extra generation in real time.

In addition to under-forecasting demand during the first two days of the heatwave, some BAs stated that actual power produced from variable energy resources was much lower than day-ahead generation forecasts. This over-forecasting of expected generation from variable energy resources contributed to these BAs not meeting their obligations to supply needed generation and, as a result, many were placed in an EEA.

Recommendation 1—BAs should ensure that studies have accurate forecasts and can account for demand and generation variability.

BAs should evaluate whether their demand and generation forecasting practices and tools for day-ahead and longer-term studies rely on the most appropriate data and account for weather, demand, and generation variability. To this end, BAs should examine historical and hypothetical scenarios including extreme weather events. Although events like the heatwave were once considered rare, the impacts of these types of events coupled with high system variability can have a significant impact on the overall reliability of the BPS.

[7] See report from CNN Weather

Resource Adequacy

Resource adequacy was identified as one of the top reliability risks at WECC's Reliability Workshop held in February of 2020. WECC subsequently adopted resource adequacy as one of its four Reliability Risk Priorities for 2020 and beyond. Over the last few years, resource adequacy assessments performed by planning entities, consultants, NERC committees, and others have shown potential resource shortfalls in the West, particularly in southern California. The August 2020 Heatwave Event exemplifies the resource adequacy concerns identified in those assessments and serves as an impetus for the West to address its resource adequacy challenges more aggressively.

In December of 2020, WECC released its *Western Assessment of Resource Adequacy*.[8] The findings and recommendations provided here are consistent with those in WECC's report. Refer to this report for more information on resource adequacy concerns in the Western Interconnection.

Findings

Finding 1—Variable generation contributed to the inability to meet peak demand.

The resource mix in the Western Interconnection is changing as more coal-fired base load thermal generating units are retiring and being replaced by variable generation like wind and solar. Figure 5 compares the change in resources between 2013 and 2019. In this six-year period, solar generation increased by about 37 GWh, and wind resources increased by 11 GWh. Baseload resources, however, decreased by 114 GWh. While more demand is being met by variable resources, these resources may not be generating when energy is most needed.

Figure 5: Net Generation by Fuel Type

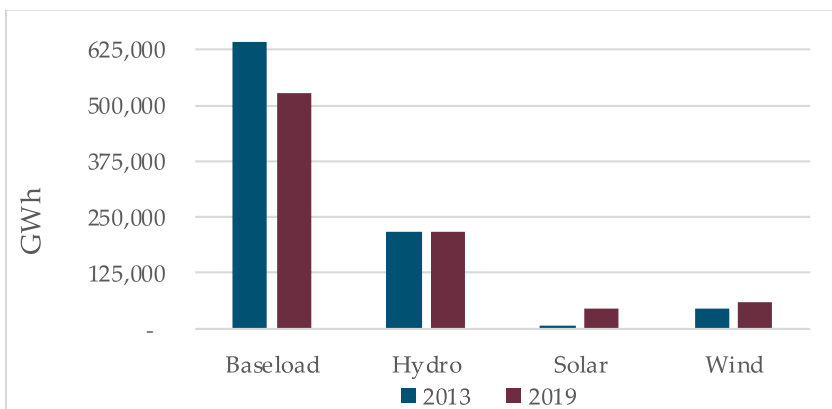
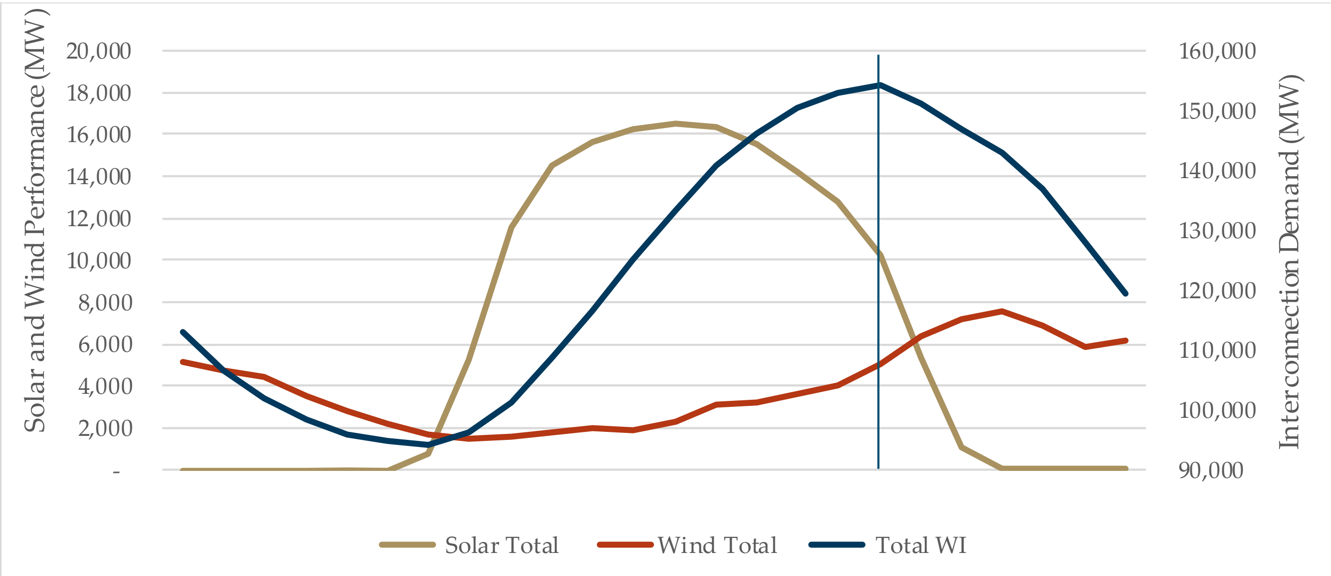


Figure 6 shows how this increase in variable generation affects the interconnection. The figure shows actual results for Sunday, August 16. The blue line represents the total interconnection-wide demand (scale on right), the gold line represents the solar generation, and the red line represents the wind generation in the interconnection (scale on left). The vertical line represents the peak demand for the day. On the peak hour solar production in the interconnection was decreasing and wind resources had

[8] See the *Western Assessment of Resource Adequacy*

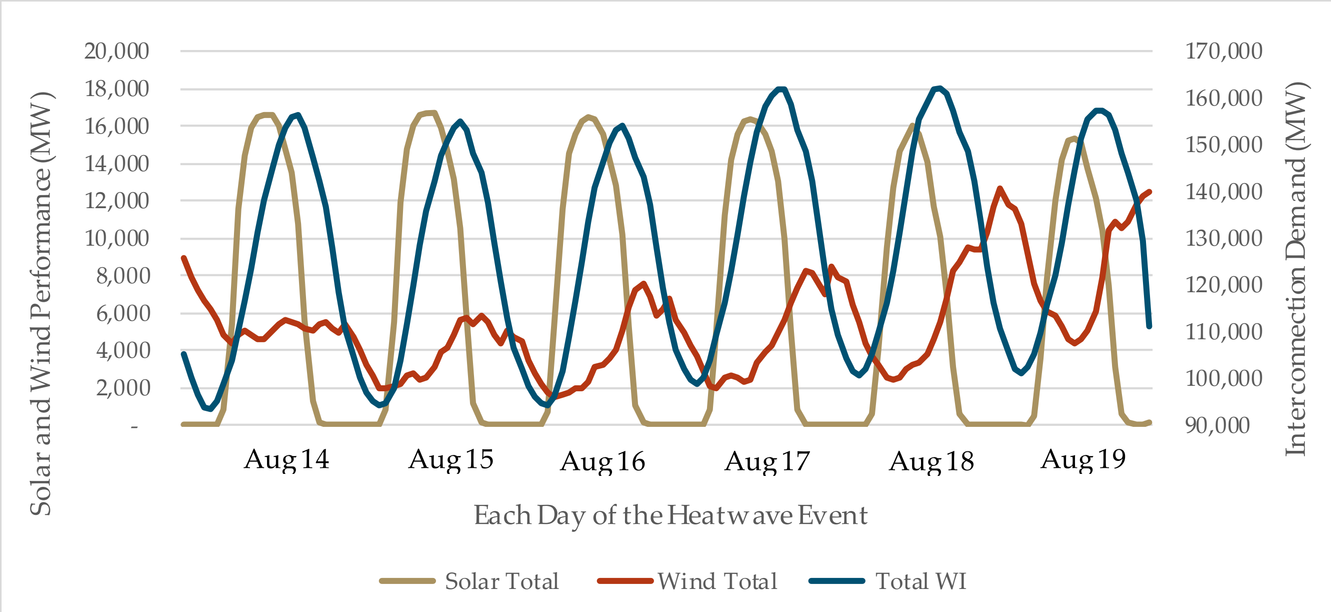
yet to reach their peak generation for the day, requiring the use of other types of generation to meet evening demand.

Figure 6: Variable Generation with Interconnection Demand



As more solar generation is added to the interconnection, the evening ramps, in which solar generation is declining and demand is still increasing, will become more of a reliability challenge. Wind resources tend to generate energy at night but typically not until after the peak demand hour of the day. Without large-scale storage capabilities, entities will need to use thermal resources or rely on real-time markets to meet evening demand. Figure 7 shows that wind production was low during each evening of the heatwave event, and solar generation was declining during the peak demand hours. It was not until the final two days of the event that wind generation surpassed 10,000 MW. Even then, it was after the peak demand hours.

Figure 7: Variable Generation with Interconnection Demand

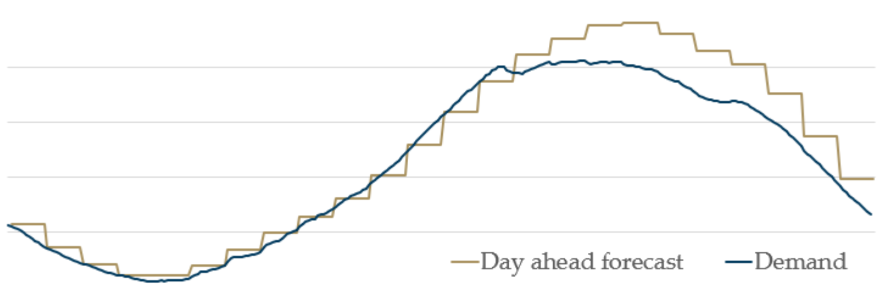


Finding 2—Outreach programs to reduce usage during peak demand hours helped avoid rolling outages.

Outreach programs played a role in avoiding additional outages during the heatwave event. Figure 8 shows the actual demand versus the forecast demand for one BA on August 18, 2020. The system operator in the BA noticed demand was likely going to exceed supply and publicly requested reduced energy usage during peak hours.

Private companies also engaged in public outreach to reduce usage during peak hours. For example, during the heatwave, Tesla sent notice to clients requesting they avoid charging electric vehicles and batteries during peak hours.

Figure 8: Actual Demand vs. Forecast Demand, August 18, 2020



Government actors also effectively reduced usage during peak hours, most notably by requesting the Navy disconnect ships from shoreline power and run them with on-board generation.

Recommendations

Recommendation 1—BAs should become familiar with the WECC Western Assessment of Resource Adequacy report.

Because the heatwave provided real examples of the findings in the *Western Assessment of Resource Adequacy* report, BAs should become familiar with the report to examine how resource adequacy challenges can affect their footprints. In addition, BAs should decide how to incorporate the recommendations in the report to help them prepare for future scenarios.

Conclusion

The August 2020 Heatwave Event provides opportunities for entities and regulators to create a more reliable power grid. Analyzing the effects of prolonged higher temperatures also provides a foundation for strengthening the BPS in anticipation of increasing day-to-day temperatures.

Extreme weather events cause challenges at all levels of the BPS—demand, generation, and transmission. These challenges come from sudden heightened demand and require careful planning and modelling. Not only do demand forecasting methods need to adjust with changing demand patterns, but also strategies to supply that demand need to consider factors beyond traditional resource planning including the variability of resources, the limited generation caused by large increases in demand, the influence of extreme temperatures on certain forms of generation, as well as anticipating congestion on transmission lines.

Through the recommendations in this report, regulators and industry can work together to help ensure a more reliable grid regardless of what challenges the future might bring.