WECC

Western Assessment of Resource Adequacy

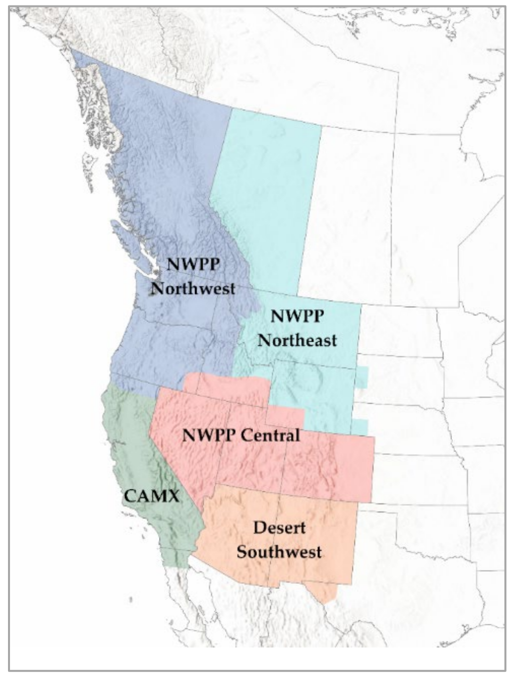
WECC

2022

Executive Summary

The West is experiencing rapid and significant changes in climate, weather, policy, energy consumption patterns, and technology that are challenging the industry's ability to reliably operate and maintain the grid. These changes, coupled with a rapidly transforming resource mix and push for electrification, create risks that will continue to grow over the next decade. These changes are affecting resource adequacy today and are expected to have increasing impacts in future years. There is an urgent need for the West to address resource adequacy issues now.

The Western Assessment of Resource Adequacy (Western Assessment) examines resource adequacy through an energy-based probabilistic approach, looking broadly across the entire Western Interconnection and more specifically within each of five subregions over the next 10 years. This analysis complements other analyses by entities like the Western Power Pool, California Independent System Operator, and others, by providing a high-level look at resource adequacy risks that can help stakeholders target areas for deeper examination and mitigation.[1]



WECC is committed to evaluating evolving trends and risks, conducting comprehensive analyses, and providing unbiased and objective information to industry stakeholders on resource adequacy. WECC's unique interconnection-wide perspective, access to data and resources, and resource-neutral approach make WECC an essential contributor to these discussions.

Drivers of Resource Adequacy Challenges in the West

Severe weather events in the West and elsewhere over the last several years have demonstrated the vulnerability of the power system to resource adequacy risks. In addition, with most western states committed to aggressive clean energy targets and new federal energy policies dedicating billions of dollars to clean energy development, the rapid change in the mix of available resources will continue. That change is likely to increase in magnitude and pace in the future. Over the next decade, entities in the West plan to retire nearly 26 GW of resources, mostly coal and natural gas. During the same time, entities plan to build close to 80 GW of new generation and energy storage resources, over three-quarters of which will be solar, wind, and battery storage. The resource mix in 2032 will look different

[1] Examples of other entities include Energy and Environmental Economics (https://www.ethree.com/e3-webinar-resource-adequacy-in-the-desert-southwest/ and https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf) and the Northwest Power and Conservation Council (https://www.nwcouncil.org/energy/energy-topics/resource-adequacy/).

than it does today, with much higher levels of variability. This is because resources like solar and wind are variable, meaning their energy output changes constantly and there is limited dispatchability. Further, it is not yet clear how factors like electrification, energy efficiency, and new technologies will affect how demand looks and behaves over the next decade. This added uncertainty exacerbates the challenges facing planners and operators.

Findings

WECC uses two measures of resource adequacy risk in its examination of both near-term and long-term resource adequacy in the Western Assessment:

Demand-at-Risk Indicator (DRI): This indicator defines resource adequacy risk strictly as the number of hours in a year when demand is at risk, i.e., where there is a potential that unexpected conditions could cause demand to exceed available generation. This indicator is not a prediction that demand will be lost, it indicates that load is *at risk* of being lost.

Planning Reserve Margin Indicator (PRMI): This indicator is a measure of variability on the system. It defines resource adequacy risk by the reserve margin that entities must hold, given their resource portfolio, to account for variability on the system and meet a one-day-in-ten-year (ODITY), or 99.98%, reliability threshold.[2]

Near-Term Risks

Finding:

Compared to the 2021 Western Assessment results, the DRI (number of hours at risk) decreased, suggesting that the risk for load loss decreased. However, the PRMI has increased, indicating that there is greater variability in the system, which needs to be accounted for to maintain reliability.

Compared to the 2021 assessment, the DRI for the Western Interconnection decreases through 2025 due in part to reductions in the load forecasts in the Pacific Northwest and northern Rocky Mountains, and in part to actions taken after the 2020 heat wave to strengthen resource adequacy. These actions include the addition of almost 3,000 MW of new or expedited resources, the vast majority of which is battery storage, and the delayed retirement of generator resources at plants such as Jim Bridger Powerplant, Haynes Generating Station, and Scattergood Generating Station. Once these plants are retired, the risk returns and will need to be mitigated. Delaying the retirements provides entities more time to determine how to mitigate the risks once these plants retire.

[2] WECC applies the 98.98% ODITY threshold to each hour of the year. Another interpretation of the ODITY threshold is that loss-of-load probability should not exceed 2.4 hours in a given year.

Long-Term Risks

Finding:

Resource adequacy risks increase over the next decade. After 2025, each subregion shows an increase in DRI, due to retirements throughout the next decade. In addition, the PRMI continues to increase. This is primarily due to increasing variability from the addition of large amounts of variable energy resources (VER) and increasing demand variability with record levels of peak demand.

The 2021 Western Assessment showed an interconnection-wide PRMI of 16.9% for 2023. The 2023 PRMI increased to 18.3% in the current assessment. Additional VERs, will cause the PRMI to increase further. If nothing is done to mitigate the long-term risks within the Western Interconnection, by 2025 we anticipate severe risks to the reliability and security of the interconnection.

Managing Resource Adequacy Risks

Increasing Resource and Demand Variability

Finding:

The PRMI increases across the next 10 years because of increasing demand and resource variability. The increase in the PRMI indicates that entities may need to plan for more reserves or take other actions to account for the increased variability. Mitigation actions could include:

- Adding dispatchable resources;
- Increasing demand management measures, e.g., energy efficiency;
- Participating in subregional cooperative efforts, e.g., market, resource adequacy program;
- Supporting the research and development of new technology; and
- Improving coordination of transmission planning and operation.

Finding:

Not only is resource adequacy risk growing, but it is spreading throughout the year beyond the peak load seasons.

Impediments to Building Planned Resources

Finding:

The rate at which entities plan to build new resources over the next decade is comparable to the last decade of resource growth. However, new challenges like supply chain disruption, skilled workforce shortages, and siting issues may impede or delay the build-out of new resources.

Finding:

Considering that the results of this assessment indicate that the number of planned resources may not keep pace with the increases in variability over the next 10 years, any delays in building planned resources could pose serious risks to reliability.

Recommendation—

Resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks. Likewise, commissions must be prepared to consider recovery of costs incurred by the utilities as they plan for increased risks.

Import Availability

Finding:

All subregions rely on imports to help be resource adequate; however, the risk of wide-spread variability could create situations where the imports that entities depend on are not available.

Even with all planned resources built, imports cannot completely mitigate the risk created by increased system variability. Subregions show increasing DRIs over the next decade, which indicates heavy reliance on imports. During some hours, under certain circumstances, these imports may not be available, and any reduction in anticipated imports increases risk.

Recommendation—

The Western Interconnection should evaluate resource and transmission adequacy in a coordinated fashion through comprehensive wide-area system planning.

Recent heat waves have demonstrated that under certain circumstances the ability to move power can be as limiting as the availability of that power. Resource and transmission planning are inextricably linked and need to be considered together on an interconnection-wide basis.

Uncertainty

Finding:

Uncertainty about future impacts to demand of electrification, energy efficiency, new technology, and other factors creates difficulties for load forecasting. As the potential impacts are better understood, entities will likely need to adjust their load forecasts, which has implications for resource planning. The effect this will have on resource adequacy risk is unknown.

Recommendation—

Some entities must evaluate and adapt their resource planning approaches to account for increasing uncertainty.

Traditional methods of resource planning and ensuring resource adequacy rely on predictability. Because historical information was not subject to the increasing variability that we anticipate on the system in the future, it no longer provides a dependable foundation for predicting future system conditions. It is not clear that all entities are taking steps to adapt their approaches.

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Introduction

The heat waves and winter storms the West has experienced over the last several years show that the conditions under which the power system in the West is planned and operated have changed and continue to change. The severe cold weather in Texas and the Midwest in February 2021 served as a stark reminder of the importance of electricity during extreme events and potential life-threatening consequences when it is not available.

The central purpose of the Western Assessment of Resource Adequacy (Western Assessment) is to provide a high-level evaluation of resource adequacy, identify resource adequacy risks to the Bulk Power System (BPS) in the Western Interconnection, and provide recommendations. WECC's resource adequacy work provides a broad perspective on resource adequacy challenges and risks that is meant to complement more detailed work conducted by other entities.

The Western Assessment analyzes hourly resource adequacy trends across the Western Interconnection—and within five subregions—for the next 10 years (Figure 1). The assessment relies on data from Balancing Authorities (BA) describing hourly expected demand and resource projections for that period. It uses an energy-based probabilistic approach that evaluates potential demand and resource availability for each hour over the 10-year study period (2023–2032) to identify instances where there is a risk that demand may not be served.

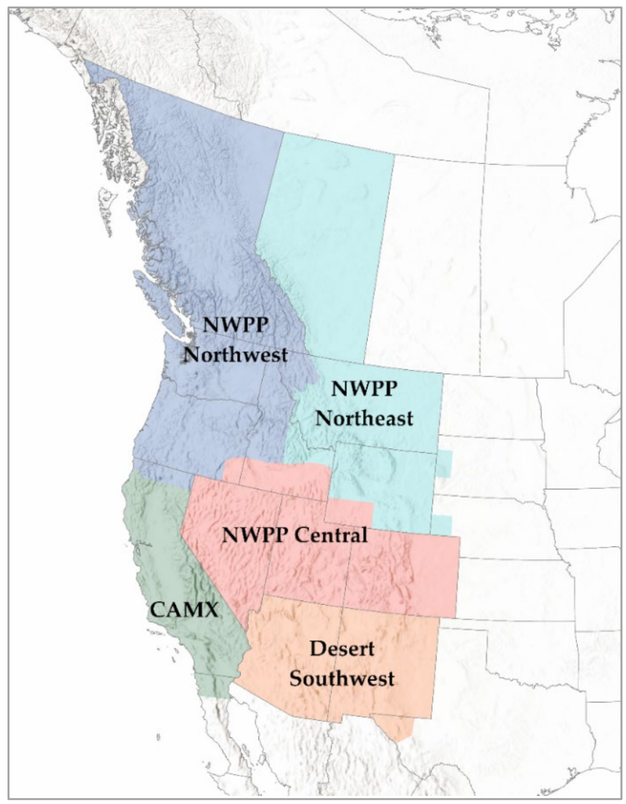

Figure 1: Western Assessment Subregions Map

Variable energy resources (VER) and climate change effects on weather manifest as energy reliability challenges. As more VERs are added to the system and climate change affects weather norms, it is imperative to use both energy- and capacity-based approaches to evaluate resource adequacy. In using an energy-based approach, WECC augments existing analyses that use the more traditional capacity-based approach and offer a different perspective on the resource adequacy issue. Together, the various approaches and resulting assessments create a more complete, multifaceted picture of resource adequacy in the West than any can do alone. WECC is not recommending a replacement of traditional capacity-based approaches but strongly urges resource planners to consider both capacity and energy in their resource planning work.

WECC's Commitment to Resource Adequacy in the West

WECC is committed to facilitating discussions, conducting comprehensive analyses, and providing objective information to regulators and decision-makers on resource adequacy risks. WECC's unique, interconnection-wide perspective, access to data and resources, and resource-neutral approach position WECC to accomplish this work well. WECC will continue working with stakeholders to develop products that provide helpful information, host conversations that inform decision-makers, and gather information to understand industry challenges. The Western Assessment is one example of how WECC provides information to its stakeholders on resource adequacy challenges. For additional information on WECC's resource adequacy work, please visit the Resource Adequacy page on WECC.org.

WECC relies on input from industry, policymakers, and regulators in the West to develop the Western Assessment and is committed to continuously improving its stakeholder engagement in the production and dissemination of its work. WECC would like to thank the stakeholders who provided input and recommendations that helped shape this assessment.

Drivers of Resource Adequacy Challenges in the West

This section describes some of the drivers of resource adequacy challenges in the West and the ways they factor into this assessment.

Energy Policies

Federal Energy Policy

In 2021 and 2022, several groundbreaking federal policies passed that should drive investments and change in the energy sector, specifically toward clean energy targets.

Inflation Reduction Act

The Inflation Reduction Act, signed into law on August 16, 2022, provides $369 billion in funding to encourage clean energy development and reduce carbon emissions. The act will affect both the resource mix and load characteristics through measures such as:

- Various tax credits to accelerate the production of solar panels, wind turbines, and batteries;
- $10 billion investment tax credit for new electric vehicle, wind turbine, and solar panel manufacturing facilities;
- $4.5 billion in direct rebates for low- and moderate-income households to invest in home electrification;
- $4.5 billion rebate program for building efficiency and electrification efforts; and
- $250 billion loan program for infrastructure reinvestment financing to repurpose fossil fuel power plants for clean power generation.

The U.S. Department of Energy (DOE) will oversee permitting and construction of new energy facilities.[3]

U.S. Department of Energy's Industrial Decarbonization Roadmap

In September 2022, the DOE released an Industrial Decarbonization Roadmap that outlines four paths to decarbonization:

1. Energy efficiency via smart manufacturing and advanced data analytics;
2. Industrial electrification by using low-carbon grid power;
3. On-site renewable generation; and
4. Heat pumps.

[3] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

In addition, DOE has urged manufacturers to adopt low-carbon fuels; energy sources; and feedstocks like renewable hydrogen, biofuels, and bio-feedstocks. DOE has also encouraged the deployment of carbon capture, utilization, and storage, including emerging technologies that reuse captured carbon.[4]

Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act, signed into law on November 21, 2021, authorizes and appropriates $9.5 billion for clean hydrogen research, development, and demonstration programs managed by the Secretary of Energy. However, the bulk of this funding, $8 billion, aims to develop four clean hydrogen hubs. At least one of the hubs must use nuclear energy to power electrolyzers, which break water into oxygen and hydrogen through electrolysis, and at least one must use fossil fuels as a feedstock along with carbon capture and storage. Renewables could power the remaining two.[5]

State and Local Energy Policy

In total, clean or renewable energy commitments cover at least 90% of the population in the Western Interconnection (Figure 2). Utah and Arizona aim to have 15–20% renewable energy portfolios by 2025, while six other states plan to cut all carbon emissions by 2040 through 2050. Several cities in the West have also adopted clean or renewable energy targets. These cities include large metropolitan areas such as San Diego, Portland, Denver, Los Angeles, and Salt Lake City. In addition to states and cities, eight investor-owned utilities (IOU) in the West have adopted clean-energy targets from 2030 to 2050.

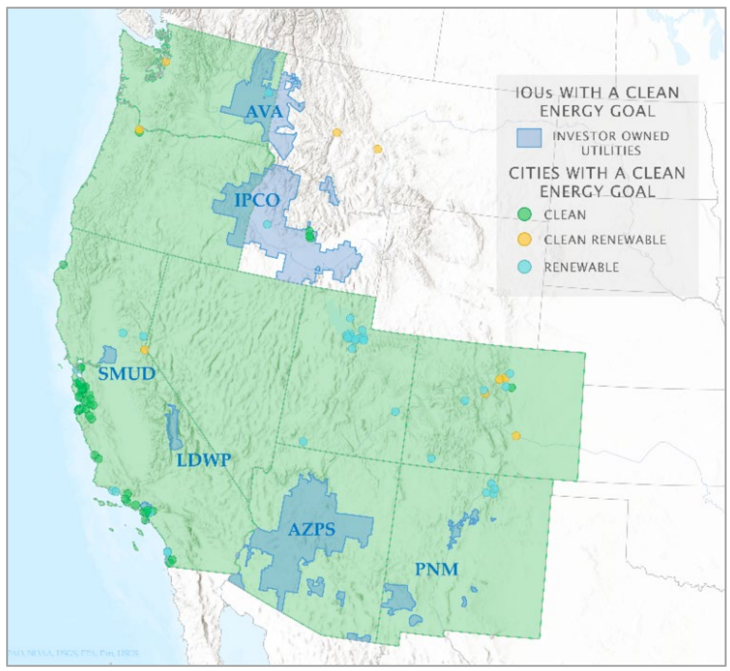

Figure 2: States, large utilities, and cities with renewable or clean energy targets

The data WECC collects from Balancing Authorities reflects their latest resource plans, which include plans to meet policy goals and clean-energy commitments.[6] While WECC does not conduct an

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[4] https://www.energy.gov/eere/doe-industrial-decarbonization-roadmap

[5] https://www.congress.gov/bill/117th-congress/house-bill/3684

[6] Every year, WECC collects historical and forecast (10 years) data on loads and resources from Balancing Authorities in the Western Interconnection.

evaluation of policy goals in this assessment, WECC accounts for the changes caused by energy policies through its probabilistic approach, which allows for examining a wide range of future load and resource possibilities over a 10-year study period to identify instances in which there is a risk of load loss.

Changing Resource Mix

Resource Retirements and Shutdowns

Over the last decade, approximately 23 GW of resources were retired in the U.S. portion of the Western Interconnection. Approximately 18 GW of these retirements have been coal or natural gas resources. Over the next decade, for the entire interconnection, these numbers will increase with the planned retirement of nearly 26 GW (mostly coal and natural gas resources) by 2032 (Figure 3).

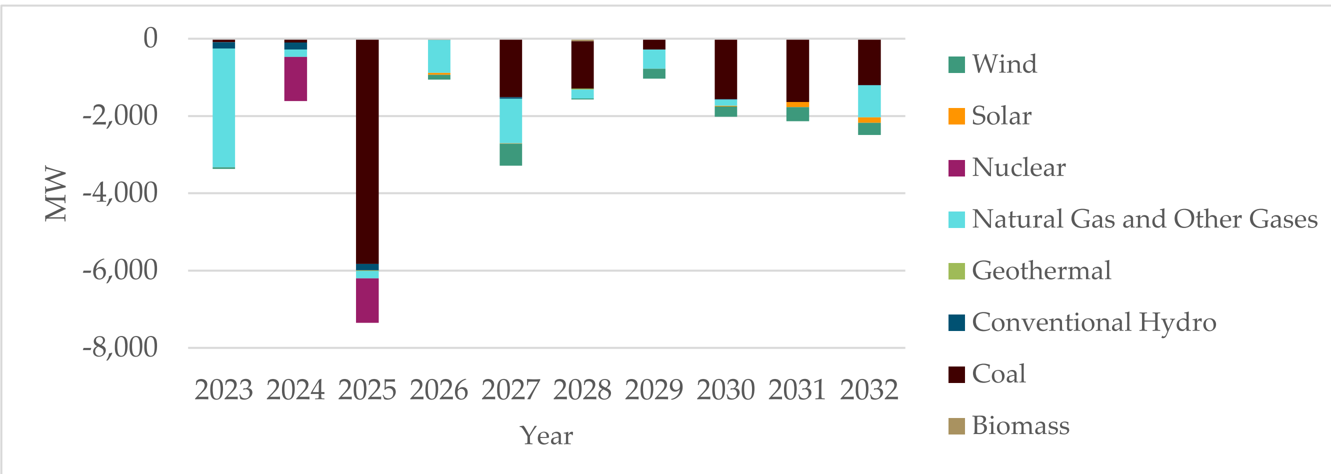

Figure 3: Planned Resource Retirements for the Western Interconnection 2023-2032

Several entities have delayed coal and other resource retirements to make those resources available if necessary, ensuring resource adequacy over the next few years. Figure 4 shows the change in planned retirements between the 2021 and 2022 resource plans. In addition, the 2022 plans show more retirements in later years than the 2021 plans. This reflects that entities regularly update their resource plans to adapt to changes in circumstances and anticipated system conditions.

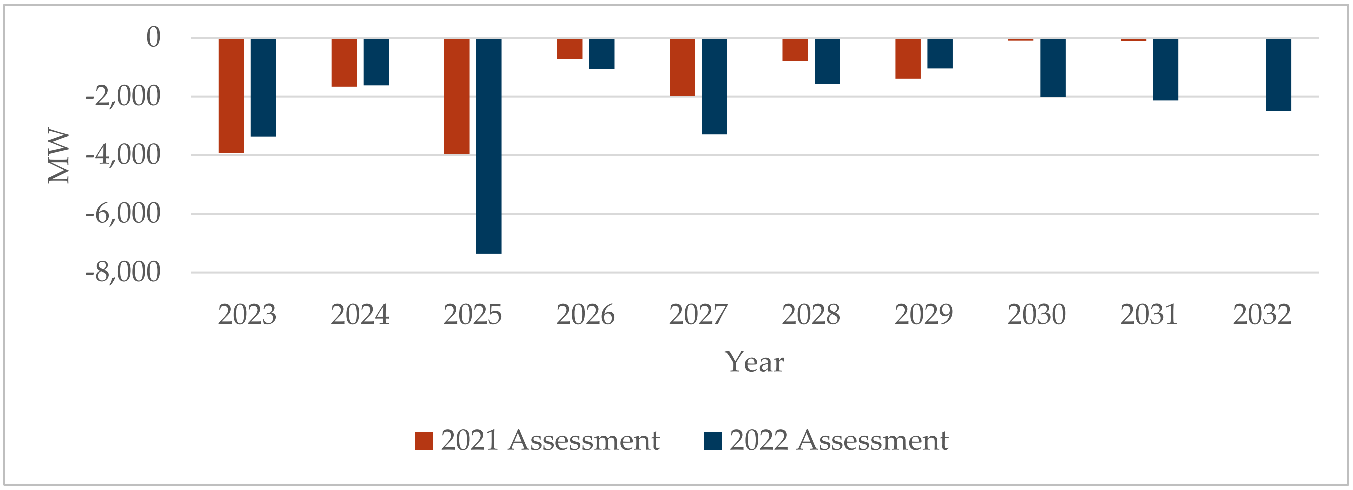

Figure 4: Comparison of Planned Retirements in the Western Interconnection 2023–2032

In addition, while not scheduled for retirement, the future of some hydro resources is uncertain. For example, due to sustained drought at Glen Canyon and Hoover dams, future operation of these hydro resources is uncertain. In 2021 and 2022, these dams, cornerstones of their respective generation fleets, were dangerously close to shutting down due to low water levels. The Bureau of Reclamation took measures in 2021 and 2022 to reduce the water output of Lakes Powell and Mead, which temporarily prevented the shutdown of both power facilities. However, given the West's intensifying drought, it is unclear whether or when these resources will become inoperable due to low water levels.[7]

New Resources

Based on 2022 plans, entities will build close to 80 GW of new resources in the next 10 years.[8] Solar, energy storage, and wind make up more than three-quarters of these new resources (Figure 5).

[7] https://climate.nasa.gov/news/3117/drought-makes-its-home-on-the-range/

[8] The sudden increase in new resources in 2031 is due to more than 25 GW of resources planned in the CAMX subregion that year.

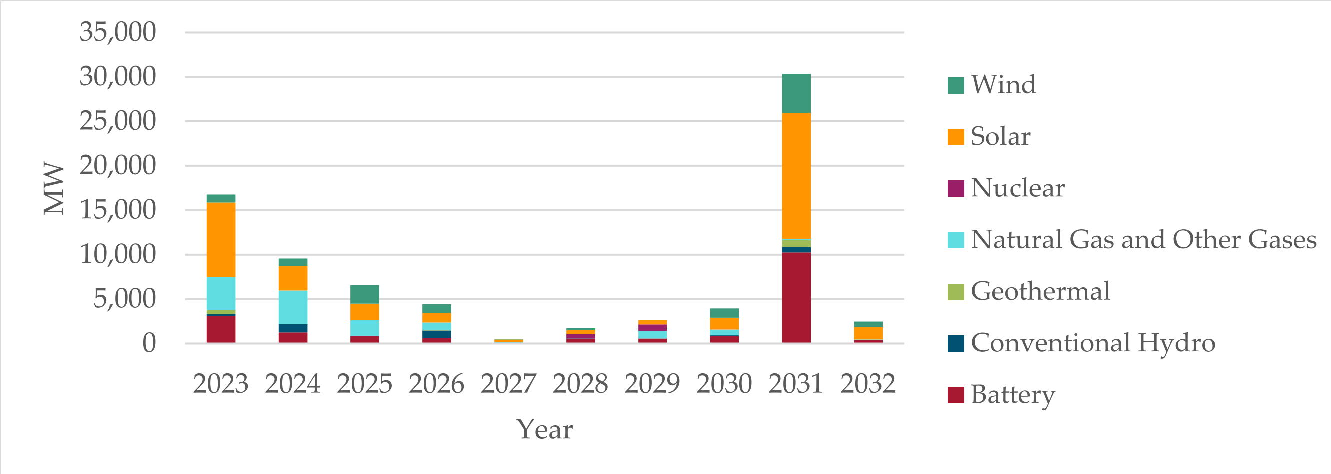

Figure 5: Planned Resource Additions in the Western Interconnection Each Year 2023–2032

Energy Storage

Energy storage continues to gain momentum across the West. While this resource has operational characteristics that can offset some challenges, it is not yet clear how much and what type or duration of storage will help shore up resource adequacy in the interconnection. What is clear is that industry expects significant amounts of energy storage, particularly batteries, to play a role in the future system. Resource plans for 2032 include energy storage at levels almost 14 times more (23 GW) than what was operational in 2021 (1.6 GW) (Figure 6). This means the build rate for storage will have to increase dramatically over the next decade. Federal policy will help advance energy storage proliferation through $2.91 billion in DOE funding for advanced batteries for electric vehicles and energy storage.[9]

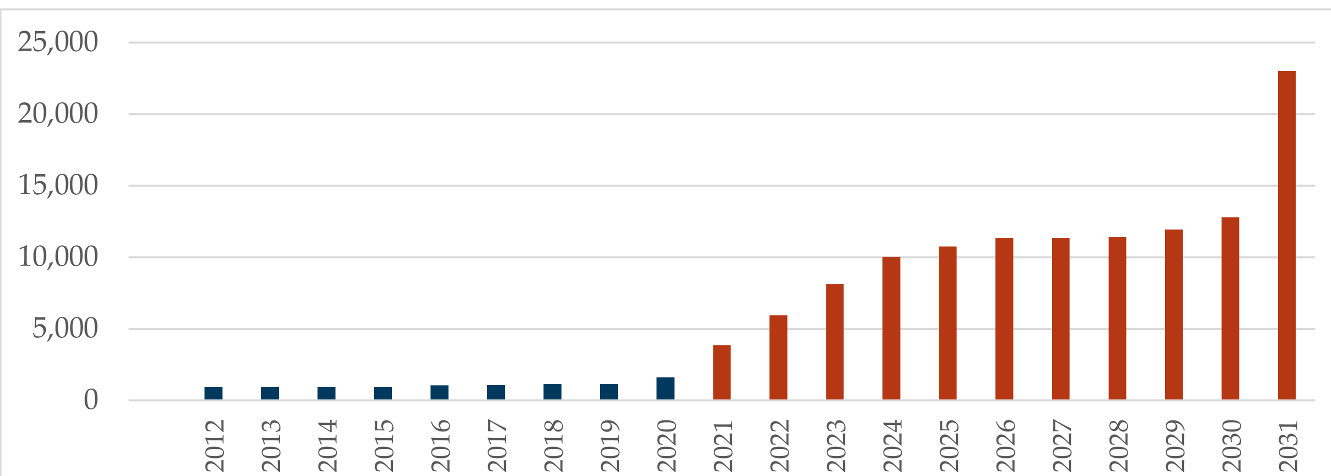

Figure 6: Cumulative Historical and Forecast Total Installed Energy Storage (MW) 2012–2032

[9] https://www.energy.gov/articles/biden-administration-doe-invest-3-billion-strengthen-us-supply-chain-advanced-batteries

WECC includes energy storage in the Western Assessment as a resource based on the data provided by BAs. This assessment does not provide specific findings about the operational role of energy storage in ensuring resource adequacy. WECC studies the impact of energy storage on the system as part of its Study Program.

Changing Load and Demand Patterns

Annual Demand

Based on current load projections provided by BAs, interconnection-wide load growth will remain steady over the next decade. According to 2022 plans, the combined demand for the entire Western Interconnection should grow from 912 TWh in 2023 to 1,107 TWh in 2032—just over an 11.4% increase in a 10-year period.[10] Compared to the 2021 resources plans, the 2022 resource plans show an overall increase in annual energy demand. However, in the Northern regions (NWPP-NW and NWPP-NE), the anticipated annual energy demand in their 2022 resource plans is lower than in their 2021 resource plans (Figure 7). Some NWPP-NW and NWPP-NE BAs adjusted their demand forecasts in the last year to account for new economic and power-use realities in the recovery from the pandemic and associated economic conditions. The adjustments account for a shift from commercial consumption to residential consumption, aggressive conservation and efficiency standards, and economic recession.

[10] For information on load growth in each subregion, see the subregional sections.

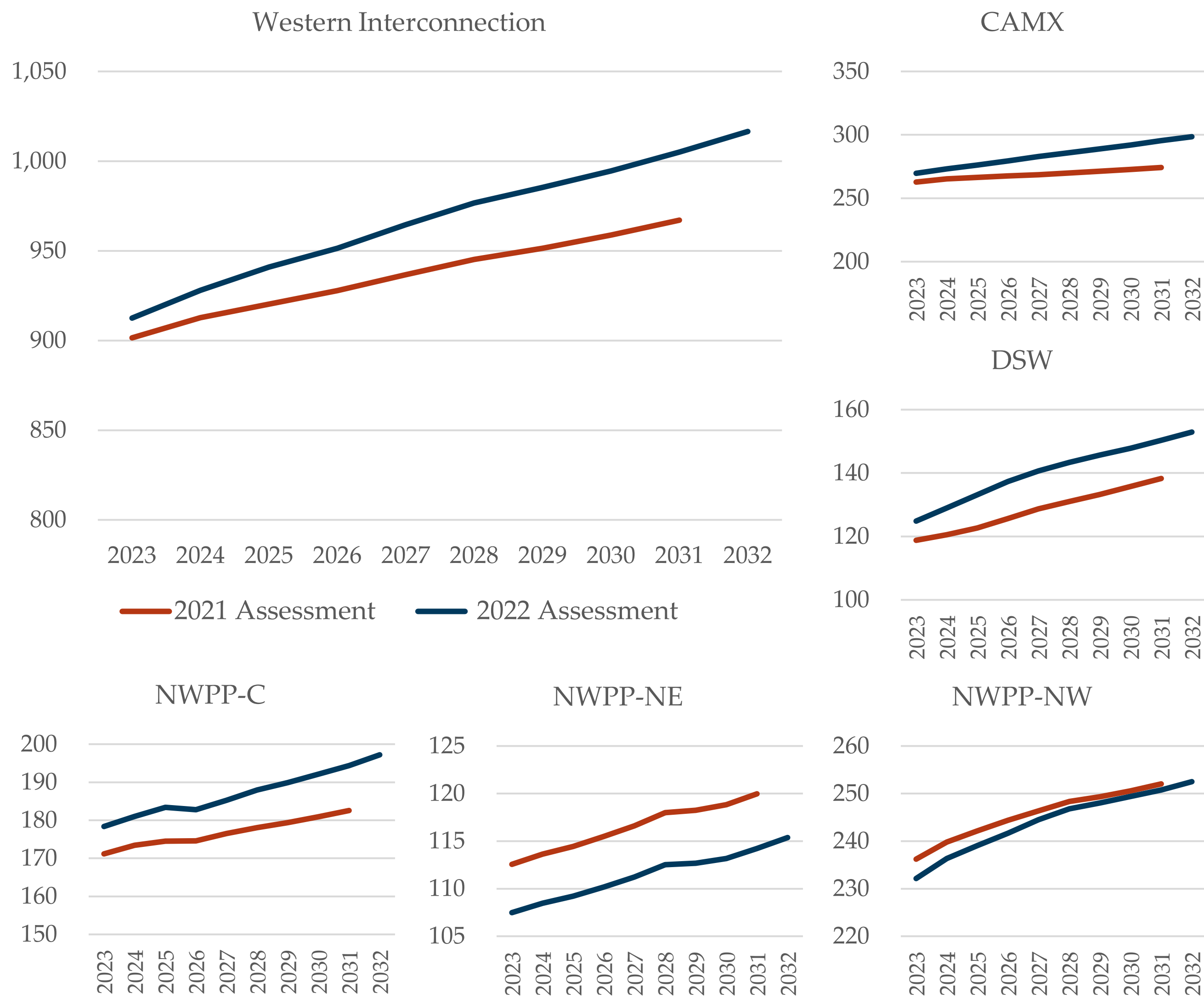

Figure 7: Comparison of Annual Demand Forecasts 2023–2032 (TWh)

Peak Demand

Interconnection-wide peak hour demand occurs in the summer. Based on data submitted by BAs, the peak demand for the Western interconnection is expected to grow from 175 GW in 2023 to 194 GW in 2032, an increase of almost 11%. For the interconnection and the California and Mexico (CAMX), Northwest Power Pool—Central (NWPP-Central), and Desert-Southwest (DSW) subregions, 2022 plans show a slightly higher peak demand than the 2021 plans. However, 2022 plans for the Northwest Power Pool—Northeast (NWPP-NE) and Northwest Power Pool—Northwest (NWPP-NW) subregions generally show a lower peak demand number than the 2021 plans. Overall, the peak hours for the northern regions are consistent with last year's Western Assessment (Figure 8).

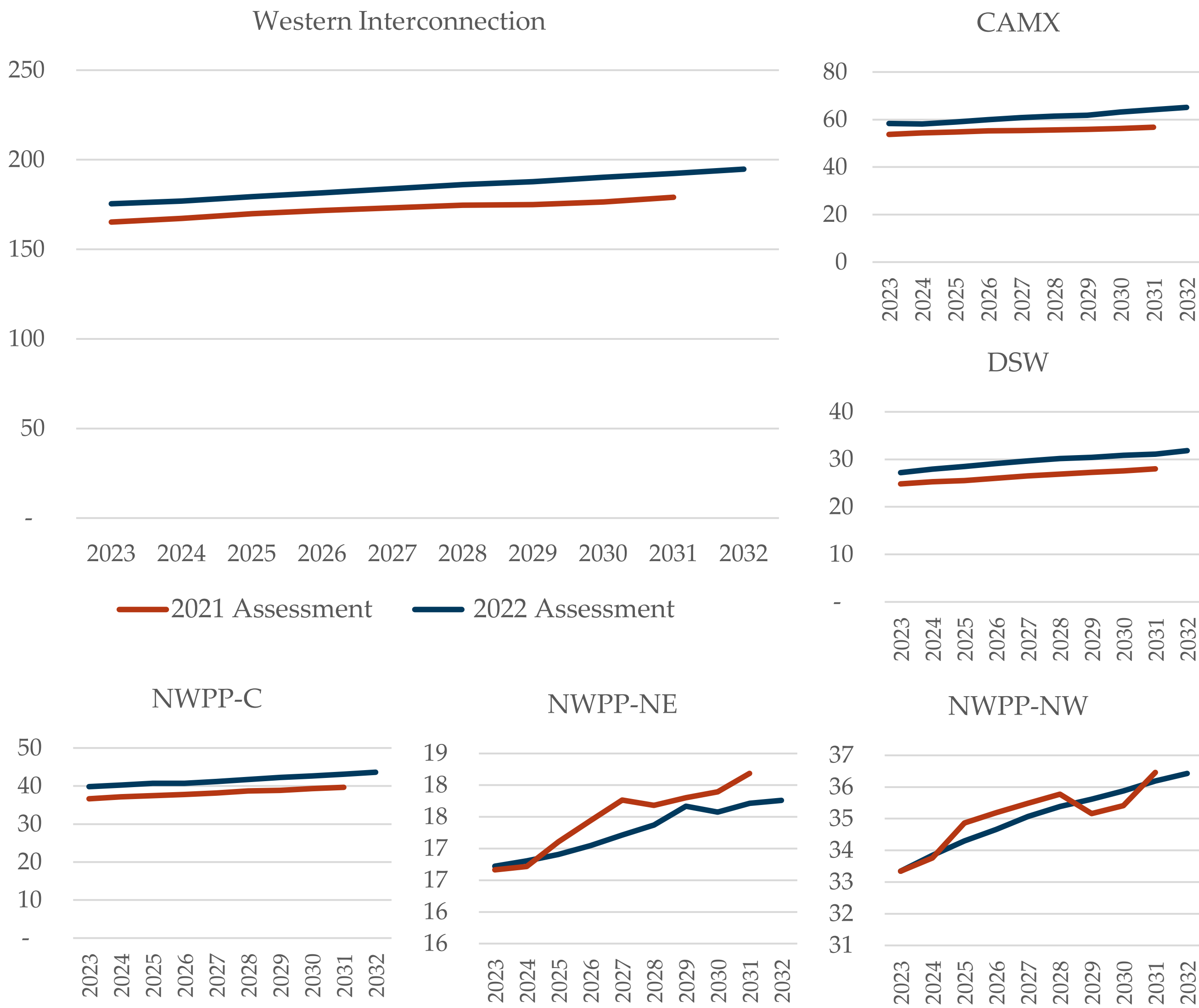

Figure 8: Comparison of Western Assessment Peak Demand Forecasts 2023–2032 (GW)

Severe Weather

Wide-spread, severe weather events challenge our ability to leverage the West's geographic, climate, and resource diversity. For example, during the June 2021 heat wave, maximum temperature records were set in seven different states (CA, AZ, NM, UT, CO, WY, MT) and the Canadian provinces of British Columbia and Alberta.[11] Because events like this cause coinciding demand spikes, they have the potential to reduce or eliminate the ability to move power from less affected areas to areas in need.

[11] Record-breaking June 2021 heat wave impacts the U.S. West | NOAA Climate.gov

Long-term climate patterns also impact demand. Daily temperatures are projected to increase over the foreseeable future (Figure 9).[12] Resource planning entities continue to adapt load forecasts according to new climate projections.

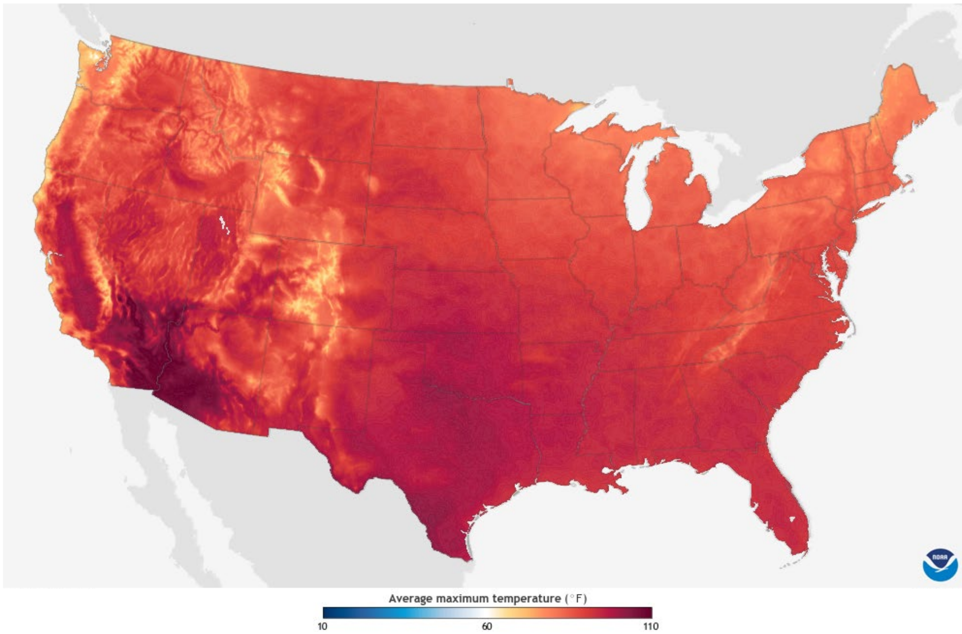

Figure 9: Average Maximum Temperature August 2030-2039

WECC examines the resource adequacy implications of both severe weather and long-term climate changes by looking at how the subregions in the West rely on imports to remain resource adequate during times of high demand.

Electrification

Electrification presents emerging challenges and opportunities to the reliable planning and operation of the system, particularly because it contributes to load growth and affects variability. Over the next 30 years, one source projects national electricity demands will increase by 40%, including about 2,000 TWh of load from EV charging.[13] Entities in the West are just beginning to understand the potential impacts of electrification on the BPS. Electrification could shift and reshape load and change how the system responds to contingencies. BAs do not provide data specific to electrification in their load submittals to WECC; however, BA load forecasts account for the potential effects of electrification on load, to the extent BAs are aware of them. As the potential effects of electrification become clearer, entities will

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[12] Image: https://www.climate.gov/data/Projections--Monthly--Average-Max-Temp-high-emissions--CONUS/02-large/Projections--Monthly--Average-Max-Temp-high-emissions--CONUS--2030-08-00--large.png

[13] https://www.icf.com/insights/energy/impact-electric-vehicles-climate-change

adjust their load forecasts accordingly. While this will certainly affect resource planning, those effects are unclear.

The Past as an Indicator of the Future

Long-standing resource planning practices rely on historical loads, weather, and generation to extrapolate future system behavior. However, historical information is no longer a dependable foundation for predicting future system conditions and challenges. Resource planning methods that rely solely on historical information may not include adequate resources because they do not account for the increasing variability and uncertainty caused by immense change to the system. A recent Western Interstate Energy Board analysis examined the Integrated Resource Plan (IRP) practices of 17 western IOUs to understand how they handle uncertainty and climate change in their resource planning process (Figure 10). Only four entities use both a robust uncertainty analysis and complex modeling to better account for climate change in their resource plans.[14]

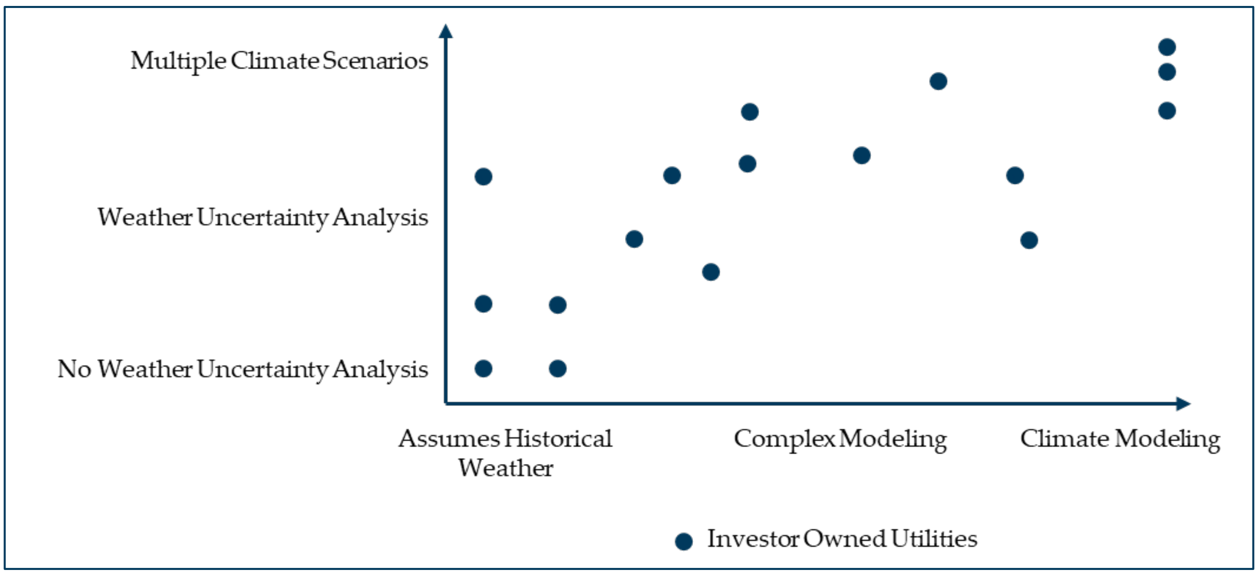

Figure 10: WIEB Uncertainty Analysis and Modeling of Weather Data in IRPs

Evaluating and planning the system for an increasingly uncertain future requires an approach that examines a range of possible conditions and identifies the number of resources necessary to maintain reliability. Probabilistic analysis provides this type of approach. WECC uses probabilistic analysis in this assessment to account for increasing variability on the system.

[14] Figure 10 is an adaptation of a figure presented in the Western Interstate Energy Board's (WIEB) analysis: "Incorporating Temperature and Precipitation Trends in Long-Term Planning." For more information on WIEB's analysis, visit https://www.westernenergyboard.org/wp-content/uploads/Hofgard-Savage-Final-Presentation-8-19-22.pdf.

Link between Transmission and Resource Adequacy

The heat wave in August 2020 stressed the transmission system as the West attempted to move power to meet widespread load increases. In the summer of 2021, the Bootleg fire had a significant effect on the bulk electric system (BES). The fire relayed three major 500 kV lines, resulting in three Energy Emergency Alerts (EEA) Level 3—indicating that firm load interruption is imminent or in progress. This created a situation in which the Western Interconnection was in an open loop and reduced Total Transfer Capacity values for the Pacific DC Intertie. These disruptions demonstrate the challenges of moving power across the system under certain conditions like extreme heat and wildfire, both of which can also create resource adequacy challenges.

WECC recommends that utilities evaluate resource and transmission adequacy in a coordinated fashion. Traditionally, resource and transmission planning have occurred as two distinct disciplines because of the jurisdictional considerations for approval of each. Also, transmission capacity and resource adequacy require different subject matter expertise. However, as resource adequacy and transmission challenges and risks intersect, comprehensive approaches that consider both elements on an interconnection-wide basis can help entities plan a resource- and transmission-adequate system that can withstand extreme weather events.

WECC did not use a highly detailed topology to represent the transmission system in its modeling for this assessment due to modeling run-time constraints. However, transmission constraints between load-serving areas were accounted for in the model. WECC uses various tools and methods applied to deterministic scenarios to study transmission adequacy during extreme events such as heat waves.[15]

Analyzing Resource Adequacy Risk

This section focuses on answering two questions:

1. Are current resource plans sufficient to meet demand forecasts over each of the next 10 years given the range of possible system conditions?
2. How do the anticipated changes in resources and demand currently reflected in resource plans affect the levels of reserves entities must hold to cover the variability on their system, and what does this say about resource adequacy risk?

WECC uses two resource adequacy risk measures to answer these questions. The first measure defines *resource adequacy risk* strictly as the number of hours in a year when demand is at risk (demand-at-risk hour), i.e., where there is a potential that unexpected conditions could cause demand to exceed available generation. Based on this definition, the Western Interconnection shows a reduction in risk

[15] For more information on these analyses, see https://www.wecc.org/RAC/Pages/StS.aspx#2020-2021StudyProgram.

over the next few years and an increase over the long term (See the Demand-at-Risk section below). This is mainly due to urgent risk-mitigating actions taken in the last two years, such as delaying resource retirements and expediting new resources. However, when the retirement delays lapse, the removal of these resources will cause an increase in the number of demand-at-risk hours.

The second measure defines resource adequacy risk by the reserve margin that entities must hold to reduce or eliminate demand-at-risk hours given a specific resource portfolio. Higher levels of variability correlate to higher levels of risk. Entities with high system variability must carry a higher reserve margin. Measuring reserve margins over time is one way to track how resource adequacy risks change. When measured this way, this assessment shows that overall risk to the Western Interconnection continues to increase rapidly due to increasing demand and resource variability over the next 10 years.

Demand-at-Risk Analysis

One way that WECC measures resource adequacy risk is by analyzing the number of hours in a year when there is a risk for potential load loss (demand-at-risk hour). A demand-at-risk hour is one in which the risk for potential load loss caused by unexpected conditions exceeds the load loss of one-day-in-ten-years (ODITY) or 99.98% reliability threshold. WECC uses an indicator called the Demand at Risk Indicator (DRI) to measure these hours. WECC calculates the probability that demand might be shed for any given hour, and if that probability is greater than the ODITY threshold, that hour is counted.[16] This indicator is not a prediction that demand will be lost, it indicates that load is *at risk* of being lost.

To allow an analysis of the effect of imports and new resources on demand-at-risk hours, WECC examines the DRI under three sets of conditions:

1. ***All Planned Resources with Imports:*** This scenario reflects the expected resource additions and imports in current resource plans;
2. ***No New Resources with Imports:*** This scenario highlights the challenges facing the West if new resources are not built; and
3. ***All Planned Resources without Imports:*** This scenario evaluates the role of imports in ensuring resource adequacy.

[16] The ODITY threshold is the risk tolerance threshold WECC uses for its resource adequacy analysis. To meet the ODITY threshold, the risk that load may be shed in any given hour must not exceed .02%, making that hour 99.98% reliable. For more information on WECC's demand-at-risk methods and the ODITY threshold, see https://www.wecc.org/ResourceAdequacy/Pages/default.aspx#Resources.

Overall Findings

Generally, compared to the 2021 Western Assessment results, near-term resource adequacy risks through 2025, as measured using the DRI, decline across the Western Interconnection. The Interconnection will have less than 25 demand-at-risk hours annually over the next three years. This shift is due to reductions in demand forecasts, additions of new resources, and delayed retirements of some resources.[17] However, after 2025, the DRI for the Western Interconnection increases. Additionally, each subregion's DRI increases over the next 10 years, even with additional planned resources and imports—primarily due to increasing load forecasts and the incorporation of new extreme weather events that affect the variability around these forecasts.

Without previous actions by states and companies to delay plant retirements, the DRI would likely have been much higher. While these actions did reduce short-term resource adequacy risks, they are temporary. Once the retirement delays expire, a lack of additional action to strengthen resource adequacy will result in returning risks.

In the longer term, to mitigate the increase of resource adequacy risks, entities plan to add new resources to their portfolios. While entities plan to add a significant amount of capacity over the next decade, that capacity is largely VERs, which add additional variability to the system. This lowers the DRI since energy is being added to the system; however, the additional variability from the added VERs actually increases the risk, as measured with the Planning Reserve Margin Indicator (PRMI) described in the next section. This is the case in CAMX and the Northwest subregions. Imports additionally help reduce the DRI for all subregions by allowing them to rely on the Western Interconnection's diversity. However, there is a risk of overreliance on imports to satisfy resource adequacy requirements. Imports have an enormous impact on resource adequacy risk. Comparing all scenario results, when subregions can import power, the DRI decreases significantly, underscoring the importance of transmission to resource adequacy.

Note that, in some cases, the DRI could decrease due to the inclusion of speculative resources that are not yet approved in entity integrated resource plans. Typically, these resources are added by entities as a place holder to demonstrate their resource adequacy in the long-term because the details of the added resource are not yet known.

Scenario 1: All Planned Resources with Imports

All five subregions show some demand at risk over the next 10 years, based on the 2022 resource plan information provided to WECC. However, compared to the resource plans analyzed in the 2021 Western Assessment, the DRI for each subregion has changed (Figure 11 and Figure 12).

[17] The Western Assessment is based on the Loads and Resources data WECC receives from Balancing Authorities in the first quarter of the year.

Findings

All subregions show a lower DRI through 2025 based on 2022 resource plans than they did for 2021 resource plans. These results are due to reductions in demand forecasts, the addition of new resources, and in the case of CAMX, NWPP-NE, and NWPP-NW, the delayed retirement of approximately 2,080 MW of resources, including units at Jim Bridger Power Plant, Haynes Generating Station, and Scattergood Generating Station.

- In 2031, the CAMX DRI drops significantly, which coincides with large additions of resources planned that year (Figure 11).
- While the CAMX and Central subregions show improved DRI compared to the 2021 Western Assessment, both subregions show continued growth in their DRI until 2031 and 2032, respectively.
- The DSW subregion shows some improvement in its DRI through 2025 compared to the 2021 Western Assessment. This is largely due to new resources. However, starting in 2026, the outlook for the DSW based on 2022 plans is worse than it was based on 2021 plans.

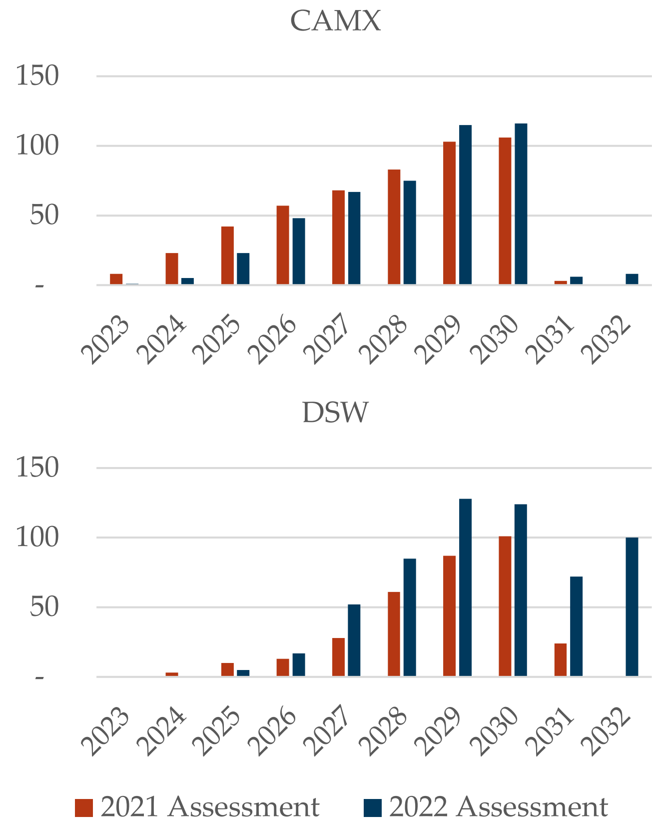

Figure 11: DRI with New Resources and Imports (Hours)

- The Central subregion has the highest DRI over the next 10 years, exceeding 650 hours in 2032 (Figure 12).
- DRI improvements for the NWPP-NE and NWPP-NW subregions extend across the next decade, with each showing substantial DRI decreases compared to the 2021 Western Assessment. Both subregions maintain a relatively low DRI over this time.
- A reduction in demand forecast in the NWPP-NE subregion drastically improves its DRI compared to the 2021 Western Assessment. For the reported demand-at-risk hours in this subregion, the majority are made up through contracts that are not included in this analysis. This means that the hours at risk in the 2021 Western Assessment were very high. The reduction in demand forecasts for the 2022 Western Assessment eliminate most of these hours at risk.[18]

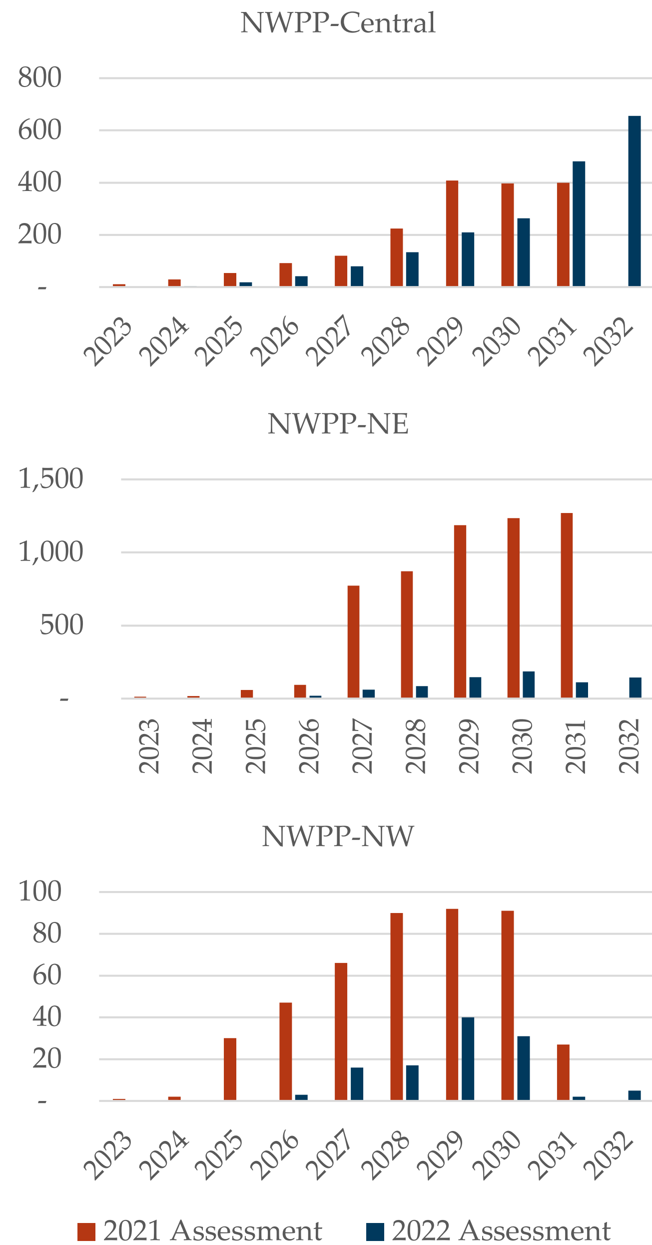

Figure 12: DRI with New Resources and Imports (Hours)

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[18] Some NWPP-NW and NWPP-NE BAs adjusted their demand forecasts to account for new economic and power use realities in the pandemic and economic recovery phase. The adjustments account for a shift from commercial consumption to residential consumption, aggressive conservation and efficiency standards, and economic recession.

Scenario 2: Imports but No New Resources

The addition of new resources to the system improves the DRI number by adding more energy into the system, which entities can rely on to mitigate variability. Assessing the DRI without new resources establishes a baseline that can be compared to Scenario 1. This comparison illustrates the influence of new resources (versus imports) in ensuring resource adequacy and underscores the importance of building planned resources.

Findings

Without new resources—any resource not in operation at the end of 2021—and given the expected growth in demand, the DRI for all subregions is an order of magnitude higher than in Scenario 1 and increases uniformly over the next decade (Figure 13 and Figure 14). Lower demand forecasts in the NWPP-NW and NWPP-NE subregions shifted the increase in DRI out two to three years compared to the 2021 Western Assessment. However, generally, the results are comparable to the 2021 Western Assessment for all subregions. Compared to the DRIs in Scenario 1, the results of this scenario highlight the importance of new resources because, when new resource were removed, the DRI in each subregion increased significantly.

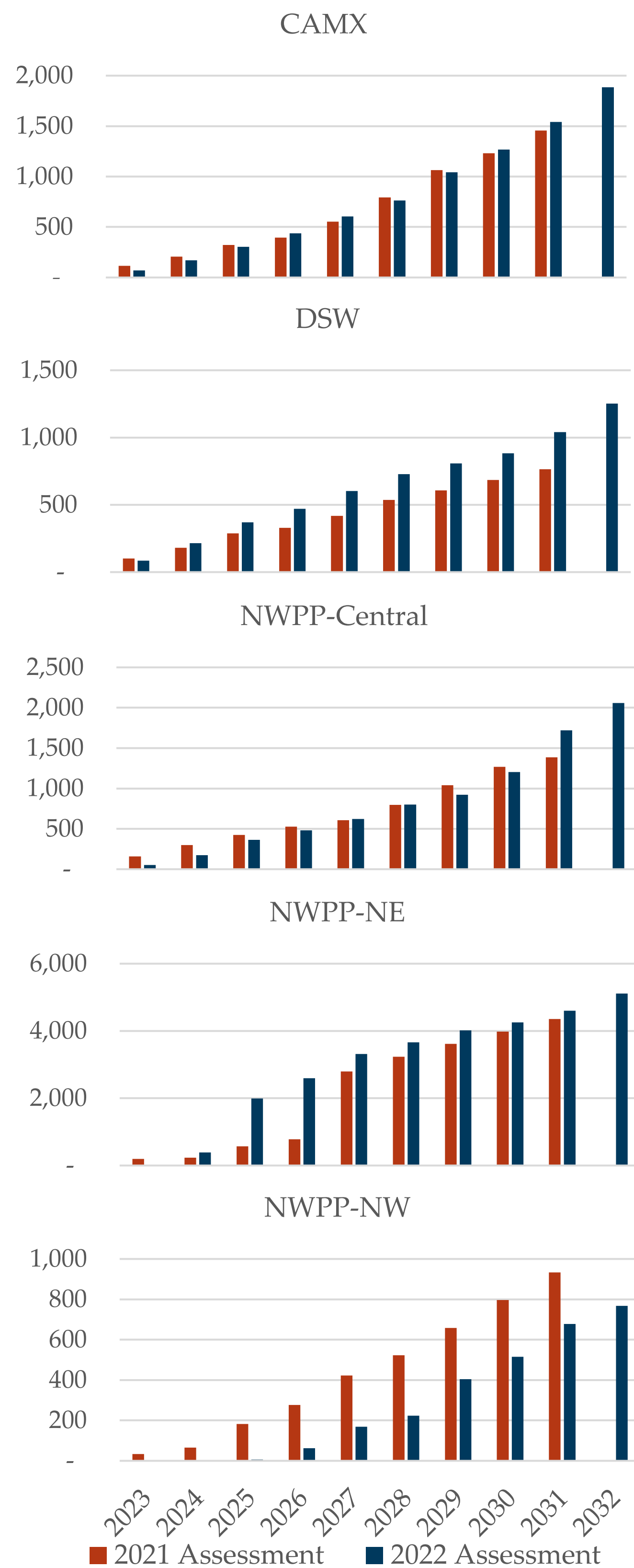

Figure 13: DRI with Imports but No New Resources (Hours)

Scenario 3: All Planned Resources but no Imports

The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint. However, an over reliance on imports can lead to resource shortfalls during widespread events and extreme conditions. The purpose of this scenario is to examine the role of imports in maintaining resource adequacy by removing the ability to import power across subregional boundaries and evaluating the DRI under those circumstances.

Findings

- When the ability to import power is removed, the DRI increases drastically for all subregions over the next ten years (Figure 14).
- While CAMX and DSW subregions also show growth in their DRIs over the next decade, their DRIs are lower in this scenario than in Scenario 2.
- Compared to the 2021 Western Assessment, the Central subregion has seen a decline in the number of DRI hours because of new resources that were not in last year's plan. On the other hand, CAMX and the DSW have seen substantial increases in their DRIs because these subregions include much more renewable resources than other types such as natural gas.
- In the NWPP-NE, NWPP-NW, and NWPP-Central subregions, the DRI in this scenario is two to three times higher than in Scenario 2, where there were no new

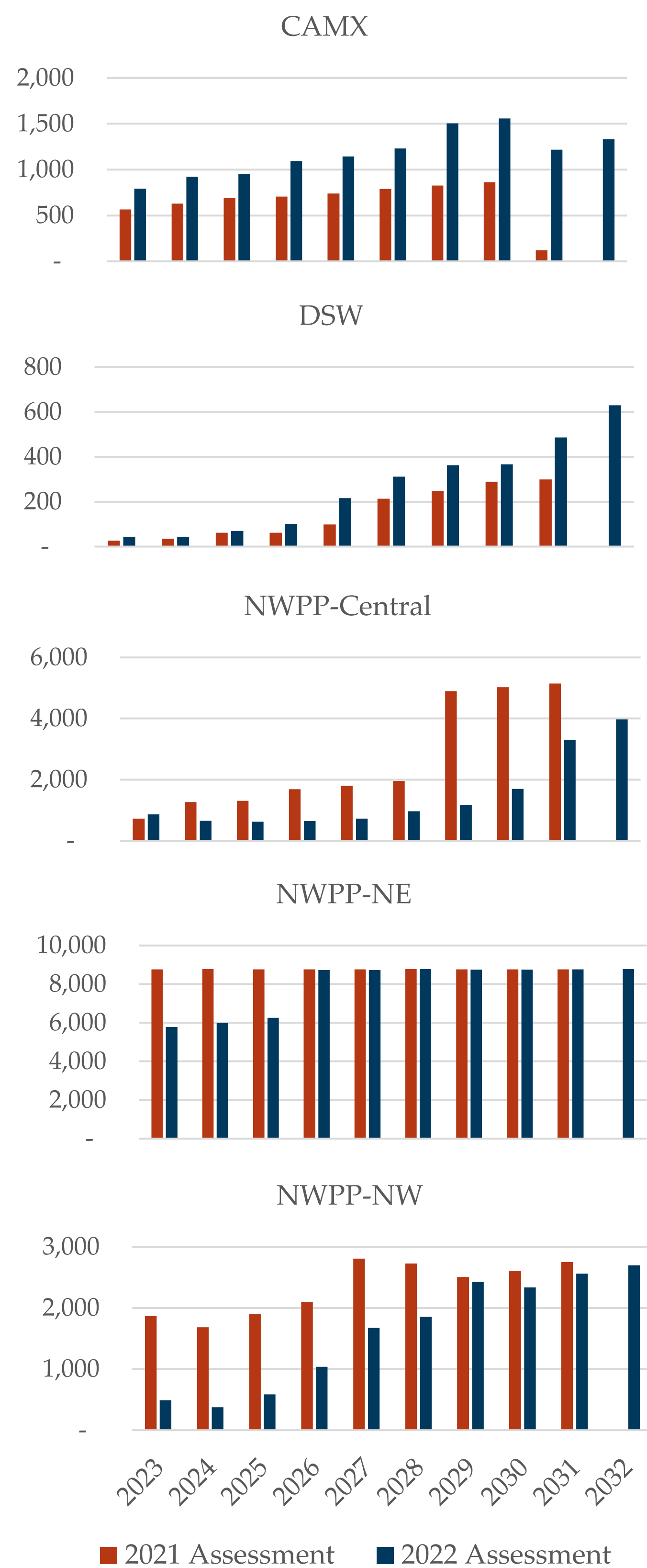

Figure 14: DRI with New Resources but No Imports (Hours)

resources. This suggests that, for these subregions, a lack of import ability is more impactful than a lack of new resources. This may be due to the fact that, in the winter months, these subregions will increasingly rely on imports from the rest of the interconnection to manage the variability they are adding to their systems with new VERs.

Planning Reserve Margin Analysis

In addition to the DRI, WECC defines resource adequacy risk by the reserve margin necessary to keep an entity's resource portfolio within the ODITY threshold. All entities' resource plans sufficiently cover their expected load with the generation they expect from their existing and planned resources. However, load and generation rarely occur according to expectations, so entities must be able to manage deviations, which they do with a reserve margin. All entities include some reserve margin in their resource plans, but how entities calculate the margin necessary to manage deviations from their expected load (demand variability) or expected generation (resource variability) varies widely.

Variability on the system creates risk. While all systems have some variability, higher levels of variability are generally associated with higher levels of resource adequacy risk. The reserve margin an entity must carry to cover its demand and resource variability is one way to measure its resource adequacy risk. Entities with high variability on their systems must carry a higher reserve margin than those with lower variability. Therefore, while an entity's resource plan may include enough capacity to cover their expected load, the entity may have to hold a very high reserve margin to cover its demand or resource variability. WECC analyzes the reserve margins to track the resource adequacy risks in entity resource plans.

Resource planning entities include a Planning Reserve Margin (PRM) in their process. Typically, entities use a set PRM, adding resources to the planned mix until they cover peak load plus the PRM. Assuming the PRM is sufficient to cover the variability on the system being planned, this method is adequate. However, WECC's work indicates that, given the high levels of variable generation planned on the system in the next 10 years, existing PRMs will not be sufficient to cover the increased variability of the system in most cases.

Planning Reserve Margin Index

To evaluate the sufficiency of PRMs over the next decade, WECC reverses the process entities use. Starting with its expected demand and resources for a given year, WECC uses probabilistic analysis to determine the level of variability on an entity's system. From there, WECC calculates the level of reserve margin the entity would need to cover the variability and satisfy the ODITY threshold for each hour of any given year. WECC calls this the Planning Reserve Margin Index (PRMI), because WECC does not have the information necessary to accurately prescribe a PRM.[19] The PRMI is an indicator of the level of variability on a given system, taking into consideration the resource and demand characteristics of that system. Tracking the PRMI over time allows WECC to identify changes in the relative level of variability—and therefore risk—on the system. This section compares PRMIs from the 2021 Western Assessment and this year's assessment.

WECC's results from the PRMI analysis can be displayed on a duration curve (Figure 15). This curve shows the reserve margins necessary to satisfy the ODITY threshold for each hour of the year, accounting for the variability (potential deviation from expectations) for each hour. The data is shown in descending order, with the largest reserve margin at the Y-axis, descending to the right. In addition, each point on the curve is associated with a level of demand (in megawatts) and number of hours at risk.

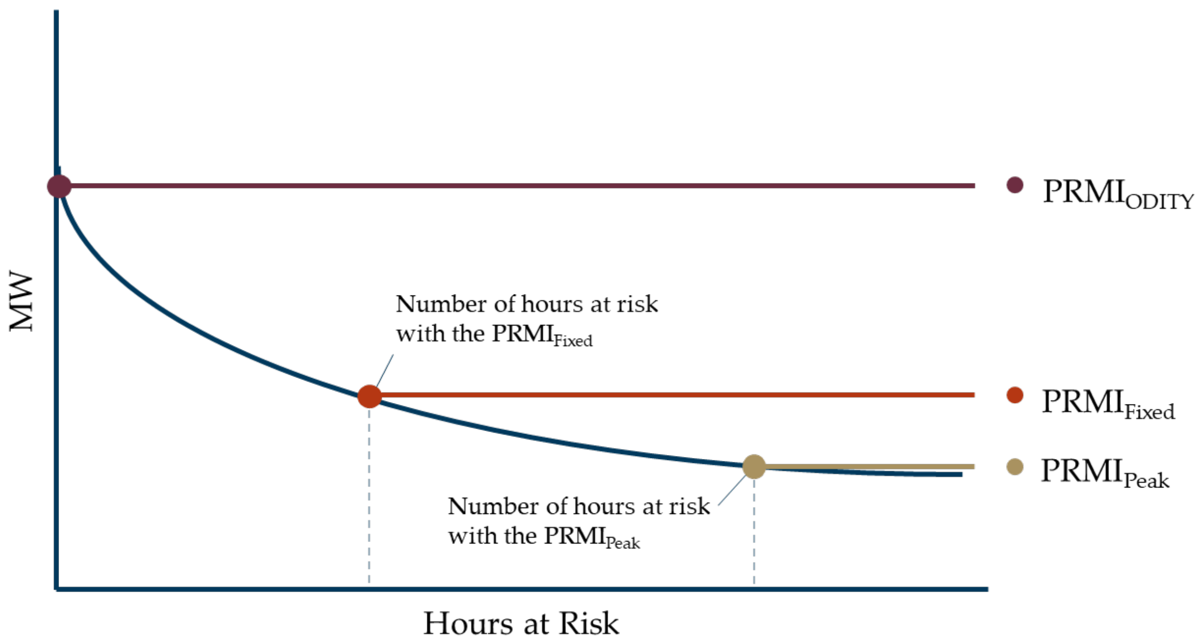

Figure 15: PRMI Duration Curve Example

[19] WECC's data includes information available in entity resource plans but does not include contractual or other granular information necessary to calculate an actual Planning Reserve Margin.

For its analysis of the sufficiency of planning reserve margins, WECC picks three points on the curve to examine:

- **PRMI$_{\text{Fixed}}$**: This point corresponds to a generic 15% planning reserve margin, selected because it is a commonly used reference for planning reserve margin analyses.[20] The PRMI$_{\text{Fixed}}$ provides insight into how much demand may be at risk in any given year assuming an entity's planning reserve margin is fixed at 15% of its peak demand for that year.
- **PRMI$_{\text{Peak}}$**: This point corresponds to the planning reserve margin an entity would hold if they calculated it based on the peak demand hour of the year being assessed.[21] The PRMI$_{\text{Peak}}$ provides insight into how much demand may be at risk in any given year assuming the PRM for the area in question is calculated based on that area's peak demand hour.[22]
- **PRMI$_{\text{ODITY}}$**: This point corresponds to the planning reserve margin necessary to ensure the ODITY threshold is met, i.e., in any given year all hours are 99.98% reliable, meaning there is less than .02% chance that there is a loss of load for each hour. When compared to other PRMIs, the PRMI$_{\text{ODITY}}$ demonstrates how much increase in reserves may be necessary to maintain resource adequacy at the ODITY threshold in the given year.

WECC's data includes information available in entity resource plans but does not include contractual or other granular information necessary to calculate an actual PRM for any entity. In addition, WECC recognizes that PRMs do not exist for subregions or the entire interconnection. Therefore, the PRMI$_{\text{ODITY}}$ should be viewed as representing the gap between where a subregion is in addressing the variability on its system (including its current PRM) and where it needs to be to meet the ODITY threshold. Increasing the PRM target is one way to address this gap, but there are other actions that entities can take, including demand management, participation in subregional cooperative mechanisms, and importing energy.

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[20] At one time, resource planning entities used a fixed PRM in their planning work to ensure their resources could adequately cover demand and any extreme circumstances. Fifteen percent was the PRM typically used, which is why WECC sets its PRMI$_{\text{Fixed}}$ to 15%.

[21] Over time, industry began to use the annual peak demand hour to determine PRMs. This approach is based on the reasoning that, if the hour with the greatest stress (peak demand hour) is covered by the PRM, then all other hours will be covered. This is an approach still in use today.

[22] However, as variability increases, off-peak hours are experiencing more strain as the system works to adapt.

With the addition of variable resources and growing variability in climate and weather, system variability is increasing, and the peak hour is no longer necessarily the most stressed hour of the year. This means that in some cases, planning to the annual peak hour will not sufficiently address the variability on the system. In response, some planning entities are beginning to shift their approach to focus on covering the variability on the system over the entire year, as opposed to just the peak hour. WECC's PRMI$_{\text{ODITY}}$ reflects this approach because it refers to the PRM necessary to cover the total variability across the year.

PRMI Trends

Compared to the results of the 2021 Western Assessment, the PRMI$_{ODITY}$ for the Western Interconnection has increased from 16.9% to 18.3% (Figure 16). This indicates that variability on the system has increased, due primarily to increased variable resources. If entities continue to add variable resources, the increase in the PRMI will continue. Planning entities should take actions to mitigate the increasing variability and resulting adverse impacts to reliability. These actions could include:

- Adding dispatchable resources;
- Increasing demand management measures, e.g., energy efficiency;
- Participation in subregional cooperative mechanisms, e.g., market, resource adequacy program; and
- Improving coordination of transmission planning and operation.

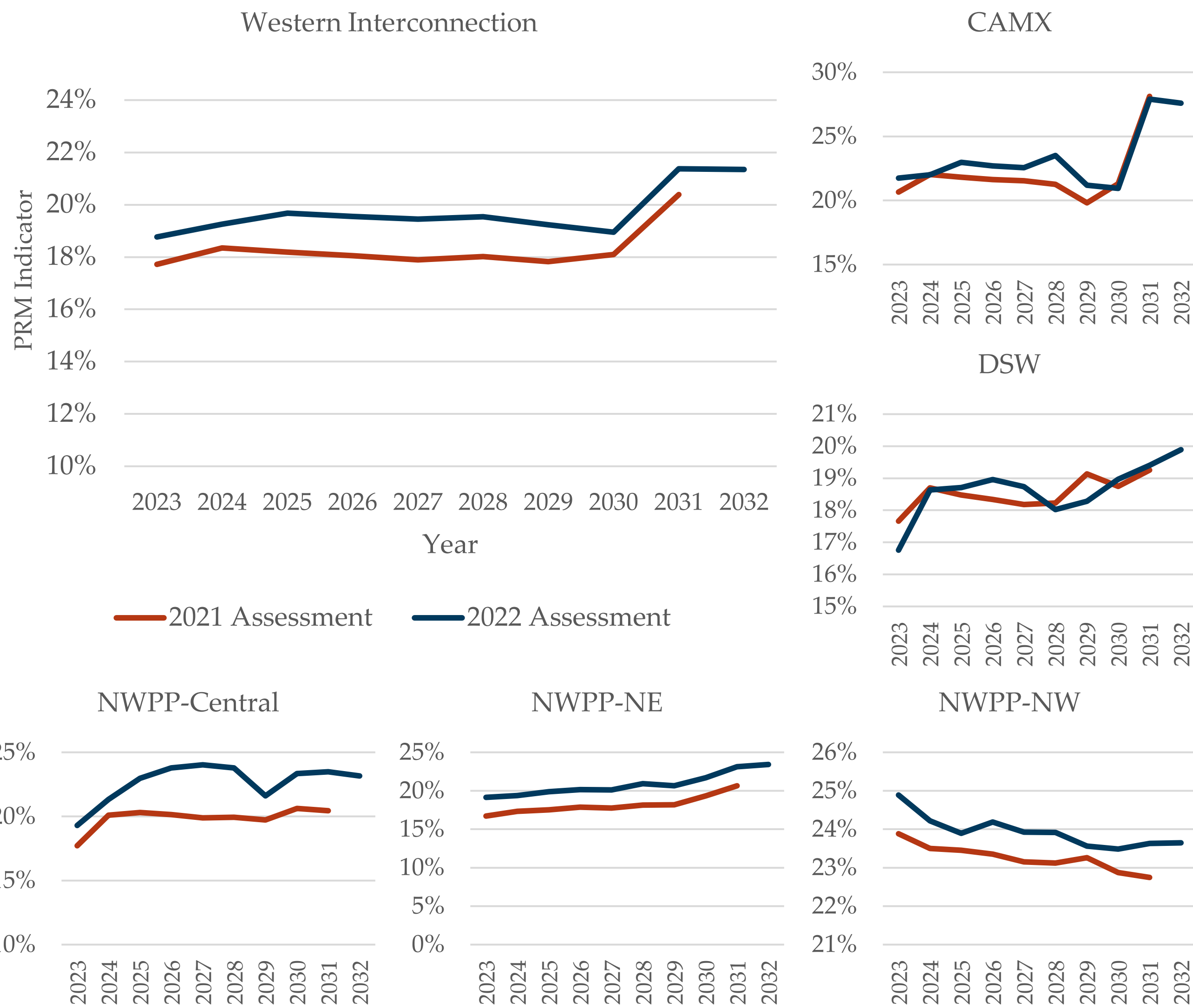

Figure 16: Western Interconnection and Subregional PRMI$_{ODITY}$ Trends

PRMI Comparisons

A comparison of the $PRMI_{ODITY}$ to the $PRMI_{Peak}$ shows how well entities are addressing system variability when they use the peak demand to determine their PRMs (Figure 17). Interconnection-wide, the 2023 $PRMI_{Peak}$ is 15.6%. This leaves 312 hours where demand is at risk because they do not meet the ODITY threshold. To meet the threshold, the interconnection would need to attain the $PRMI_{ODITY}$ of 18.3%. To close the gap between the $PRMI_{Peak}$ and $PRMI_{ODITY}$, the interconnection would have to increase its reserve margin. There is no interconnection-wide reserve margin for resource adequacy, but these numbers indicate that, as a whole, the West is not holding enough reserves to cover variability and meet the ODITY threshold if entities use the peak demand hour to calculate their PRMs.

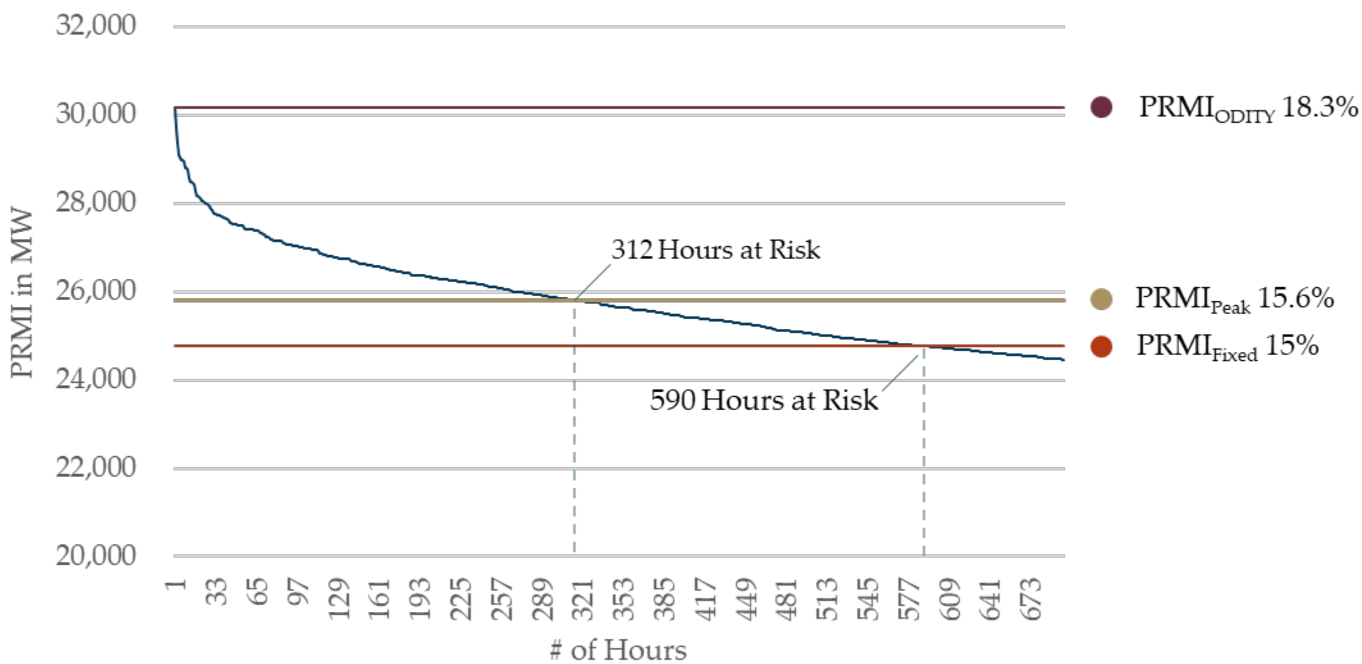

Figure 17: Western Interconnection PRMI Comparison 2023

A [subregional look](#) at the PRMI provides additional detail (Figure 18). In every subregion, there is a gap between the PRMI$_{\text{ODITY}}$ and the PRMI$_{\text{Peak}}$, though the size of the gap varies.

The CAMX subregion shows the smallest gap between its PRMI$_{\text{ODITY}}$ and PRMI$_{\text{Peak}}$, which likely reflects the change to the PRM requirement changes in the state in 2021.

The gaps between the PRMI$_{\text{ODITY}}$ and PRMI$_{\text{Peak}}$ in the other subregions are large. This reflects the assertion that the peak hour is not the hour in which the system is most strained because higher reserves are required to cover the variability on many other hours. So, entities that set their PRMs based on their annual peak demand may be short on other hours of the year. The same is true, though to a lesser degree, if entities use a fixed 15% PRM in their resource planning. If each subregion were to plan to a fixed or just the peak demand hour PRM, all subregions have demand-at-risk hours.

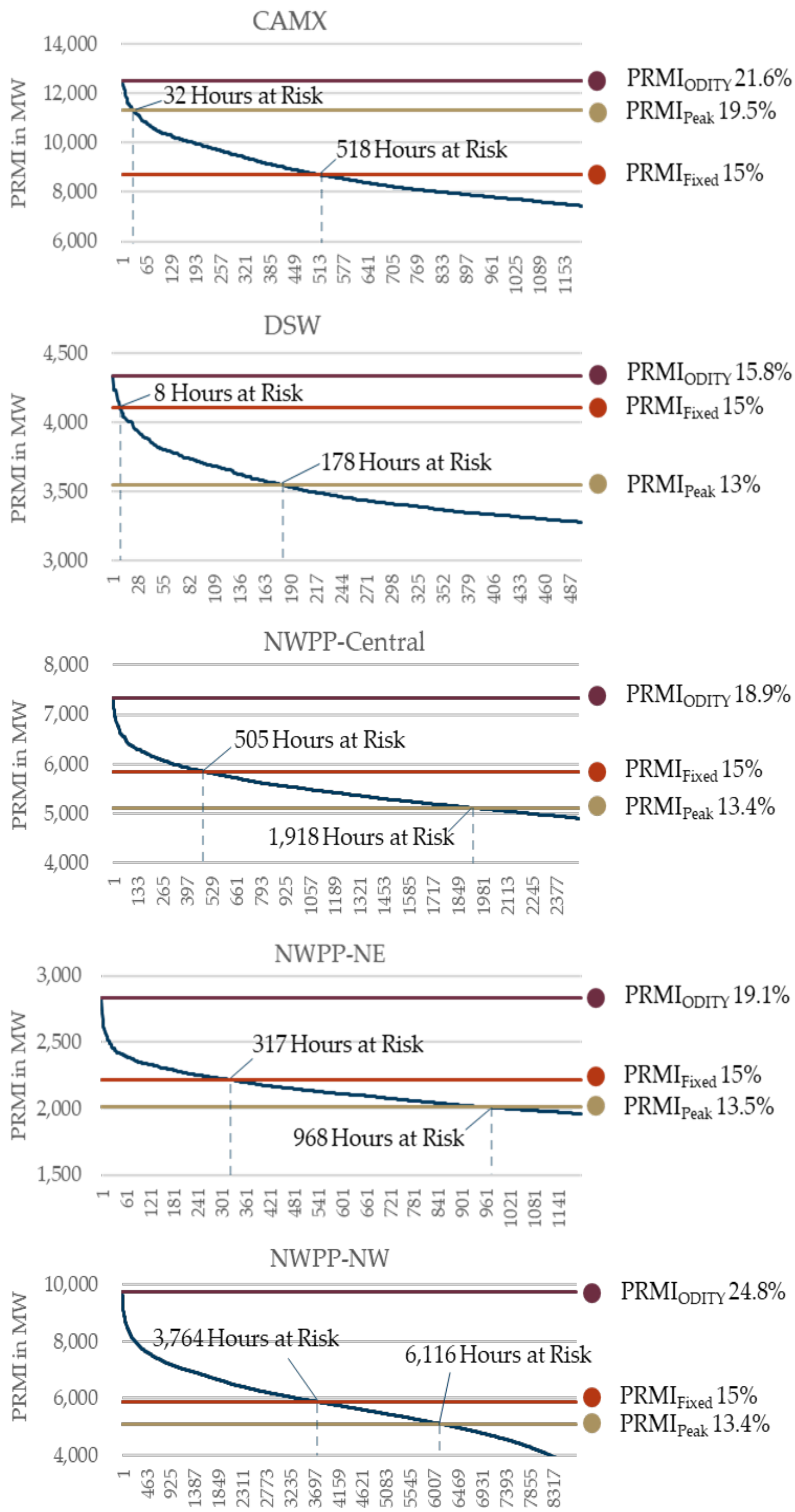

Figure 18: Subregional PRMI Comparison 2023

Resource Adequacy Risk

The PRMI duration curves provide information on the total number of demand-at-risk hours each year (frequency) given certain PRMI levels. The curves do not show the magnitude or timing of those hours. This section provides information on the magnitude (in megawatts) and time during the year demand-at-risk hours based on the $PRMI_{Fixed}$ and $PRMI_{Peak}$ for 2023.

$PRMI_{Fixed}$ Interconnection Findings

As a whole, the interconnection's highest risk occurs from spring to mid-fall. This is consistent with the fact that the interconnection is summer peaking and that the spring and fall shoulder seasons are times of high variability. The extreme events over the last three years have fallen into this period of time.

Compared to last year's Western Assessment, the number of hours at risk under the $PRMI_{Fixed}$ has increased substantially in magnitude and number (Figure 19). In addition, there are more hours at risk during the winter than in the 2021 assessment. This indicates that the risk to the system is growing and spreading across more of the year (Figure 20).

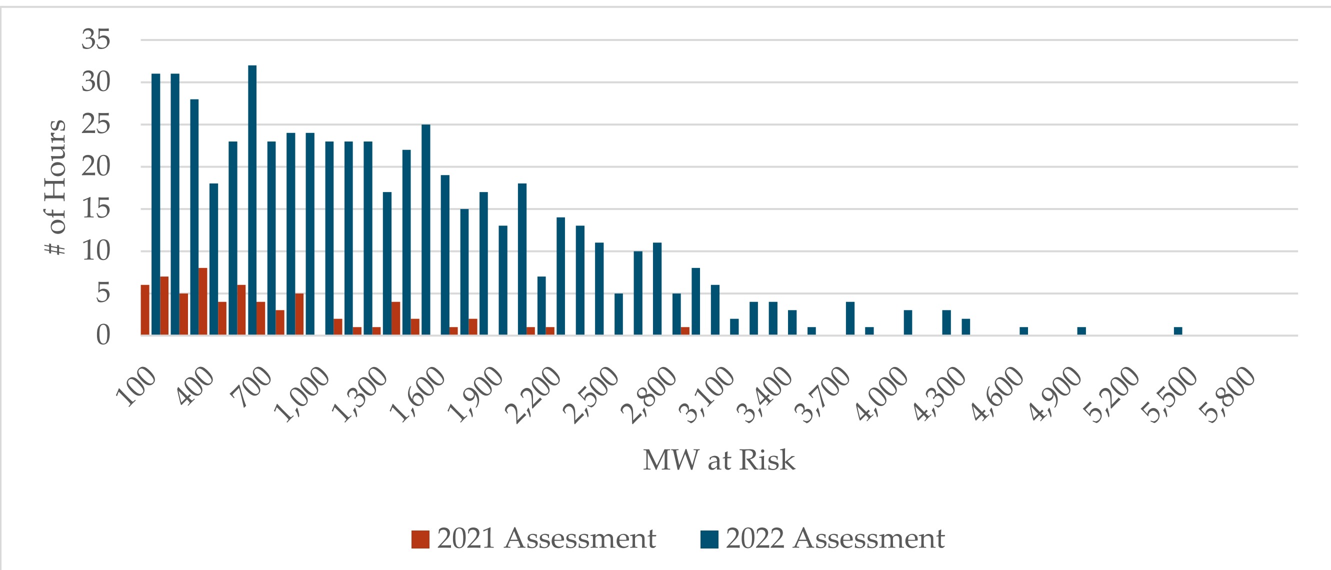

Figure 19: Comparison of Western Interconnection Demand-at-Risk Hours Frequency and Magnitude for 2023

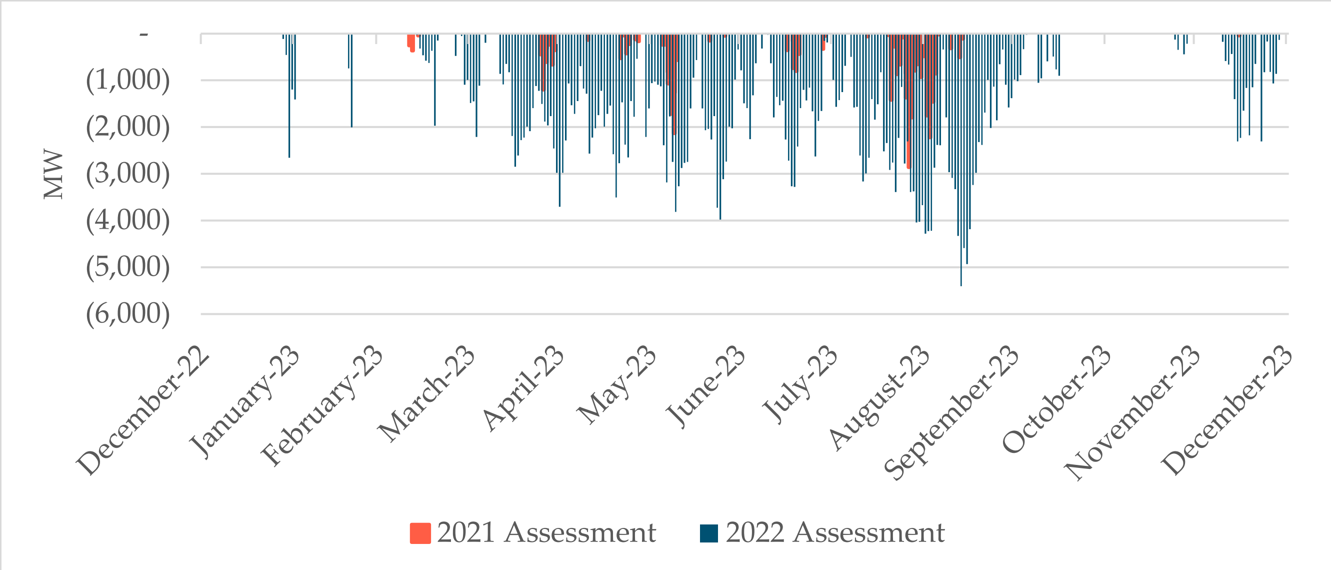

Figure 20: Comparison of Western Interconnection Demand-at-Risk Hours Magnitude and Timing for 2023

$PRMI_{Fixed}$ Subregional Findings

With the $PRMI_{Fixed}$, in 2023 each subregion fails to sufficiently account for its variability to varying degrees. This section provides a comparison of the 2023 demand-at-risk hour timing, magnitude, and frequency as determined in the 2021 and 2022 Western Assessments. This information illustrates how resources adequacy risk has grown over the last year.

CAMX

The CAMX subregion has the highest magnitude of demand at risk, peaking at over 3,500 MW on a single hour (Figure 21). The range of hours at risk extended slightly into mid-fall compared to the 2021 Western Assessment (Figure 22). In addition, while the most extreme magnitude did not change significantly from 2021 to 2022, in the 2022 assessment, there are more hours with greater magnitude risks than in the 2021 assessment. This suggests that the magnitude of the risk in the subregion has grown while the severity has not.

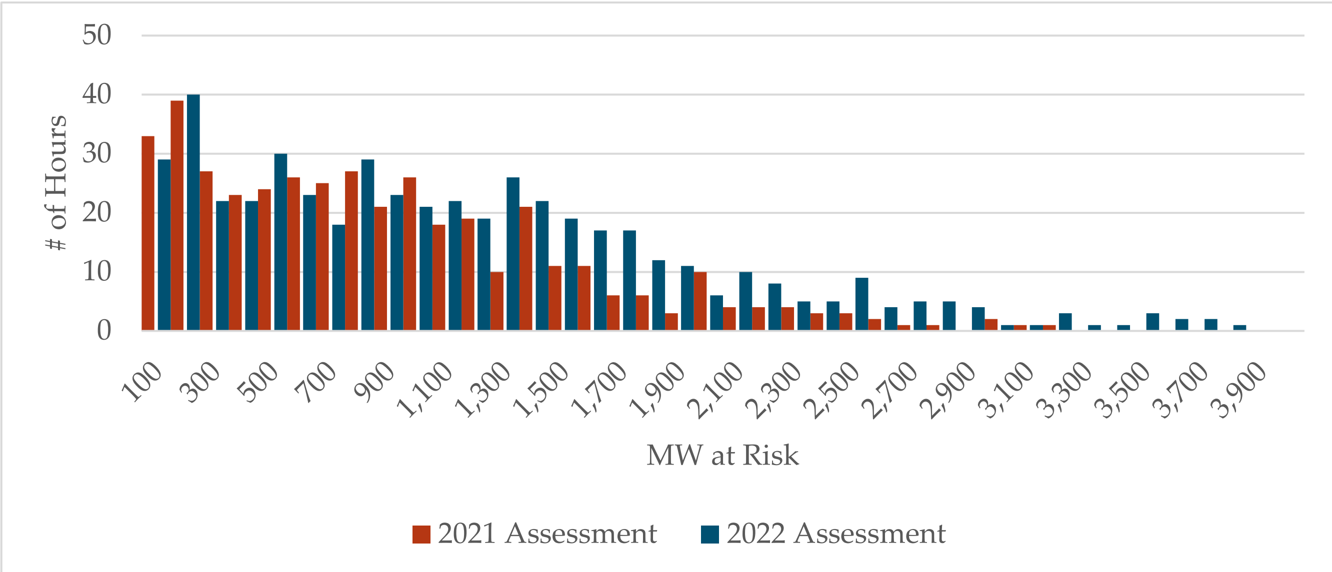

Figure 21: Comparison of CAMX Demand-at-Risk Hours Frequency and Magnitude for 2023

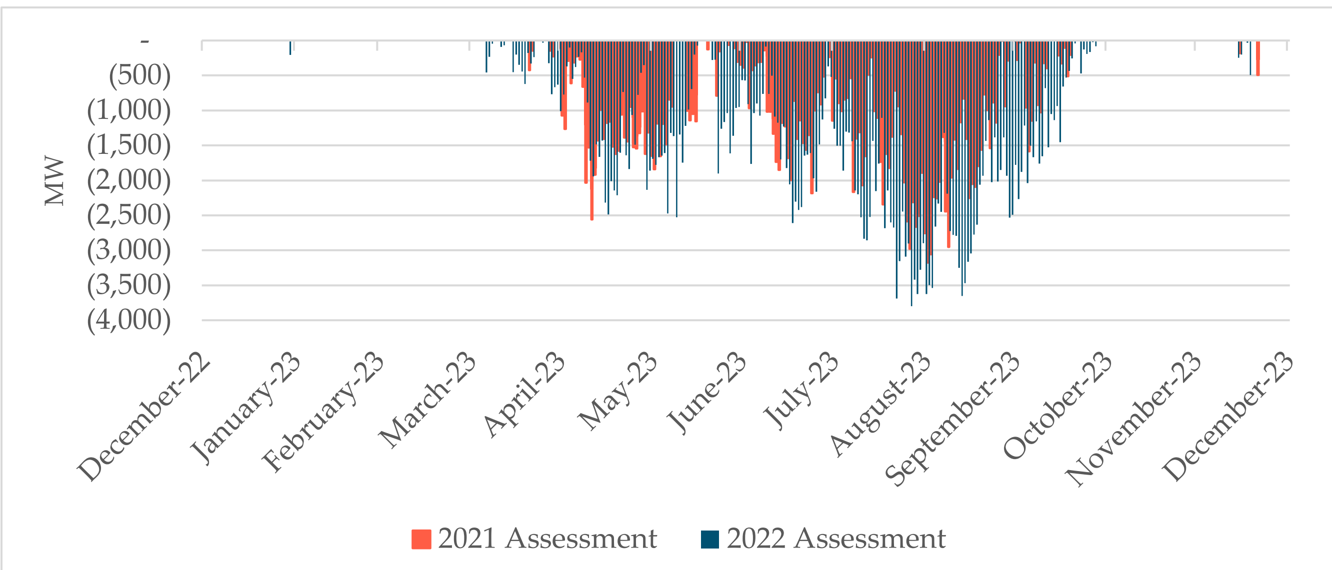

Figure 22: Comparison of CAMX Demand-at-Risk Hours Magnitude and Timing for 2023

DSW

The DSW subregion continues to show a small number of demand-at-risk hours, and that number decreased since last year's assessment (Figure 23). This is largely due to the lower level of weather-induced load variability in the subregion. Weather is the largest driver of both load and resource variability and the climate of the Desert Southwest is relatively consistent over the year (Figure 24). However, the DSW subregion is expected to build more VERs over the next 10 years. This will cause the timing of the demand-at-risk hours to spread and the magnitude of the risk to grow.

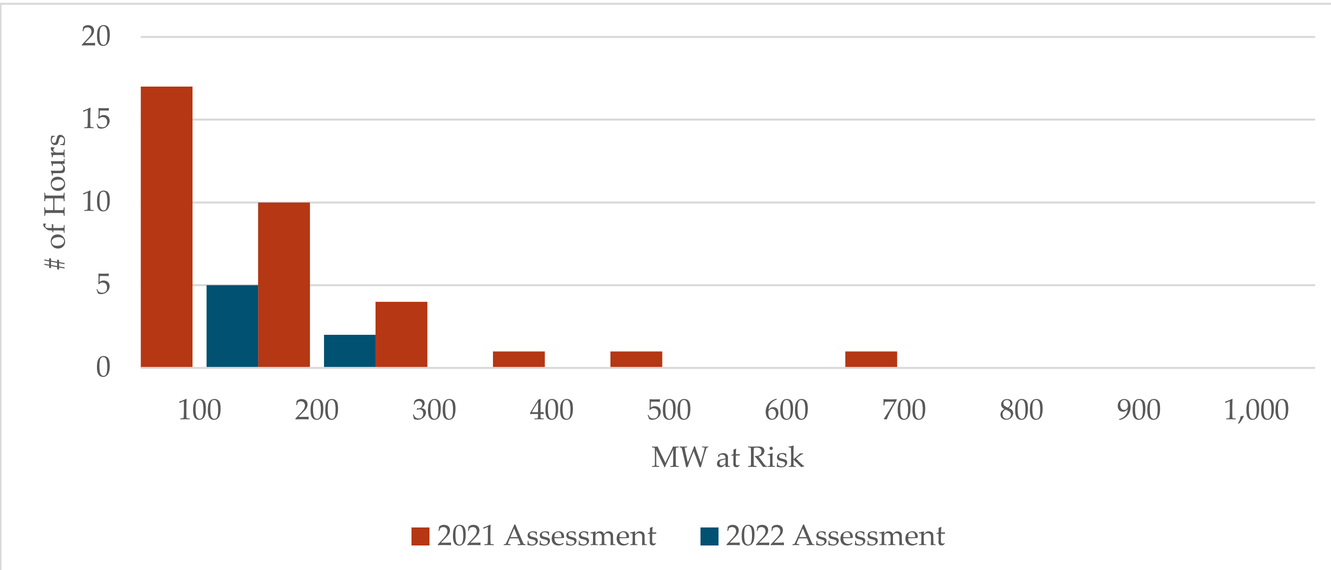

Figure 23: Comparison of DSW Demand-at-Risk Hours Frequency and Magnitude for 2023

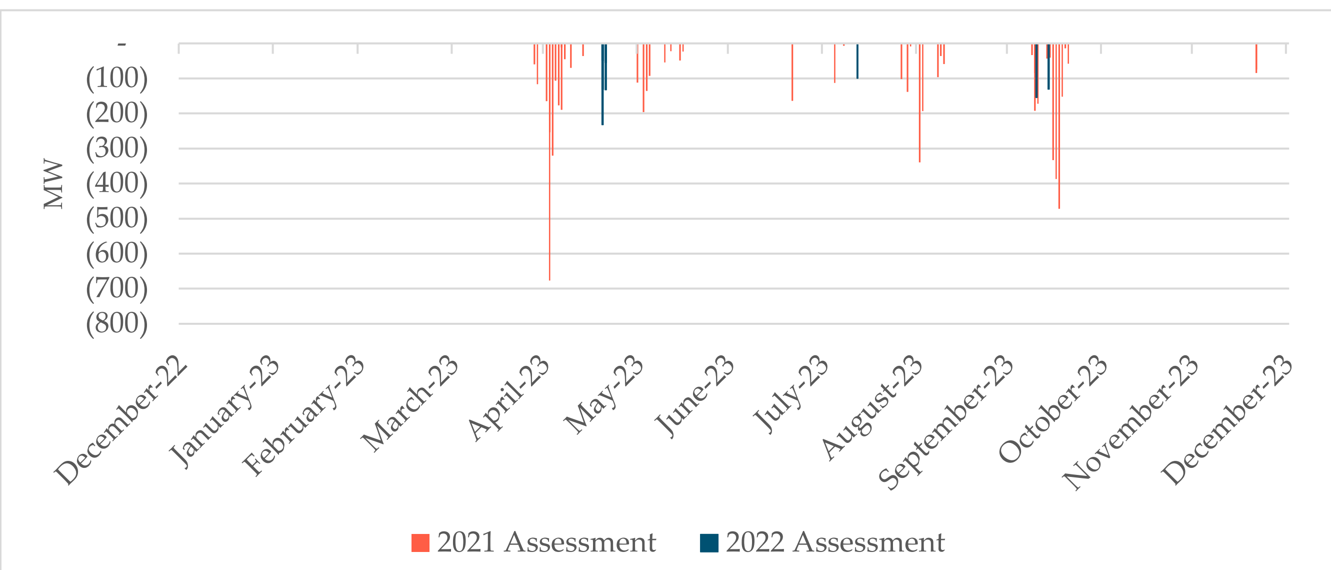

Figure 24: Comparison of DSW Demand-at-Risk Hours Magnitude and Timing for 2023

NWPP-Central

This year's results for the NWPP-Central subregion show a slight increase in both the number of demand-at-risk hours and the number of megawatts at risk (magnitude) compared to the 2021 assessment (Figure 25). As this subregion continues to add VERs and retire dispatchable resources, these numbers are expected to grow. The NWPP-Central subregion has the widest demand-at-risk spread, which covers almost the entire year (Figure 26). This is because its footprint straddles the northern (typically winter peaking) and southern (summer peaking) parts of the interconnection.

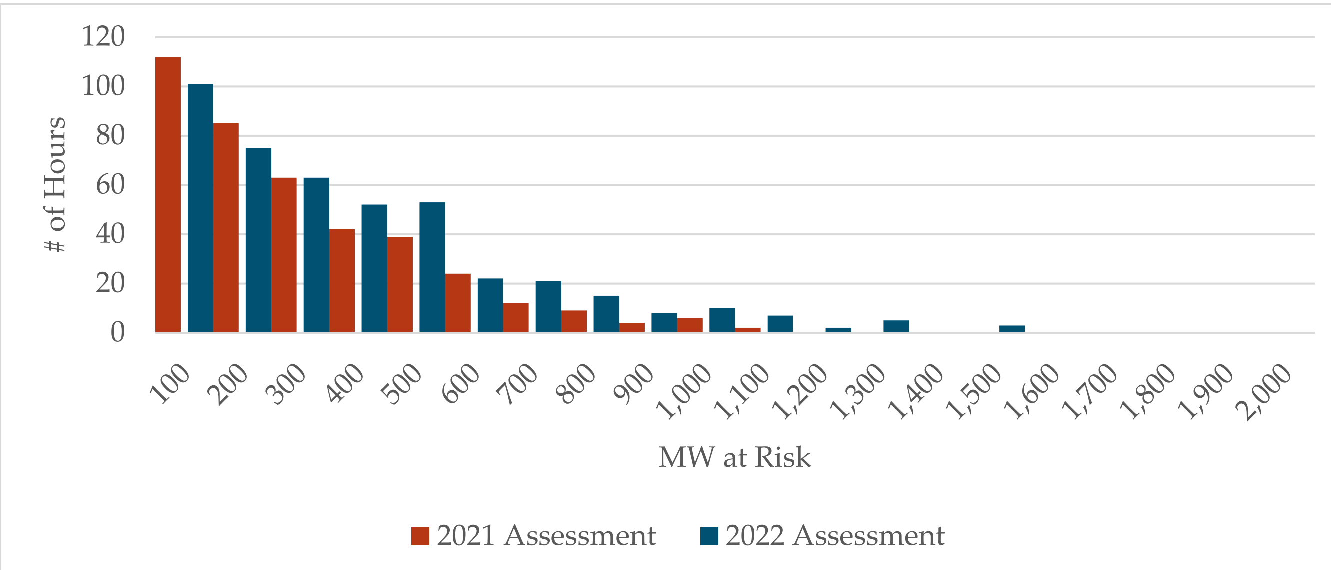

Figure 25: Comparison of NWPP-Central Demand-at-Risk Hours Frequency and Magnitude for 2023

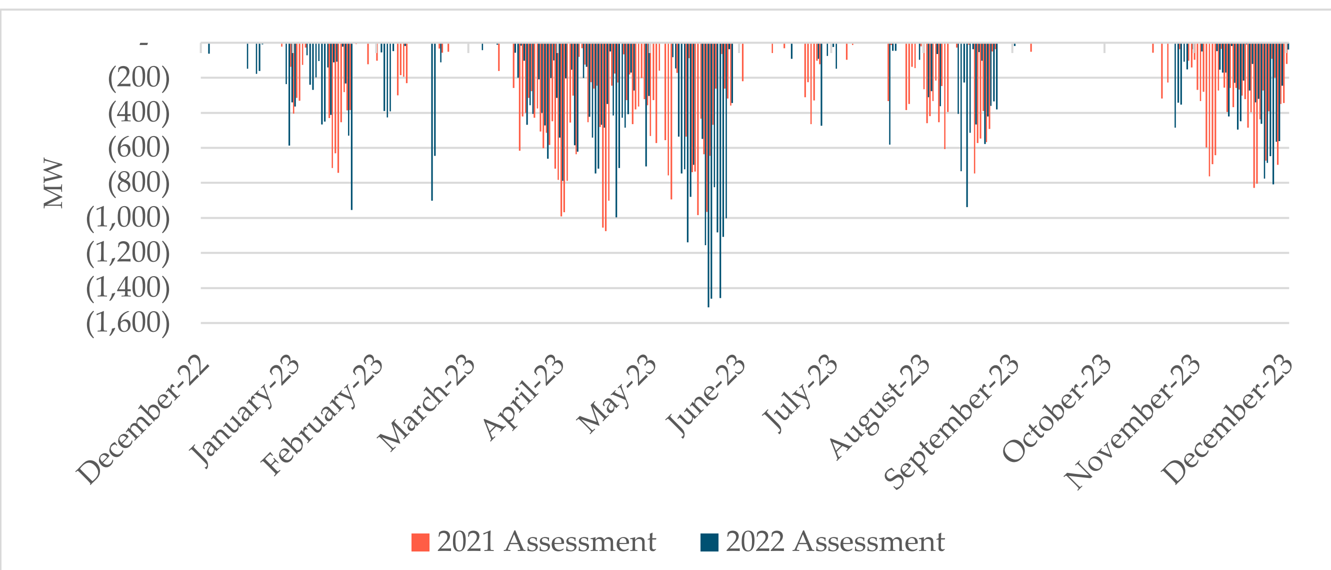

Figure 26: Comparison of NWPP-Central Demand-at-Risk Hours Magnitude and Timing for 2023

NWPP-NE

For the NWPP-NE subregion, the demand-at-risk hours were confined to December and January in the 2021 assessment, attributable to the variability in temperature during those months and the effects of heating requirements (Figure 27 and Figure 28). This year's results show that the risk has spread into February and March. This can be attributed to the changing resource mix. With the continued addition of wind resources and the retirement of coal resources, resource variability is expected to grow.

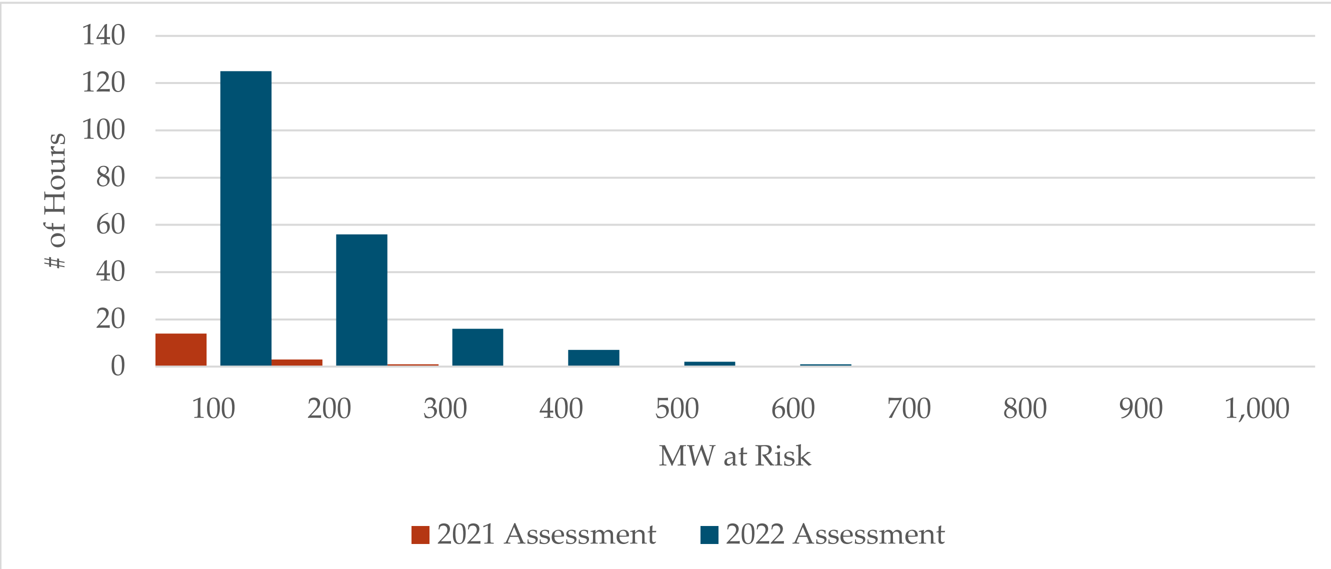

Figure 27: Comparison of NWPP-NE Demand-at-Risk Hours Frequency and Magnitude for 2023

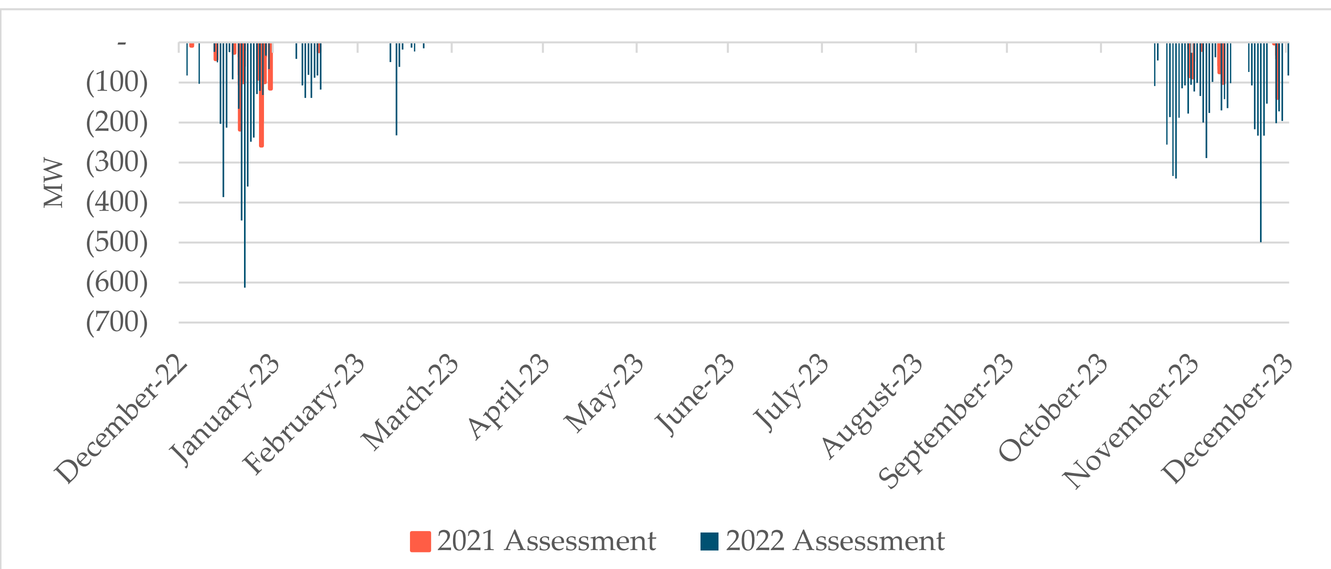

Figure 28: Comparison of NWPP-NE Demand-at-Risk Hours Magnitude and Timing for 2023

NWPP-NW

For the NWPP-NW subregion the risk has spread into the late spring and summer months (Figure 29 and Figure 30). This is due in part to the inclusion of data from the June 2021 Pacific Northwest heat wave in the 2022 assessment, increased the variability in the demand forecast for the subregion. So, while demand forecasts for the subregion decreased, variability increased, creating a need for additional reserves, which increases the PRMI. As the NWPP-NW evolves from a dual-peaking subregion to a summer-peaking subregion, the risk will continue to spread throughout the year.

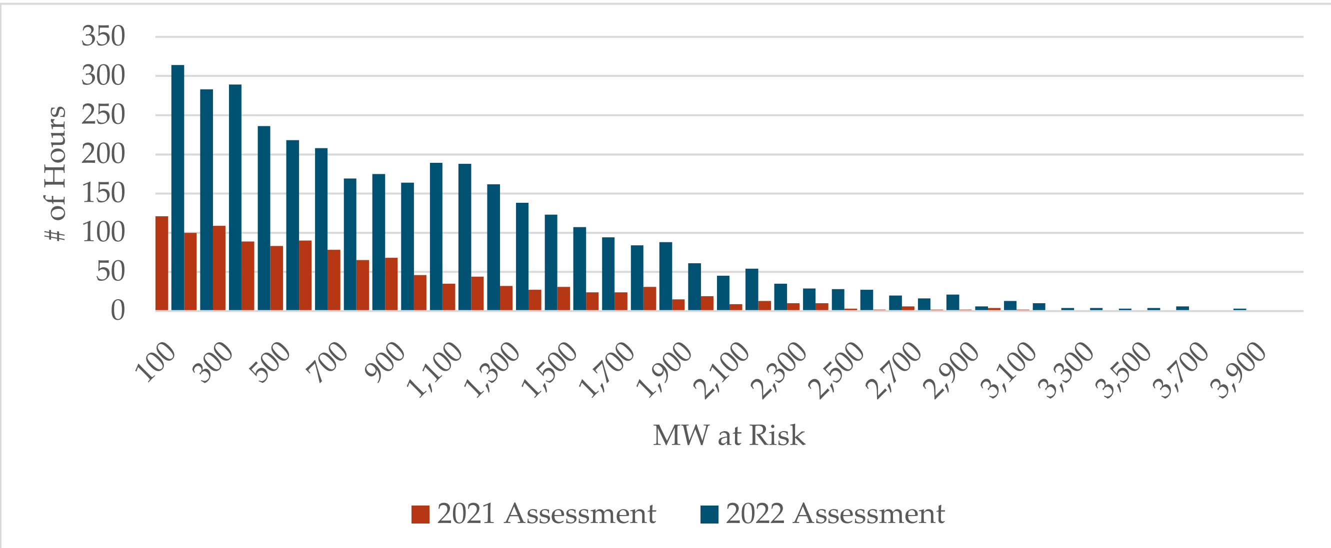

Figure 29: Comparison of NWPP-NW Demand-at-Risk Hours Frequency and Magnitude for 2023

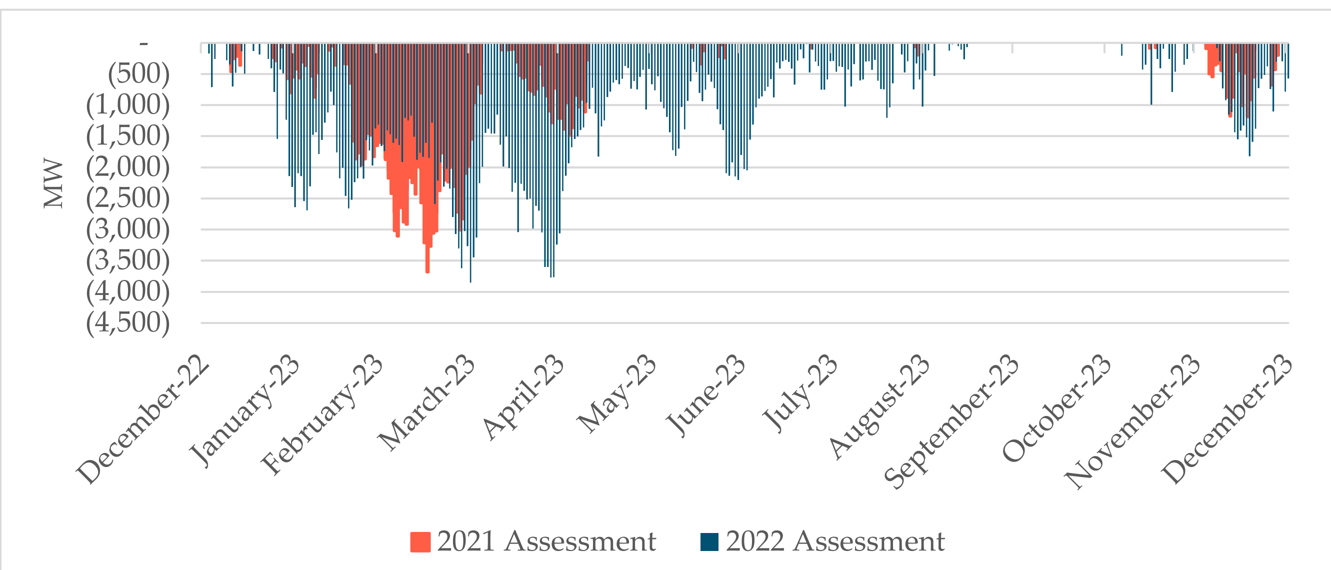

Figure 30: Comparison of NWPP-NW Demand-at-Risk Hours Magnitude and Timing for 2023

$\text{PRMI}_{\text{Peak}}$ Findings

While some resource planning entities are moving to an approach that accounts for variability across the entire year, there are still entities that determine their PRM based on the annual peak hour. Below is information on demand-at-risk hours when entities use this approach. In many cases, the $\text{PRMI}_{\text{Peak}}$ number is less than the $\text{PRMI}_{\text{Fixed}}$ because there is typically less variability during peak demand hours (it is usually very hot or very cold, with little change). This means that, if entities focus their resource planning on just covering the variability on the peak demand hour, they may not sufficiently account for variability in other hours and their demand-at-risk hours will increase compared to the $\text{PRMI}_{\text{Fixed}}$ (Figure 31). This is the case in all subregions except CAMX because the California ISO increased its PRM to account for variability, and its new PRM is greater than 15%.

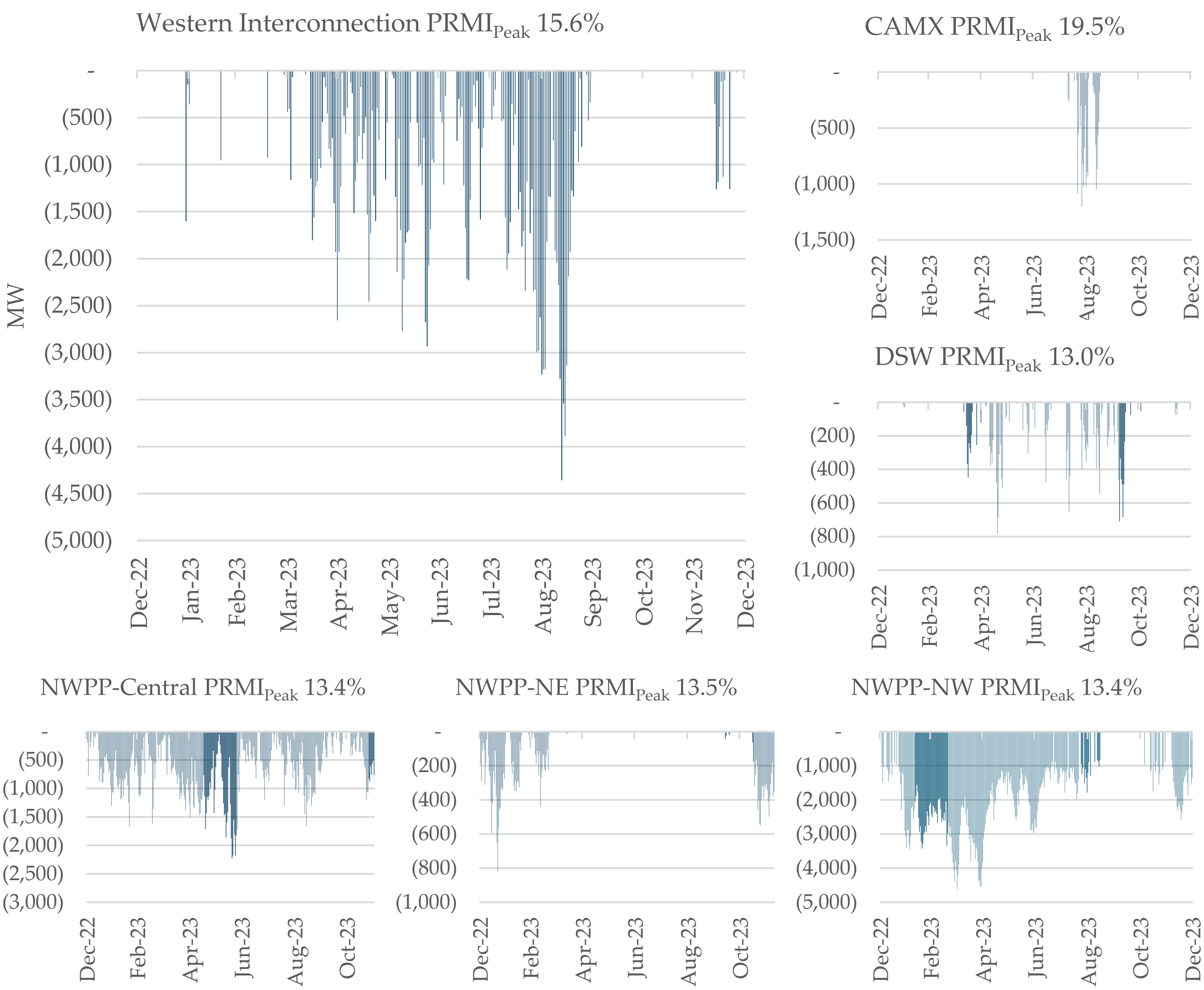

Figure 31: 2023 Demand-at-Risk Hours Magnitude (MW) and Timing Using the $\text{PRMI}_{\text{Peak}}$ for the Western Interconnection and Subregions

Resource Adequacy Risk Outlook and Recommendations

As the resource adequacy landscape in the Western Interconnection evolves over the next decade, there are several risks that need to be addressed to maintain reliability.

Near-Term Risks

Finding:

> Compared to the 2021 Western Assessment results, the DRI (number of hours at risk) decreased, suggesting that the risk for load loss decreased. However, the PRMI has increased, indicating that there is greater variability in the system, which needs to be accounted for to maintain reliability.

Compared to the 2021 assessment, the DRI for the Western Interconnection decreases through 2025 due in part to reductions in the load forecasts in the Pacific Northwest and northern Rocky Mountains, and, in part, to actions taken after the 2020 heat wave to strengthen resource adequacy. These actions include the addition of almost 3,000 MW of new or expedited resources, the vast majority of which is battery storage, and the delayed retirement of generator resources at plants such as Jim Bridger Powerplant, Haynes Generating Station, and Scattergood Generating Station. Once these plants are retired, the risk returns and will need to be mitigated. Delaying the retirements provides entities more time to determine how to mitigate the risks once these plants retire.

Long-Term Risks

Finding:

> Resource adequacy risks increase over the next decade. After 2025, each subregion shows an increase in DRI, due to retirements throughout the next decade. In addition, the PRMI continues to increase. This is primarily due to increasing variability from the addition of large amounts of VERs and increasing demand variability with record levels of peak demand.

The 2021 Western Assessment showed an interconnection-wide PRMI of 16.9% for 2023. The 2023 PRMI increased to 18.3% in the current assessment. Additional VERs, will cause the PRMI to increase further. If nothing is done to mitigate the long-term risks within the Western Interconnection, by 2025 we anticipate severe risks to the reliability and security of the interconnection.

Increasing Resource and Demand Variability

Variability creates resource adequacy risk on the power system. Over the next 10 years, demand and resource variability will increase, which means resource adequacy risks will increase. Based on current projections, by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%—one-day-in-10-year—reliability threshold. The PRMI for the Western Interconnection and all but the NWPP-NW subregion increases over the next 10 years. In addition, compared to the results in the 2021 Western Assessment, the frequency, magnitude, and range of hours where demand is at risk have all increased substantially. Not only is resource adequacy risk growing, but it is spreading across the year beyond the peak load seasons.

Finding:

The increase in the PRMI indicates that entities may need to plan for more reserves or take other actions to account for the increased variability. Mitigation actions could include:

- Adding dispatchable resources;
- Increasing demand management measures, e.g., energy efficiency;
- Participating in subregional cooperative efforts, e.g., market, resource adequacy program;
- Supporting the research and development of new technology; and
- Improving coordination of transmission planning and operation.

Impediments to Building Planned Resources

Planned resource additions of close to 80 GW in the next 10 years are comparable to the megawatts of resources added over the last decade. However, new challenges like supply chain disruption, skilled workforce shortages, and siting issues may impede or delay the build-out of new resources. Even with all planned resources built and imports available, all subregions show an increase in the DRI in the next 10 years. In years when large amounts of new resources are planned, the DRIs decrease, but delays or cancellation of these planned projects would most certainly result in additional demand-at-risk hours.

Considering that the results of this assessment indicate that the number of planned resources may not keep pace with the increases in variability over the next 10 years, any delays in building planned resources could pose a serious resource adequacy risk.

Recommendation—

Resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks. Likewise, commissions must be prepared to consider recovery of costs incurred by the utilities as they plan for increased risks.

Import Availability

The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint. However, an over reliance on imports can lead to resource shortfalls (in some cases due to lack of transmission capacity) during widespread events and extreme conditions, reflecting the experience during recent heat waves. This assessment examines the extent to which entity plans rely on imports to be resource adequate. Even with all planned resources built, imports cannot completely mitigate the risk created by increased system variability. Subregions show increasing DRIs over the next decade, which indicates heavy reliance on imports. During some hours, under certain circumstances, these imports may not be available, and any reduction in anticipated imports increases risk.

Recommendation—

The Western Interconnection should evaluate resource and transmission adequacy in a coordinated fashion through comprehensive wide-area system planning.

Heat waves have demonstrated that, under certain circumstances, the ability to move power can be as limiting as the availability of that power. Resource and transmission planning are inextricably linked and need to be considered together on an interconnection-wide basis.

Uncertainty

As drivers and reliability tools like electrification, batteries, microgrids, demand-side management, and new technologies continue to grow, their effect on the system is unclear. This makes load forecasting particularly difficult because load forecasters must figure out how to predict how these and other factors affect load. As the potential impacts of these factors are better understood entities will likely need to adjust their load forecasts, which has implications for resource planning. The effect this will have on resource adequacy risk is unknown.

Recommendation—

Some entities must evaluate and adapt their resource planning approaches to account for increasing uncertainty.

Traditional methods of resource planning and ensuring resource adequacy rely on predictability. Because historical information does not contain many of the elements that will cause increasing variability on the system in the future, it no longer provides a dependable foundation for predicting future system conditions. It is not clear that entities are taking these steps, as only a handful of entities in the West use robust planning methods to handle uncertainty and climate change in their resource planning processes.