WECC

2021 Western Assessment of Resource Adequacy

Navigating This Report

This report consists of five parts:

- **Chapter 1: Discussion of Resource Adequacy Approaches**
  Chapter 1 discusses current approaches to resource adequacy and outlines WECC's energy-based probabilistic approach used in this assessment.
- **Chapter 2: Probabilistic Analysis Findings**
  Chapter 2 provides the findings from WECC's energy-based probabilistic analysis, with emphasis on the changes in demand and resource variability expected in the next 10 years, increasing number of hours with potential load loss, and risks associated with reliance on imports to provide resource adequacy.
- **Chapter 3: Deterministic Analysis of System Condition Scenarios**
  Chapter 3 provides the findings from WECC's deterministic analysis of how the system behaves under extreme conditions, with emphasis on how different extreme scenarios affect a BA's ability to rely on imports.
- **Chapter 4: Supplemental Subregional Results**
  Chapter 4 provides results and findings from the probabilistic analysis for each of the subregions.
- **Appendices**
  Chapter 5 includes additional information to support the findings in the report, including a description of the methods and processes used, resource and transmission inputs, a guide to charts, a list of acronyms, and a glossary of terms.
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Executive Summary

The 2021 Western Assessment of Resource Adequacy (Western Assessment) concludes that resource adequacy risks to reliability are likely to increase over the next 10 years. WECC recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. Approaches to evaluating and planning for resource adequacy must adapt to changes affecting the system and evolve to ensure future reliability. The world has changed. The West has changed. These changes appear not only destined to continue, but to accelerate. If reliability and resilience are to be maintained, our planning, analyses, and ideas about resource adequacy must also change. Based on current projections, by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%—one-day-in-ten-year—reliability threshold.

Resource Adequacy Approaches

The West needs to change its approach to resource planning to avoid a deterioration of reliability over both the near-term (1–4 years) and long-term (5–10 years). Three changes must occur:

1. Calculate planning reserve margins (PRM) based on energy instead of capacity;
2. Use the most strained (variable) times on the system to determine the PRMs instead of relying on the assumption that if the peak is covered all other times will be covered too; and
3. Regularly recalibrate planning reserve margins when there are significant changes to resources or demand that may increase the variability on the system.

Typical approaches to evaluating resource adequacy are based on a comparison of expected peak demand and resource nameplate capacity. These capacity-based methods work when the resource performance and demand patterns are predictable and resource output is largely controllable. However, the capacity of a resource is how much power the resource can potentially produce and does not account for how much energy the resource can actually produce at any given time. Because resource variability has to do with changes in actual energy output, approaches based solely on capacity fail to fully account for variability. As a result, based on traditional capacity-based approaches, the West may appear resource adequate but could be resource inadequate in terms of its ability to produce energy when needed.

In addition, traditional approaches plan the system by focusing on the peak hour, based on the logic that planning the system to the time of greatest strain means the system will be resource adequate at all other times. While the logic is sound, the approach relies on the assumption that the system is most strained during the peak demand hour. Historically, this was usually the case. However, drivers like extreme weather, changing climate patterns, customer choice, and changing resource mix are resulting in situations in which the times of highest strain do not coincide with the peak demand. Resource planning that focuses solely on the peak hour ignores that the system experiences more strain and is at higher risk of being resource inadequate at other times.

Finally, traditional approaches typically set a PRM and held it at that level for long periods, in some cases many years. This approach works when the system remains relatively constant (e.g., demand patterns do not change, baseload resources are added). However, as demand becomes less predictable and variable energy resources (VER) are added to the system, an energy-based probabilistic approach to resource adequacy planning will help account for variability, and regular recalibration of the PRM will help ensure resource adequacy planning keeps up with the changing system.

Current State of Resource Adequacy

Using an energy-based probabilistic approach, WECC's analysis of resource adequacy over the next 10 years reveals the following takeaways:

- Both demand and resource availability variability are increasing, and the challenges they present appear worse now than they did in the 2020 Western Assessment.
- Under current PRMs, all subregions in the West show many hours at risk of load loss over the next 10 years.
- To mitigate resource adequacy risks over the near-term (1–4 years) and long-term (5–10 years), PRMs need to be increased—in some cases significantly—or other actions taken to reduce the probability that demand exceeds resource availability.
- Subregions rely heavily on imports to remain resource adequate. In no case can a subregion be resource adequate on its own.
- As early as 2025, all subregions will be unable to maintain 99.98% reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power.

Weather creates variability, and weather is growing more erratic and extreme—a pattern that is expected to continue over the next decade. Based on data reported by Balancing Authorities (BA), demand and resource variability have increased and will continue to increase over the next decade. In addition, predictions about more extreme weather and changing climate patterns portend increases in variability, likely beyond what entities currently predict.

Given these changes and current PRMs calculated using traditional methods, the number of hours at risk for load loss shows an increase compared to the results of the 2020 Western Assessment. This increase indicates resource adequacy planning may be failing to account for the increasing variability. Over the next 10 years, the hours at risk increase, even with planned resource additions.

Entities typically meet their PRM by building or purchasing resources within their area, contracting to import energy, or both. Changes in climate, weather, load patterns, resource location, and resource availability have altered how and when entities can rely on import capacity and the capability of the transmission system to move power. However, based on the increasing number of hours in which demand is at risk, entity resource adequacy planning practices largely have yet to account for this change. Entities who rely heavily on imported energy and do not change their resource planning practices to account for these changes could encounter resource adequacy challenges.

All subregions rely on imports to remain resource adequate today and in the future. If all Tier 1 and Tier 2 resources are built as currently planned, by 2025, even with imports, every subregion shows enough hours with demand at risk to fall below the one-day-in-ten-years, or 99.98%, reliability threshold—meaning every subregion could suffer a resource deficit. If current demand and resource projections hold or worsen, entities will have to take additional actions by 2025 to reduce the number or hours at risk for load loss. Because some solutions have long lead times, it is critical that entities act now to address long-term (years 5–10) resource adequacy concerns. If the current long-term issues are not addressed immediately, they may be insurmountable when they become near-term issues.

Scenario Analysis

To deepen the analysis of resource adequacy and provide an assessment of specific scenarios, this year the Western Assessment includes a deterministic scenario analysis in addition to the probabilistic analysis. The scenario analysis focuses on how different extreme scenarios affect a BA's ability to rely on imports. Because most entities rely to some extent on imports to be resource adequate, a change in energy available for import can greatly affect resource adequacy.

Three scenarios were analyzed to test the approach of combining probabilistic and deterministic techniques to better understand the near-term resource adequacy challenges given certain conditions on the system:

1. Expected Case—Expected demand and generation for the study year;
2. High Demand Case—1-in-33-year demand level (97th percentile); and
3. Drought Case—High demand and no generation from Glen Canyon Dam and Hoover Dam due to localized drought conditions.

The analysis showed dramatic changes in power flow across the interconnection in both the High Demand and Drought cases. In some instances, areas switched from exporting to importing power. With high demand, areas reduce exports to meet their own load. Without Hoover Dam and Glen Canyon Dam, nearly the entire southern part of the interconnection must rely heavily on imports. The greatest strain on the system in these scenarios occurs during off-peak hours.

The inclusion of scenario assessments using a deterministic zonal model is new to the 2021 Western Assessment. The cursory evaluation of the above scenarios provides valuable insight into the potential impacts that extreme events can have on power flows across the interconnection. The findings demonstrated that this kind of analysis can provide great value in evaluating resource adequacy, and more detailed analysis may provide important information on potential near-term risks.

Introduction

The Western Interconnection is undergoing extreme changes to demand and resource mix that require new approaches to how the system is planned and operated. The generation, load, and climate diversity in the West is shifting, variability is increasing, and both are occurring at an increasing pace. The changes are also widespread and require attention at an interconnection-wide level. This assessment evaluates existing resource adequacy approaches, proposes new methods, and assesses the resource adequacy of the system over the next 10 years.

Assessing Resource Adequacy

The Western Assessment is an analysis of resource adequacy across the entire Western Interconnection at an hourly level for the next 10 years. The assessment relies on data collected from BAs describing their demand and resource projections for that period. The Western Assessment evaluates resource adequacy across the entire interconnection and within five subregions (See Figure 1).

Figure 1: Western Assessment Subregions Map

The assessment uses two approaches to evaluate resource adequacy. The first is an energy-based probabilistic approach that evaluates potential demand and resource availability for each hour over the 10-year study period (2022–2031) to identify instances in which there is a risk of load loss. The second approach combines information from the probabilistic analysis with a deterministic model to examine how the system reacts to specific system conditions. The deterministic approach highlights risks associated with a few extreme scenarios.

Several conditions create the backdrop for this assessment, including a shift in the diversity of the interconnection, changes in demand and resource variability, the rapid pace of change, and the fact that resource adequacy must be analyzed and addressed across multiple time frames.

Diversity is Shifting

The diversity of generation type, peak load seasons, and climate zones that has been a cornerstone of the Western Interconnection's design and function is shifting. The interconnection is built on an ability to move power across great distances to take advantage of this diversity. Entities take advantage of this diversity by relying on imports in addition to their own resources to ensure demand is met. However, more frequent extreme weather and a changing climate are shifting this diversity, causing concern that imports may not be available when needed. For example, planners and operators can no longer assume that more temperate areas like the Pacific Northwest will be able to provide power to hotter areas like California and the Desert Southwest at any given time. In this assessment, WECC looks at imports across boundaries to determine how reliant subregions are on imports and whether those imports will be available given current projections.

Variability is Increasing

The West is in the midst of immense resource and load changes as it responds to extreme events, clean energy policies, customer choice patterns, and other drivers. The resource mix is becoming more sensitive to weather conditions as increasing amounts of variable energy resources are added and less-variable resources are retired. In addition, demand variability is increasing as once rare events occur with more frequency. Traditional methods of resource adequacy planning rely on the predictability of the system and do not fully account for the increasing amount of variability. This assessment evaluates traditional methods of analyzing resource adequacy and how those methods address variability. Specifically, practices like planning the peak hour and using capacity instead of energy may not fully capture variability's effect on resource adequacy.

Change is Occurring at an Increasing Pace

Long-standing planning practices have always relied on historical information about loads, weather, and generation to extrapolate future system behavior, but this information no longer provides a dependable foundation for predicting system conditions and future challenges. Rules of thumb used to target expected reliability and resilience outcomes of the bulk power system are falling short due to the immense change on the system. This assessment examines possible changes on the system through a probabilistic analysis. This analysis looks at a range of future conditions in addition to the expected future conditions provided by BAs.

Time Frames

Resource adequacy spans many time frames, from long-term planning (5–10 or more years) to near-term or operational planning (1–4 years), to the real-time operations horizon. Resource planning activities typically cover the long-term time frame largely due to the lead times needed to plan and build new resources. However, the reliability impacts of resource planning decisions occur much closer to real time. To address the different risks and possible mitigation activities associated with each time frame, this report combines a long-term probabilistic look at the next 10 years with a near-term deterministic evaluation of specific conditions in 2022.

Chapter 1

Discussion of Resource Adequacy Approaches

Resource Adequacy

The Western Interconnection is changing. To maintain reliability in the West, our planning, analyses, and ideas about resource adequacy must also change. The West needs to alter its approach to resource adequacy planning to avoid a deterioration of reliability over both the near-term (one to four years) and long-term (five to ten years). Planning entities in the West need to change their approach to resource adequacy planning in three ways. They should:

1. Calculate Planning Reserve Margins (PRM) based on energy instead of capacity;
2. Use the most strained times on the system to determine PRMs instead of relying on the assumption that as long as the peak is covered all other times will be covered too; and
3. Regularly recalibrate PRMs when there are significant changes to resources or demand that may impact the variability on the system.

Current Approach: Using Capacity to Calculate PRMs

Current approaches to calculating PRMs are typically based on resource capacity: a comparison of expected demand (in megawatts) to nameplate capacity (in megawatts). There are many ways to adjust these numbers, e.g., discounting nameplate capacity using capacity value to more accurately reflect the capacity that can be relied on from a given resource. However, regardless of how the numbers are altered, the calculation is based on capacity.

A resource-capacity-based approach starts with expected peak demand and then applies a reference margin using various assumptions to create buffers for reliability to ensure the peak hour is resource adequate (See Figure 1). Then the PRM is calculated based on the current portfolio. If the PRM is greater than the reference margin for a given hour, that hour is considered "resource adequate."

This method has worked in the past because resource portfolios were predictable and consistently ran relatively close to nameplate capacity. They consisted of hydro and various baseload resources like coal, nuclear, and natural gas. The output of baseload resources is controllable and fairly constant. Hydro resources can be variable, but years of data and operational

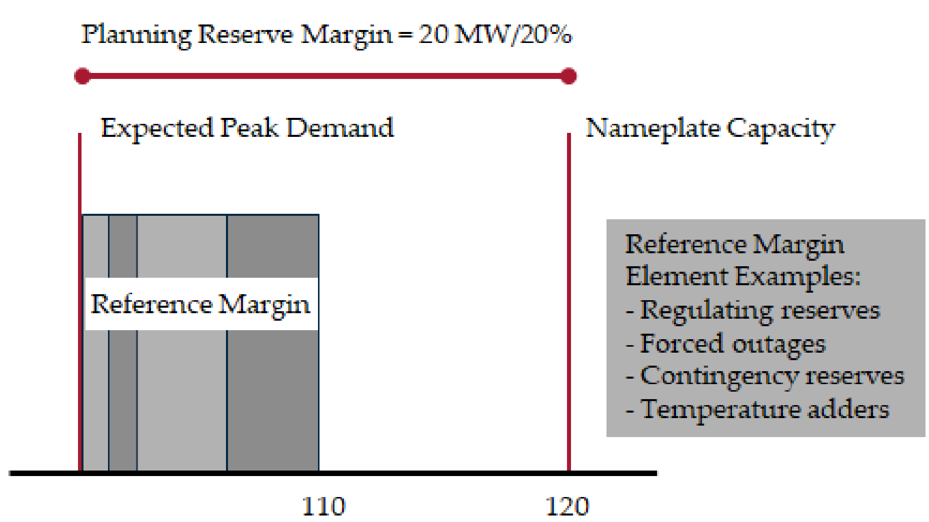


Figure 1: Planning Reserve Margin with a Capacity-Based Approach

experience have increased the ability to forecast them. Under traditional portfolios, the greatest source of variability was unforeseen or forced outages, which were adequately covered by the reference margin.

When variable energy resources (VER) like solar and wind were first added to resource portfolios, there were so few of them that their variability had little to no effect on the resource adequacy of the system. In other words, when a VER did not produce as expected, due to a change in weather, for example, there was enough headroom on the system to cover the missing energy from the VER. As VER penetration slowly grew, planners started accounting for the variability of VERs by discounting the nameplate capacity using methods such as capacity values (See Figure 2). This approach allowed planners to continue calculating PRMs using capacity while accounting for the low level of variability in energy output from VERs.

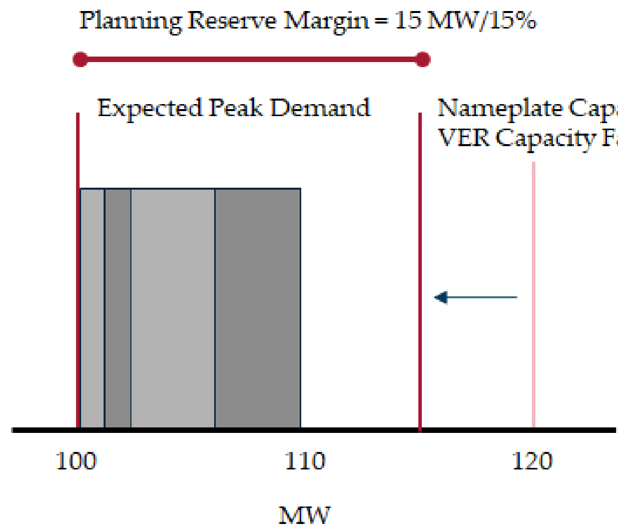


Figure 2: Capacity-Based Approach with Capacity Factors

As the resource mix has further changed, baseload resources like coal and nuclear have been retired and VERs have increased. This has increased the overall variability of the aggregate resource mix. Before the addition of large amounts of VERs, the probability curve for the energy output of the resource mix was fairly narrow; meaning actual output would not vary greatly from the expected or forecast output (See Figure 3). The reference margin was established to cover the probability of forced outages (among other things). Therefore, if the energy output varied due to forced or unplanned outage, the reference margin would cover it. However, as VERs are added and variability increases, the energy output probability curve expands. Once

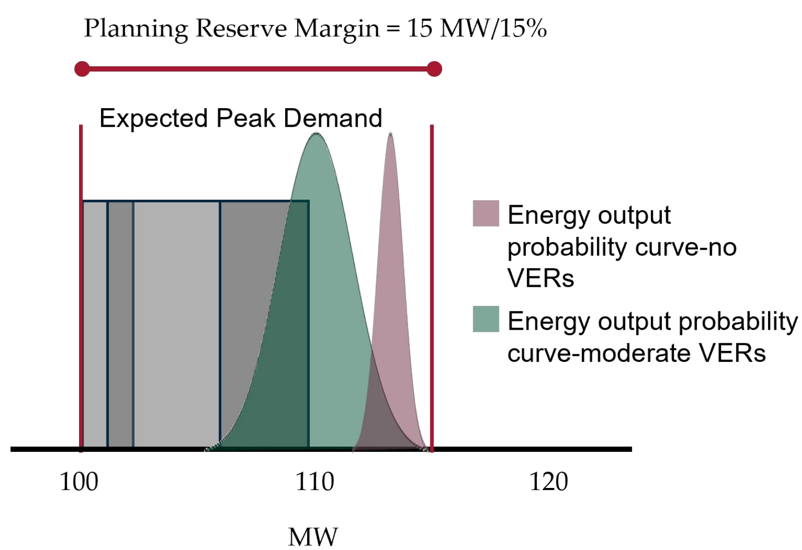


Figure 3: Capacity-Based Approach with Probability Curves

enough VERs are added, the curve expands far enough that the energy output of the resource portfolio may fall short. This could result in the reference margin not alleviating the variability, making the system "resource inadequate." The resulting situation is a system considered resource adequate in terms of capacity, but resource inadequate in terms of actual energy produced. In practical terms, this means, once the amount of VERs on a system reaches a certain level, the system could be viewed as having *adequate capacity* to serve demand—even under extreme conditions—but the system may not be able to *produce enough energy* during an extreme event.

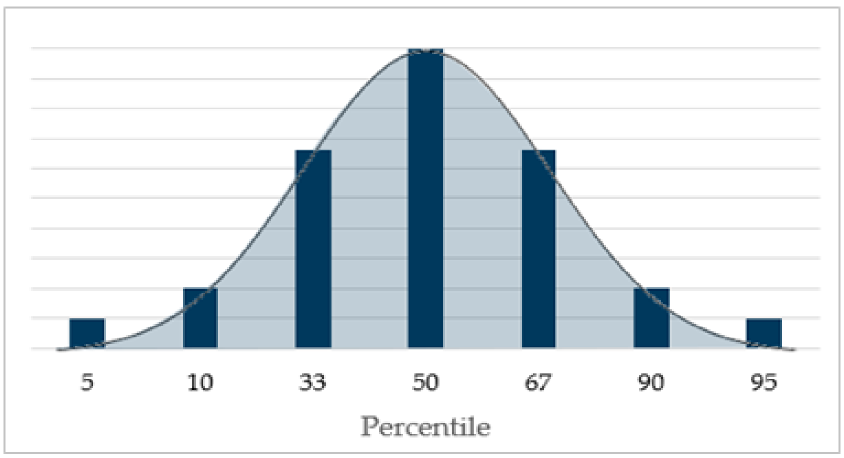
In addition to increased system variability, demand variability has also increased due to drivers like customer choice, climate change, and extreme weather. This combination of increased generation and demand variability requires the West to evaluate resource adequacy in terms of energy availability, instead of viewing resource adequacy solely in terms of capacity. This will allow planners to understand where and when potential energy shortfalls might occur. If this change is not made, the West can expect future resource shortfalls like it experienced during the August 2020 Heat Wave Event, in which load was shed.

A New Approach: Energy-Based Probabilistic Analysis

To evaluate and account for increasing variability, WECC recommends entities use an energy-based probabilistic approach and regular recalibration of the PRM.

Energy-Based Probabilistic Analysis

An energy-based probabilistic analysis—like the analysis used in this assessment—looks at the probability that demand and resource availability will occur at the expected energy value. This can be plotted on a probability curve (See Figure 4). The curve shows the probability of potential levels of demand or resource availability based on the expected value WECC receives from Balancing Authorities. For example, the expected number provided by Balancing Authorities represents the 1-in-2 (also 50/50, 50%, or 50th percentile) probability. Examples of the other common probabilities referenced in this report can be found in the table.



Probability	Percentile	Likelihood of Occurrence
1-in-20	5th	5%
1-in-10	10th	10%
1-in-3	33rd	33%
1-in-2	50th	50% (expected)
1-in-3	67th	33%
1-in-10	90th	10%
1-in-20	95th	5%

Figure 4: Example Probability Curve and Table of Common Probabilities

The probabilistic analysis used in this report evaluates the probability curves of demand and resource availability together (See Figure 5). The area in which these curves overlap represents the possibility that there will not be enough resources available to serve the demand. This is called demand at risk. The overlap is the only place where the resource availability number could be less than the demand number. The greater the overlap of the two curves, the greater the likelihood that this will be the case. Consequently, the goal is to keep the two curves far enough apart so the overlap—or probability that demand will exceed resource availability—is kept below a certain threshold. This threshold is determined by the planning entity's risk tolerance. For this analysis, WECC has set the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning 99.98% of the demand for each hour is covered by available resources; i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour.

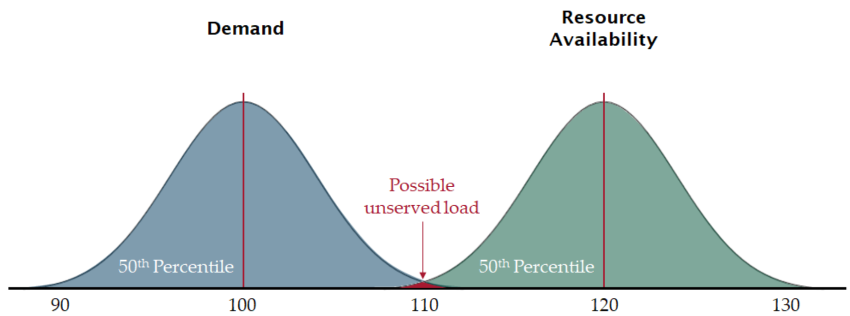


Figure 5: Example Demand and Resource Availability Curves

The overlap—the demand at risk—can increase when one or both of the curves move. This happens when the expected demand increases or the expected resource availability decreases, or both. In any of these cases, the curves maintain their original shape but move closer together, increasing the overlap (See Figure 6). An example of this occurrence is when a Balancing Authority updates the expected demand forecast to a higher level without changing the portfolio.

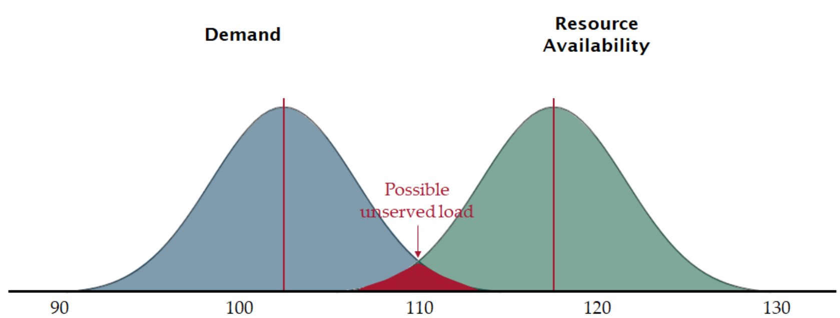


Figure 6: Demand and Resource Availability Curves with Increased Overlap

Another way that the overlap is increased is through variability. When rare events occur more regularly than predicted, the probability curve changes shape. For example, heat wave events like those that occurred in the West in 2020 and 2021 were once rare events. The August 2020 Heat Wave was a 1-in-30 event, but when evaluated considering climate change, this type of event now becomes more likely, with a 1-in-20 chance of occurring. Roughly two weeks after the August heat wave, there was another extreme heat event that had a 1-in-70 chance of occurrence, which, after accounting for climate change, has a 1-in-40 chance of occurring again. The June 2021 Heat Wave in the Pacific Northwest was a 1-in-1000-year event, which, when calculated to account for climate change, is now 150 times more likely to occur again. As these extreme events become more common, the probability that they will occur increases. When a rare event like a 1-in-30 event becomes more common, the probability curve around it changes shape (See Figure 7). When one or both of the curves change shape, and nothing else changes, the overlap of the two curves can increase, boosting the likelihood that demand will exceed resource availability (See Figure 8).

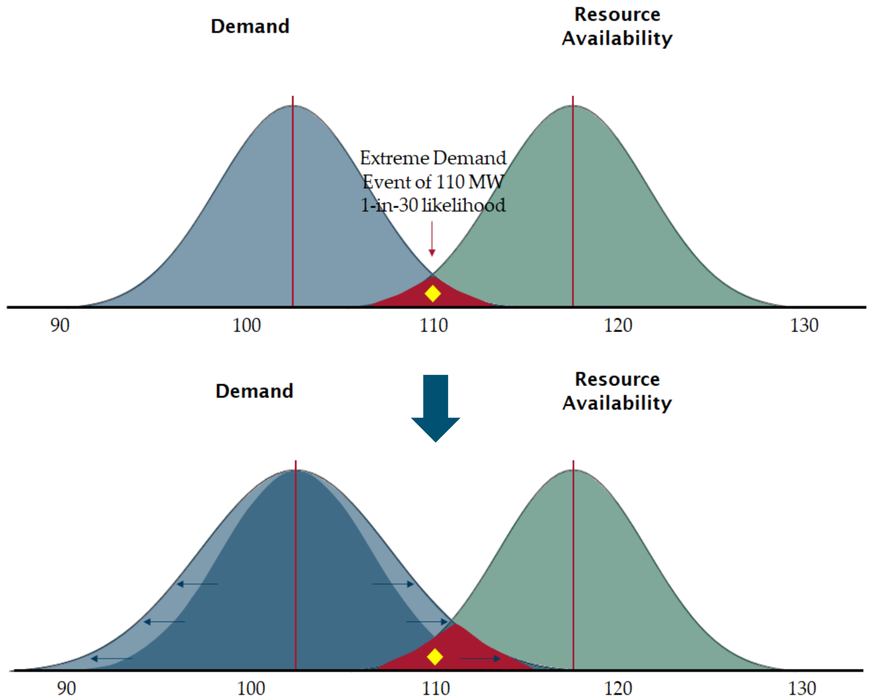


Figure 7: Demand and Resource Availability Curves with Expanded Demand Curve

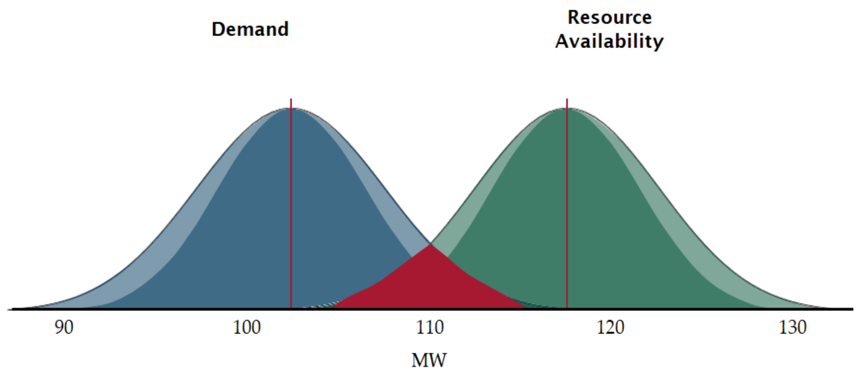


Figure 8: Demand and Resource Availability Curves Expanded Due to Variability

Calculating the Planning Reserve Margin

This assessment generates PRMs that produce an overlap in demand and resource availability probabilities that represent no more than a .02% chance that demand will exceed available resources—making the grid 99.98% resource adequate. In Figure 9, with an expected 1-in-2 chance that demand is 100 MW and resource availability is 120 MW, a 20-MW—or 20%—planning reserve margin is needed to remain 99.98% resource adequate. This is based on the shapes of the demand and resource availability curves.

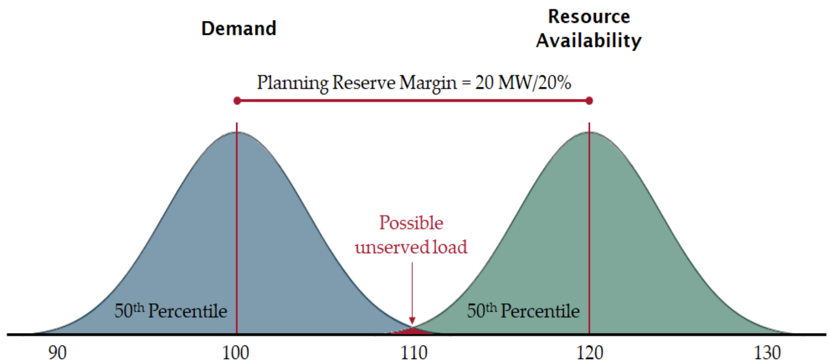


Figure 9: Example Demand and Resource Curves with 20% PRM

If a planning entity expects to have only 115 MW of resources available, the planning reserve margin shrinks to 15 MW, or 15% of expected demand (See Figure 10). This increases the likelihood that demand will exceed available resources. In this example, Figure 10 shows that the resource curve moved to the left by 5 MW, moving the curves closer together and increasing the overlap.

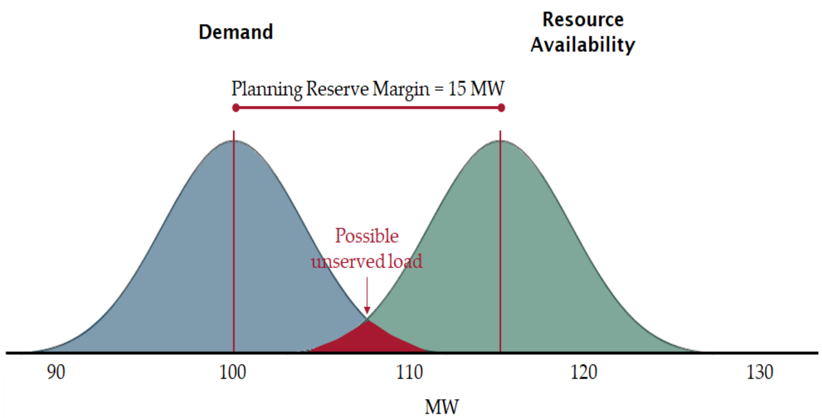


Figure 10: Example Demand and Resource Curves with 15% PRM

When demand and resource variability are added, shown by the expanding curves in Figure 11, the 15-MW PRM becomes even less effective. The expected demand has remained the same (100 MW), increasing the overlap. If the 15-MW PRM is used, the system is not 99.98% resource adequate.

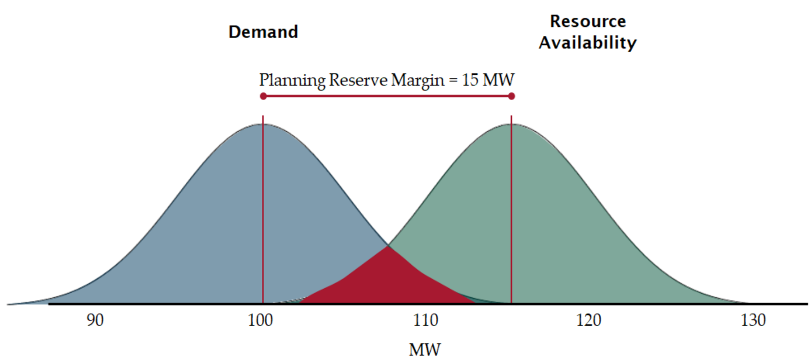


Figure 11: Expanded Demand and Resource Curves with Large Overlap

To return to 99.98% reliability, the PRM would need to increase to 22 MW (22%) to account for the changes in demand and resource availability (See Figure 12).

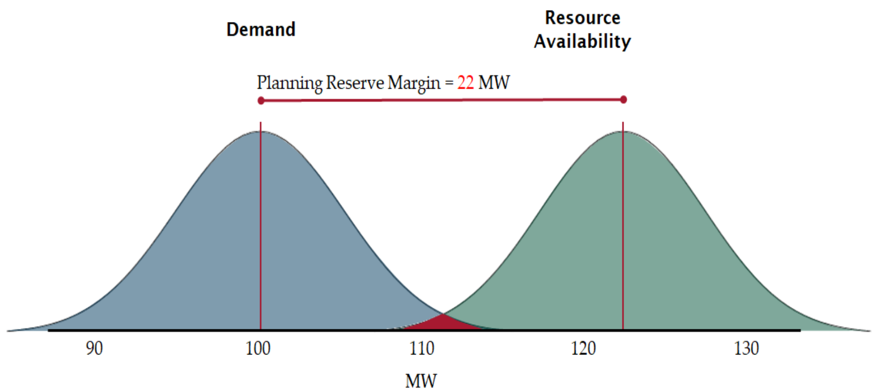


Figure 12: Example Demand and Resource Curves with 22% PRM

This example assumes that entities use the PRM to cover the increased variability, i.e., as variability increases, entities must increase their PRMs to remain 99.98% resource adequate. In reality, there are additional ways to separate and shrink the curves.

Planning to the System Peak

Historically, resource adequacy planning has focused on the annual peak demand hour. The traditional approach is based on the idea that, if the system is resource adequate when it is the most strained, it will be resource adequate at all other times. The system peak demand hour has been considered the time of greatest strain on the system. So, planners have based their PRM and other resource decisions on the peak demand hour; e.g., if an entity considers a 15% PRM during the peak hour to be resource adequate, it assumes that a 15% PRM will make it resource adequate during every other hour of that year. When the system had relatively consistent and predictable generating sources, this method was sufficient. However, drivers like extreme weather, changing climate patterns, and the shift toward VERs are increasing variability and uncertainty. During times of high uncertainty, the system may have to respond quickly to large changes in demand, resource availability, or both. This strains the system more than the peak demand hour because the system is less prepared to address variability than it is to address the peak demand. Entities make the vast majority of resources available to meet the peak demand; so, while demand is highest during the peak demand hour, the system is also best prepared to meet demand. During times of high uncertainty, which often fall in shoulder periods, the system may not be prepared to respond. This means the time of highest strain on the system has changed to times of high uncertainty, which do not coincide with the peak demand hour.

With the changes in the Western Interconnection, resource planning methods have started adapting to account for variability and uncertainty. In many cases, entities plan using probabilistic methods, but their analyses are still based on capacity. They run a probabilistic study on unplanned outages of baseload resources to determine whether they meet their reliability threshold (e.g., ODITY), and they use a capacity value for VER output. In addition, these analyses are still focused on the peak demand hour, which is not the hour of highest strain on the system. Resource adequacy should be analyzed using probabilistic processes that look at hourly results across a range of supply and demand scenarios including VERs. These scenarios should analyze the degree of variability in demand and resource availability.

Recalibrating the Planning Reserve Margin

To ensure the system maintains 99.98% reliability, the PRM needs to be recalculated any time there is a substantial change to demand, e.g., extreme weather events, or resource availability, e.g., new Integrated Resource Plan. So, rather than setting a PRM and leaving it, accounting for the changing conditions and variability on the system will require more frequent recalculation of PRMs. WECC refers to this as "PRM recalibration."

Figure 14 shows the need for a PRM recalibration. As VERs are added to the system, they add capacity and variability. In the example, adding 20 MW of VER increases the resource availability, shown by the curves moving further apart. However, the increased variability these resources create also shows as a change in the shape of the resource availability curve. This means that when VERs are added, the PRM needs to be recalibrated to ensure it still maintains the desired level of reliability. The same is true when once-rare demand events happen with more frequency and change the shape of the demand curve.

Note that VERs are not the only resources that are variable. Any resource on the system has a probability curve associated with it because any resource can experience an unplanned outage. However, the probability of variability associated with traditional resources (e.g., coal, natural gas, hydro, nuclear) relies less often on factors associated with fuel adequacy and does not have a large effect on the required PRM on a plant-by-plant basis. That said, single-point-of-failure events, like widespread fuel supply issues or extreme drought conditions affecting hydro generation, can change the variability of these resources. If these very rare events occur more frequently, the added variability will effectively change the shape of the resource availability curve.

Chapter 2

Probabilistic Analysis Findings

Probabilistic Analysis

This assessment of the state of resource adequacy uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances in which there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level and within each of the following subregions (See Figure 1):

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

Figure 1: Western Assessment Subregions

These groups align with the three reserve sharing groups in the interconnection—the California Independent System Operator (CAISO), the Southwest Reserve Sharing Group (SRSW), and the Northwest Power Pool (NWPP). The NWPP, has been divided into three subregions according to the timing of their peak.

This section provides results and findings from the interconnection-wide analysis and highlights from the subregional analyses. Chapter 4 contains more results and findings for each subregion.

Takeaways

WECC's analysis of resource adequacy over the next 10 years reveals the following takeaways:

- Both demand and resource availability variability are increasing, and the challenges they present appear worse now than they did in the 2020 Western Assessment of Resource Adequacy.
- Under current planning reserve margins (PRM), all subregions in the West show many hours at risk of load loss over the next 10 years.
- To mitigate resource adequacy risks over the near-term (1–4 years) and long-term (5–10 years), PRMs need to be increased—in some cases significantly—or other actions taken to reduce the probability that demand exceeds resource availability.

- As early as 2025, all subregions will be unable to maintain the one-day-in-ten-year (ODITY) resource adequacy threshold—99.98%—because they will not be able to eliminate the hours at risk for loss of load even if they build all planned resource additions and import power.
- Resource adequacy risks could get worse before they get better if action is not taken immediately to mitigate near-term risks and prevent long-term risks.

Increasing Variability

The variability of demand and resource availability in the Western Interconnection will continue to increase over the next decade. This makes system planning more challenging and the need for change urgent. Accounting for variability will require a change to a new way of planning, one in which the system is planned to its potential extremes, rather than expected conditions. Entities need to account for variability in resource adequacy planning in three ways:

- Adopt methods to examine hours of high variability, such as shoulder seasons;
- Adjust resource adequacy metrics to account for variability; and
- Fully consider the availability *and* variability characteristics of capacity additions.

Demand Variability

Extreme weather is a significant driver of demand variability. While other drivers like electrification and distributed generation will change demand patterns, weather has the greatest ability to change demand patterns in an unpredictable way. In addition, weather may change demand patterns more quickly and with much less notice than other drivers. Climate change and extreme weather events will continue to intensify, making future demand difficult to predict.

Historical Demand Variability

In recent years, variability has continued to increase. Figure 2 shows two versions of the variability distribution curve for one hour in 2022 for a summer-peaking area. The first version is calculated using historical data submitted to WECC for analysis between 2007 and 2013. The second version of the curve uses historical variability data submitted between 2014 and 2020. The demand numbers in the second curve (2014–2020 data) show a shift in the expected value and

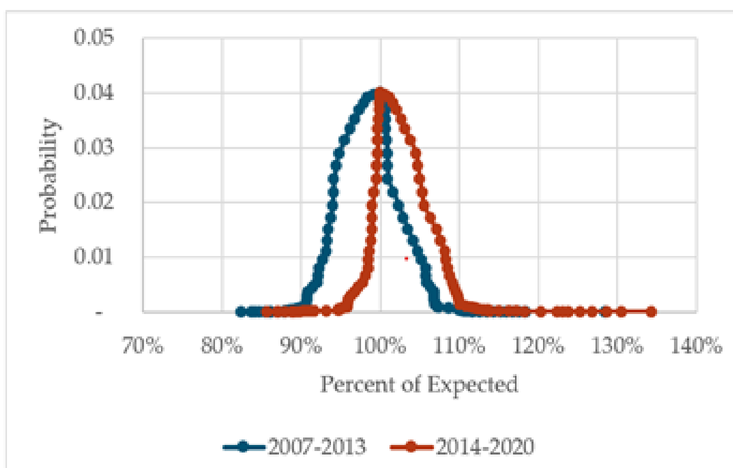


Figure 2: Comparison of Demand Variability Curves for 2022

overall increase of demand numbers at any probability. The second curve also shows an extension of the tail on the high side of the curve. This is due to the recent heat wave events and additional behind-the-meter-solar generation that has been added to the system. These curves illustrate the variability on the system has increased because we see more variability from recent projections for 2022 than from older projections for the same year.

Future Demand Variability

This year's analysis shows additional increases in overall demand variability compared to what was reported in the 2020 Western Assessment. The increase is because the 2021 analysis includes data from 2020, which includes the 2020 heat waves in August and September. This results in a change in the data in the form of an increase in variability because it reshapes the demand curve, especially in the shoulder seasons.

Based on the new data, in 2022, the Western Interconnection shows an expected peak demand of 164,650 MW. However, there is a 1-in-3 probability that the demand could increase to 170,065 MW (a 3% increase), and a 1-in-33 probability the peak demand could reach 189,597 MW (See Figure 3). This represents a change of more than 15% from expected demand levels.

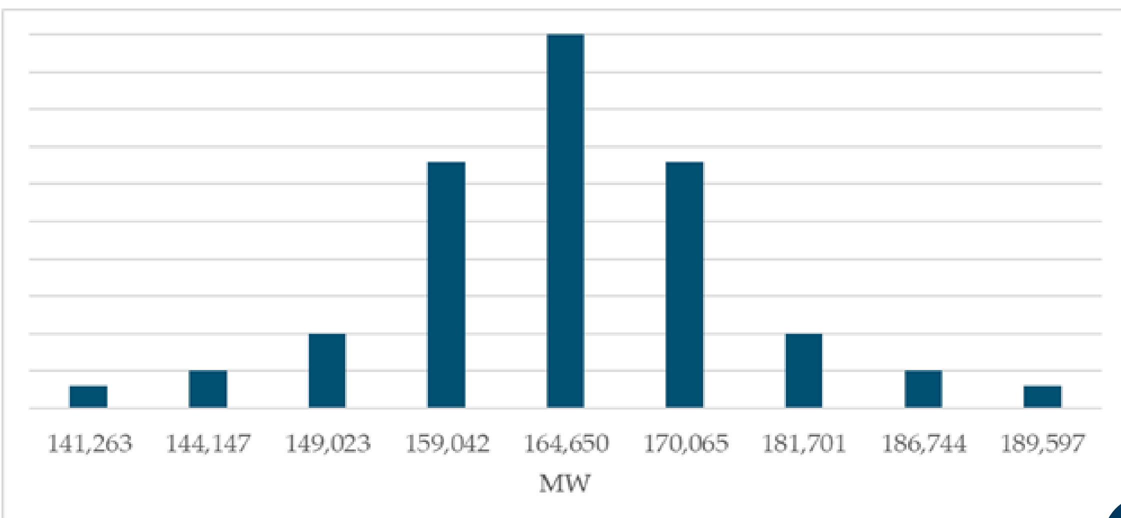


Figure 3: Western Interconnection Peak Hour Demand Variability

Given the current demand probability curve projections, the next 10 years show a similar demand variability distribution. Figure 4 represents the probability curves for each of the next 10 years, given no major changes in the variability of demand. However, this distribution will increase. Future analyses will include the June 2021 heat wave data as well as future extreme weather events, which, like the 2020 events, will change the shape of the demand curve. The demand variability distribution curve will likely widen, increasing the range of potential extreme events and the likelihood of repeating the extreme events the West has experienced over the last few years. This changing potential will continue as the West continues to experience the effects of climate change.

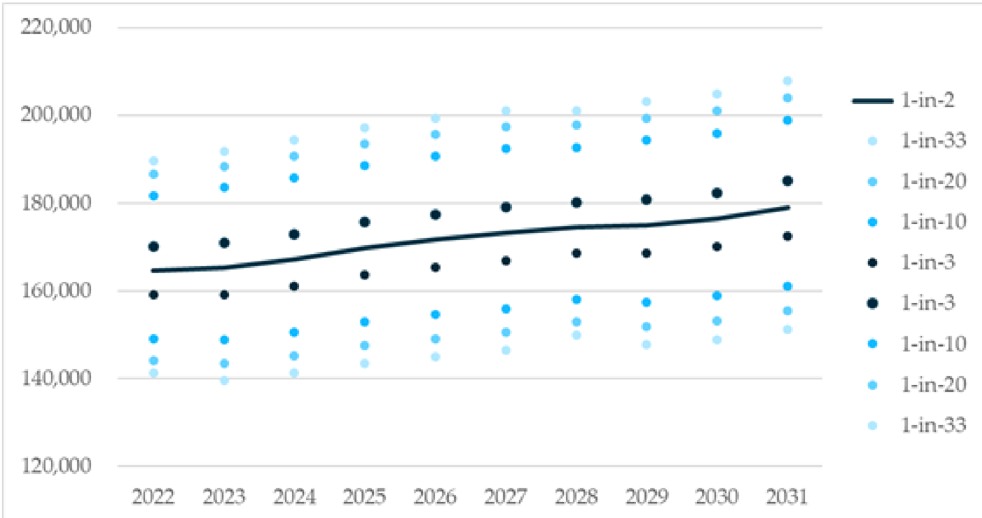


Figure 4: Interconnection Peak Demand Variability 2022–2031 (MW)

Resource Availability Variability

As with demand variability, weather is the largest driver of variability in overall resource availability. This is because the energy output of VERs is almost entirely determined by weather. Also, extreme weather events can increase variability in otherwise low-variability resources, such as natural gas freeze events.

Resource Growth

VERs will make up a large part of the resource additions over the next decade (See Figure 5). Current projections show the solar resources nearly double over that time, and while baseload resources are projected to remain relatively flat in terms of capacity, each year they make up a smaller portion of the total portfolio.

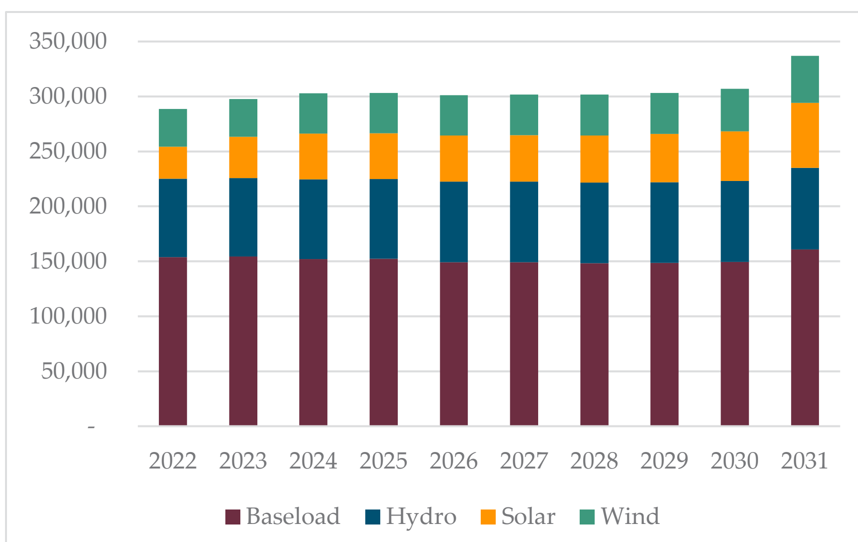
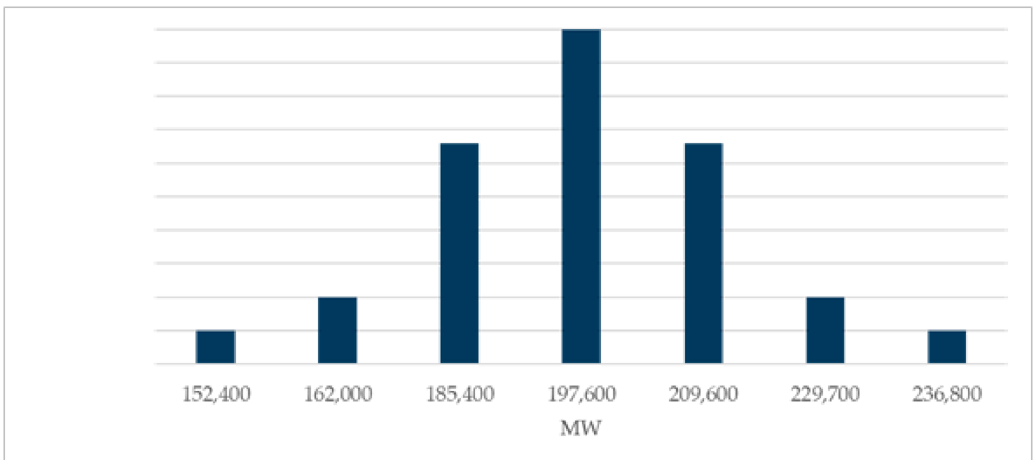


Figure 5: Western Interconnection Resource Mix Forecast 2022–2031

To meet new clean energy mandates and satisfy customer demand, VERs will likely make up a much greater portion of the resource portfolio than currently projected. At the same time, new discoveries and technology advancements may also change the make-up of future resources. For example, according to reported data from BAs, battery storage is expected to become more prevalent and viable, which is portrayed in the baseload in Figure 5.

Resource Availability

Like demand variability, the 2021 Western Assessment analysis indicates increased resource availability variability compared to the 2020 analysis. Increased VERs and changing weather patterns have altered the shape of the resource availability probability curve; the curve has widened and increased the range of potential resource availability—specifically, reduced resource availability. In 2022, at the time of the interconnection coincident peak, the expected resource availability (1-in-2) is 197,600 MW (See Figure 6). However, if a 1-in-20 event occurs, resource availability could decrease over 45,000 MW, a reduction of nearly 23%. If this situation were to occur, the interconnection would not have enough generation to meet the expected 164,650 MW peak demand, let alone any increased demand.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	116,300	199,800	128,600	131,800	134,600	138,500	139,400
Hydro	24,400	27,800	35,300	40,600	44,600	50,000	51,700
Solar	11,300	13,700	18,000	19,300	20,800	23,400	25,000
Wind	400	400	3,500	5,900	9,600	17,800	20,700

Figure 6: **Western Interconnection Peak Hour Resource Variability 2022**

Each resource type has different levels of availability driven by different influencers. The availability of baseload resources, for example, is dependent largely on forced outage rates of the generating units and does not show a lot of variability. The availability of hydro resources is typically dependent on two variables, the strength of the water year and the availability of water storage. Hydro generation is expected to be capable of producing 40,600 MW, but there is a 5% probability that output could be as little as 24,400 MW. As long-term weather and climate changes expand and intensify drought conditions in the West, the likelihood of low hydro output will increase.

During the 2022 Western Interconnection peak, utility-scale solar generation is expected to produce around 19,300 MW and wind generation is expected to produce around 5,900 MW. However, due to the high variability of these resources, under adverse conditions there is a 1-in-20 probability that solar generation may drop to as low as 11,300 MW and wind generation could drop to less than 400 MW, reductions of 41% and 93% respectively.

Demand at Risk

Traditional methods of calculating the PRM do not account for increasing variability in expected energy. Absent all utilities using energy-based probabilistic analysis, the West will continue to see hours in which the 99.98% reliability threshold cannot be maintained, even under the most optimistic demand and resource availability scenarios. These hours are called "hours at risk," and they have a greater-than-acceptable risk for a loss of load.

Based on the analysis of hours at risk below, all five subregions show many hours at risk for loss of load over the next 10 years given current PRMs. Further, as early as 2025, all subregions will be unable to maintain 99.98% reliability because they will not be able to eliminate enough hours at risk for loss of load even if they build all planned Tier 1 and Tier 2 additions and import power. If current demand and resource projections hold, entities will have to take additional actions by 2025 to reduce the number of hours at risk for load loss. To mitigate loss of load, PRMs should be increased—in some cases significantly—or other action taken to reduce the probability that demand exceeds resource availability. In addition, entities should recalibrate their PRMs whenever there is a substantial change to the variability of their demand or resource availability. Entities will need to regularly monitor the variability changes on their system caused by shifts in demand and resource additions and retirements. If the current long-term issues are not addressed immediately, they may be insurmountable when they become near-term issues.

Calculating Hours at Risk

Increasing or decreasing the PRM will affect the number of hours at risk of load loss. An examination of the hours at risk under different PRMs helps illuminate how traditional methods of calculating the PRM do not account for variability.

The probabilistic approach in this analysis compares the number of hours in which demand might exceed available resources against different PRM levels:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Determined by calculating the PRM based on the peak demand hour and applying that PRM to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach applied in this assessment.

In the assessment, any hour in which there is a chance that demand may exceed resource availability is labeled an "hour at risk." Hours at risk are not necessarily times when load loss is expected; they represent times when, if extreme conditions exist, there is a *risk* of load loss.

This part of the analysis helps identify the level of risk that exists when the Peak Demand and Fixed PRMs are used. From there, the analysis determines the PRM necessary to reduce risk, account for increased variability, and keep the system within the 99.98% reliability threshold (Total Reliability PRM). WECC does not set or mandate PRMs, so this analysis is used simply to highlight that, if the Western Interconnection is to remain 99.98% reliable for all hours, the West needs to account for the growing variability on the system. Increasing PRMs is one way of doing this. There are other ways to account for variability, but this report focuses on adjusting the PRM to do so.

A comparison of the hours at risk calculated using the Peak Demand PRM versus the Fixed PRM demonstrates how changing the PRM affects the potential hours at risk for loss of load. Figure 7 and Figure 8 show the potential hours at risk of unserved load in 2022 and the magnitude of the at-risk load for the Peak Demand PRM (13.6% for the Western Interconnection) and Fixed PRM, respectively.

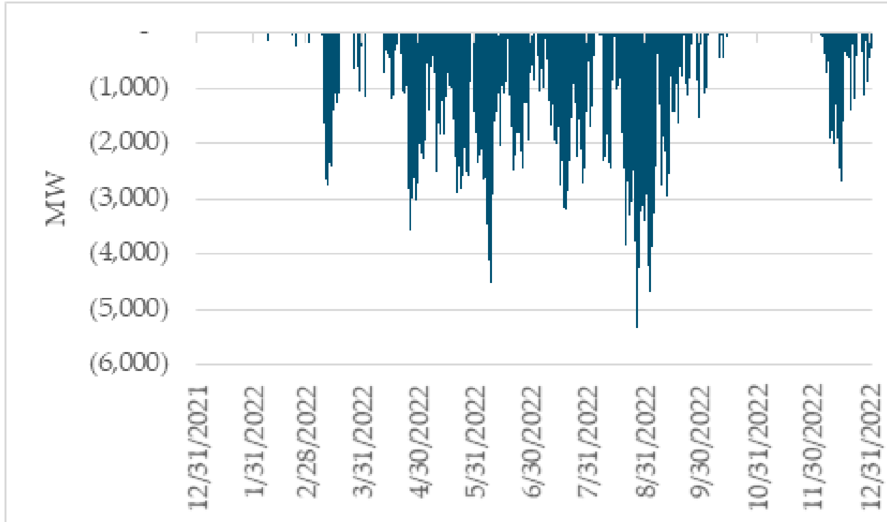


Figure 7: Magnitude of 2022 Western Interconnection Potential Loss-of-Load Hours with Peak Demand PRM (13.6%)

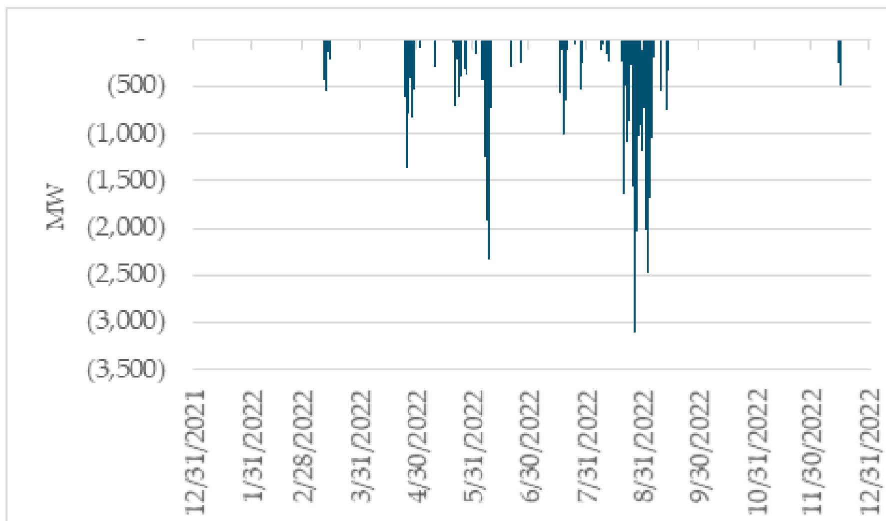


Figure 8: Magnitude of 2022 Western Interconnection Potential Loss-of-Load Hours with Fixed PRM (15%)

The Peak Demand PRM for the Western Interconnection is 13.6%. Under this PRM, the interconnection would experience 598 hours at risk, with the greatest amount of load at risk exceeding 5,300 MW in late August (See Figure 7). Most of the hours at risk occur in the shoulder seasons in which extreme weather events increase variability. Demand has historically been lower during these times, so entities have not had to hold as much generation as in other parts of the year, like the peak hour. However, increasing extreme events during these times are raising demand levels and reducing available energy generation unexpectedly, creating the potential risk for demand to exceed generation.

If entities adapt and account for this variability and hold a higher PRM, they can reduce this risk. Even a modest increase from the current 13.6% to 15% (Fixed PRM) can significantly reduce the number of hours at risk. In 2022, a 15% PRM would reduce the hours at risk from 598 to 89 (See Figure 8). However, 15% PRM still does not achieve the 99.98% risk tolerance threshold. To do so, the Western Interconnection must hold a 16.9% PRM (See Figure 9). A 16.9% PRM would achieve 99.98% reliability by reducing the demand-at-risk hours to zero, under the one-day-in-ten-year (ODITY) threshold.

Figure 9 compares the hours at risk for each of the three PRMs for the entire interconnection in 2022. It highlights the gap between PRMs that are determined using the Peak Demand PRM or Fixed PRM approaches and the Total Reliability PRM, the PRM necessary to maintain 99.98% reliability for all hours. The curve represents the number of hours at risk under the different PRMs. The hours at risk using the Peak Demand PRM and Fixed PRM are 598 and 89, respectively. The PRM necessary to account for variability on the system is 16.9%.

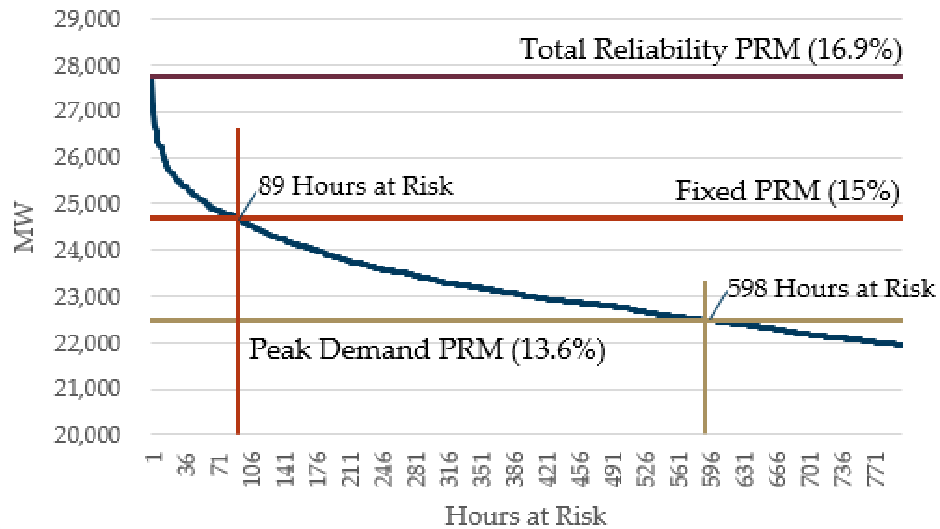


Figure 9: Subregion Hours at Risk in 2022 for Various PRMs

Subregional Hours at Risk

Each subregion has a diversity of weather and a peak season that distinguishes it from the broader Western Interconnection. To better understand the potential risks associated with various PRMs, a more granular evaluation is necessary. This section looks at demand at risk across the subregions using the same approach as was previously used for the entire interconnection. The information contained in this section highlights the diversity of reliability concerns across each subregion. For a more detailed analysis of the variability and resource adequacy risks for each subregion, see Chapter 4.

Table 1: Subregional PRMs Used in this Analysis

	Peak Demand PRM	Fixed PRM	Total Reliability PRM
NWPP-NW	13.9%	15%	23.9%
NWPP-E	12.1%	15%	16.1%
NWPP-C	14%	15%	17.8%
CAMX	18.4%	15%	21.6%
DSW	12.5%	15%	15%

Over the next 10 years, each subregion shows many hours at risk for loss of load at the Peak Demand PRM. Even if the subregions increase their PRMs to 15%, all but the DSW subregion will experience hours at risk in 2022. The CAMX subregion holds a PRM higher than 15%, yet still shows hours at risk. Beyond 2022, the DSW subregion, like the rest of the West, will need to increase its PRM higher than 15% (See Figure 10).

Figure 10: Subregion Demand at Risk for Different PRMs—2022

As the decade progresses and variability increases, the Total Reliability PRMs increase in all but the NWPP-NW subregion. This is because the NWPP-NW subregion has a hydro-heavy portfolio; so, unlike subregions with heavy baseload portfolios, the NWPP-NW will not have to replace a lot of its baseload hydro to meet future clean energy mandates. This means the stability of the existing hydro can remain while the portfolio can meet new clean energy or renewable standards. In other subregions, to meet clean energy mandates, less-variable baseload resources may be replaced with VERs. Table 2 shows the Total Reliability PRMs for each subregion over the next four years and in 2031. After 2025, the resource availability forecasts lose some significance because the analysis for years 5–10 includes the addition of Tier 3 resources. Because Tier 3 resources are only conceptual (they are not in a planning, permitting, or building phase), there is a high likelihood that they will change. In many cases, BAs report generic placeholder resources for years 5–10.

Table 2: Subregion Total Reliability PRMs 2022–2025 & 2031

	2022	2023	2024	2025	2031
NWPP-NW	23.9%	23.9%	23.5%	23.5%	22.7%
NWPP-NE	16.1%	16.7%	17.3%	17.5%	20.6%
NWPP-C	17.8%	17.7%	20.1%	20.3%	20.4%
CAMX	21.6%	20.6%	22.0%	21.8%	28.1%
DSW	15.0%	17.7%	18.7%	18.5%	19.3%

The Total Reliability PRM for each of the subregions provides an indication of how the variability on the system will increase over the next decade, given current resource and demand forecasts. Increasing the PRM is one way to manage the risk associated with increased variability, but it is not the only way. This analysis is based on the information entities have today about future resources. This analysis does not account for new technology or operational practices; it does not contemplate the role of emerging technologies like batteries; and it does not directly account for how entities will comply with future policies. So, while the analysis indicates that PRMs will need to increase to remain 99.98% reliable, WECC recognizes that there are other avenues, both known and to-be-discovered, to manage variability and keep the system reliable. Some examples include:

- Batteries and other potential storage technologies;
- Energy efficiency and other load-changing policies;
- Distributed generation;
- New technology;
- Transmission expansion; and
- Market participation.

Imports

Entities meet their PRM by building or purchasing resources within their Balancing Authority Area (BAA), contracting to import energy, or both. The changes that affect how entities conduct resource planning also affect how and when entities can rely on import capacity and the capability of the transmission system to move power. Entities that rely heavily on imported energy and do not change how they count imports could encounter resource adequacy challenges. As early as 2025, no subregions will be able to maintain 99.98% reliability because they will not be able to eliminate the hours at risk for loss of load, even if they build all planned Tier 1 and Tier 2 additions and import power.

Changes to Diversity and Import Capability

The Western Interconnection's rich diversity of generation types, peak load seasons, load patterns, and climate zones has been a great strength and underpins the design, planning, and operation of the system. Importing and exporting power are key strengths to the operation of the system. The Western power grid was designed to take advantage of this diversity, resulting in the long transmission lines and layout of the interconnection. Also, historically, weather events were localized—when one area was experiencing high demand, there was enough generation in other areas and sufficient transmission available to deliver power to compensate. For decades it was a safe assumption that, when an entity needed to import power, both the generation and transmission capability would be available to produce and move it.

Shifts in weather and climate are changing the diversity of the interconnection and each subregion's ability to rely on imports. The weather and climate events in the West are growing more frequent, longer, and more severe. Their size and location are also changing. In some cases, they are expanding, and in others they are spreading to different areas. For example, West-wide heat waves are causing coinciding demand spikes across broader areas, reducing or eliminating the power that more temperate areas have historically been able to provide to hotter areas because they need to serve native loads. Further, the resource mix is transforming to one that is more sensitive to extreme weather conditions. Solar and wind resources are affected by weather and require a greater ramping ability to offset energy variability. Other, non-variable resources are also affected by weather, e.g., batteries, hydro, and natural gas.

In addition to being less predictable and more wide-spread, extreme weather events and weather-related events like wildfires are becoming more severe in magnitude and duration. This is stressing the system in ways never experienced and resulting in energy shortages, as capacity is used to support native load or output is reduced due to extreme weather. For example, during the heat wave in August 2020, the West experienced shrinking margins in resource availability and transmission capacity, which led to rotating outages in California. As a result, planners and operators must adapt and run a system with a smaller margin than in the past.

Reliance on Imports Scenarios

The Western Assessment evaluates two scenarios, each comprising three variations, for each of the five subregions to determine the impact that imports have on resource adequacy (See Figure 11). Each hour over the next four years is examined to determine whether the subregions can meet the Total Reliability PRM or whether they will have hours at risk of load loss.

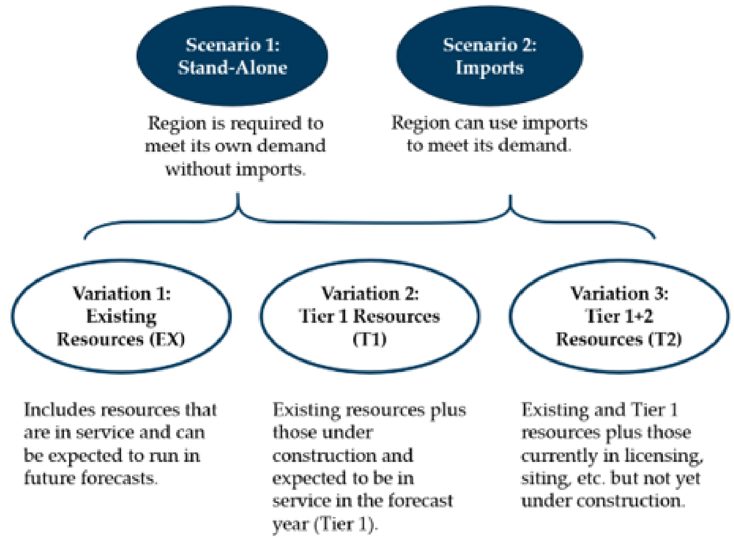


Figure 11: Western Assessment Scenarios and Variations

Scenario 1 determines whether a subregion can be resource adequate without importing energy from any other subregion. While this scenario does not reflect the reality of the system because imports occur constantly between subregions, it helps highlight how dependent each subregion is on imported energy to meet its resource adequacy needs. Additionally, this scenario provides a look at the potential impacts to a subregion when imports are limited, e.g., during an extreme weather event.

Under Scenario 2, imports are allowed between subregions. The amount of energy available for import is determined by any excess energy once all native needs have been met. Transmission assumptions are based on BA data submissions.

For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by BAs in their data submissions are the same in all three variations.

Reliance on Imports

The evaluation of each subregion under Scenario 1 shows many hours where demand is at risk because the Total Reliability PRM (99.98% reliable) cannot be met (See Figure 12). When imports are allowed under Scenario 2, the demand at risk hours decrease significantly, though only in a few cases do they disappear completely. In no case in which the subregion relies solely on existing resources do the hours at risk disappear. Tier 1 resources, and in most cases Tier 2 resources, are necessary to reduce the hours at risk. Finally, while some subregions can eliminate or greatly reduce the hours at risk in the next couple of years by building their Tier 1 and Tier 2 resources and importing power, by 2025, given current projections, all subregions will have hours at risk even under these circumstances.

Figure 12: Subregion Demand at Risk with and without Imports 2022–2025

If current demand and resource projections hold, entities will have to take additional actions by 2025 to reduce the number of hours at risk for load loss. In some cases, this action may be to build additional resources; however, resources typically take longer to build. Near-term options employed by entities may focus on increasing the availability of resources, such as delaying retirements of existing resources or temporarily relaxing environmental standards that may limit the output of existing resources. In other cases, entities may need to make operational planning changes, such as delaying or rescheduling maintenance activities. In any case, entities must act immediately to address resource adequacy issues.

The resource adequacy challenges in 2025 continue and increase in years five through 10. In all subregions the addition of Tier 1 and Tier 2 resources will not eliminate the hours at risk for loss of load (See Figure 13). The analysis of years 5–10 includes Tier 3 resources as well. However, even if entities add all the Tier 3 resources they currently project, they will not be 99.98% reliable because they will still have a significant number of hours at risk. Entities have many more options to address resource adequacy issues in the 5-to-10-year time frame than in the near-term. However, it is critical that entities act now to address years 5–10 because the magnitude of the resource adequacy challenges increases with time. If the current long-term issues are not addressed immediately, they may be insurmountable when they become near-term issues.

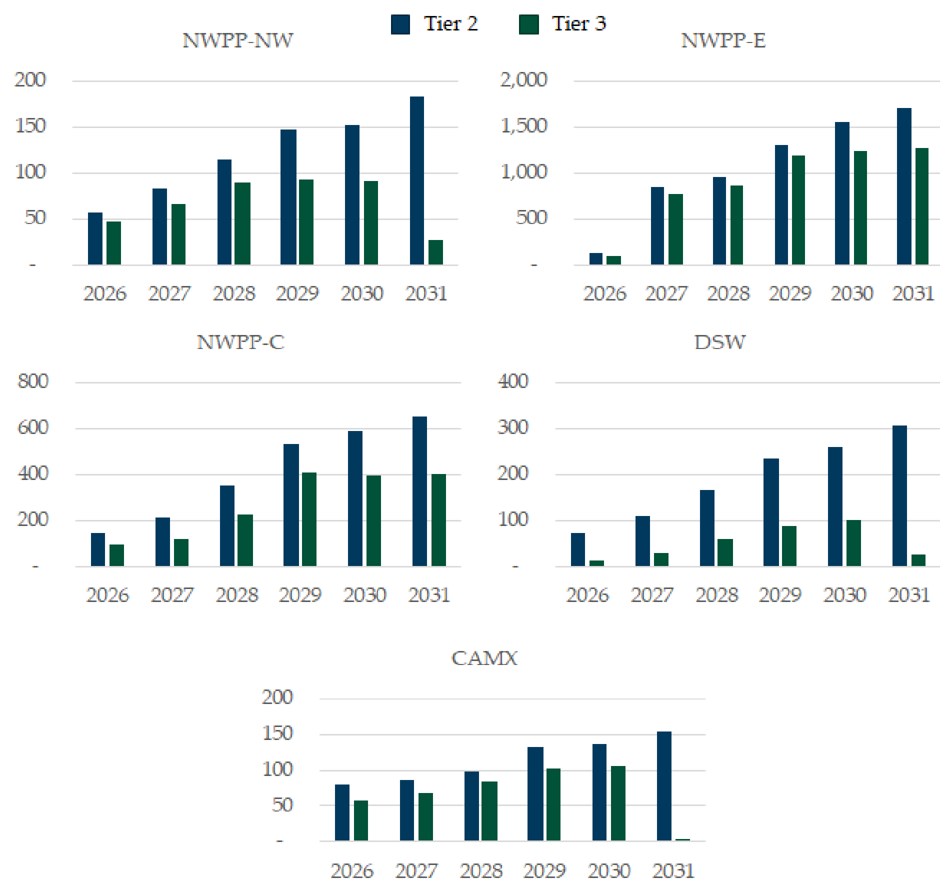


Figure 13: Subregion Hours at Risk After Imports 2026-2031

Chapter 3

Deterministic Analysis of System Condition Scenarios

System Condition Scenarios

With the 2021 Western Assessment of Resource Adequacy (Western Assessment), WECC used additional tools to examine the potential impacts of extreme conditions in the near-term. Unlike the rest of this assessment, which uses probabilistic analysis, this section uses deterministic analysis to examine a few specific operational scenarios. A deterministic analysis allows the user to look at a wide variety of system characteristics, such as energy transfers, cost of serving load, unserved load, market reliance, etc. However, this section is focused on examining the extent to which Balancing Authorities (BA) rely on other areas to serve load through energy transfers during extreme conditions. While these scenario analyses are not intended to address a broad spectrum of issues, future deterministic analyses could be expanded to examine a breadth of potential operational impacts.

Operational Analysis

Resource adequacy challenges span multiple planning time frames. Other sections of this report focus on both the near-term (1–4 years) and long-term (5–10 years) time frames. This section is focused on the near-term because the challenges of ensuring resource adequacy in the near-term are unique and require different solutions than the long-term time frame. Many of the solutions that can ensure resource adequacy in the long-term are difficult, or impossible, to implement in the near-term. For example, new resources typically take more than four years to plan, approve, and build. While there are exceptions—most notably the rapid deployment of batteries in California over the last two years—for the most part, new resources are not a viable way to address near-term resource adequacy shortfalls. Rather, operational planning solutions must be put in place because they are near-term solutions that can be implemented quickly and without requiring modifications to infrastructure. Operational planning solutions require more detail about system conditions than the probabilistic analysis in this assessment provides. They require a more detailed simulation of system conditions and analysis of how the system responds to understand the near-term resource adequacy risks and illuminate the potential mitigation strategies available to operational planners.

Probabilistic and deterministic analyses work together for this evaluation because the probabilistic results feed into and inform the deterministic model. The probabilistic analysis looks at a range of potential demand and resource availability conditions. Based on the scenario selected, information from some of those potential conditions is taken out of the probabilistic assessment and fed into the deterministic model.

Deterministic Approach

Fixed parameters make a deterministic analysis an appropriate choice for scenario analyses in the near-term. A deterministic analysis assumes that load, generation resources, and other model parameters are known. Using this approach allows an evaluation of how existing or soon-to-be completed generators would likely operate under defined circumstances based on the scenario being examined. This can highlight deficiencies and inform strategies for mitigation.

This scenario analysis uses a zonal production cost model. The zonal model considers each BA as a zone and groups its resources to meet its load. Then, if necessary, the model exports generation to other zones to fulfill deficiencies. The zonal model does not consider individual buses or transmission lines but does limit transfers between zones based on aggregate transmission limitations. Though congestion and other transmission constraints are important considerations in the overall performance and efficiency of the grid, this analysis is more concerned with the ability of the current and prospective generation resources to meet load than the ability of the individual transmission lines to move power.

The parameters and inputs used in the zonal model are consistent with the Multi-area Variable Resource Integration Convolution (MAVRIC) assumptions and outputs. The generation portfolio for each year is consistent between both models and the annual demand curve and generation curve for variable resources (e.g., solar, wind, and hydro) for each load zone is defined by MAVRIC output.

This section provides results from a deterministic scenario analysis of three system condition scenarios:

- Expected Case;
- High Demand Case; and
- High Demand without Hoover Dam or Glen Canyon Dam (Drought Case).

Scenarios

Scenario 1: Expected Case

The Expected Case represents the expected or most likely scenario based on historical performance. Statistically, the expected case is the 50th percentile result, therefore load curves for each load zone and generation curves for the variable resources match the 50th percentile curves produced in the probabilistic assessment. Running this case establishes a baseline to which the other scenarios can be compared. Comparing the extreme case scenarios to the expected case helps identify the specific impacts of the extreme conditions being studied.

Scenario 2: High Demand Case

The High Demand Case differs from the Expected Case in that it assumes that the load curve is the 97th percentile of load, or the 1-in-33 case. Recent extreme weather has significantly increased demand on the system. While historically rare, the impact of extreme demand is significant, as evidenced in the August 2020 heat wave, which was a 1-in-30 event, and again in the June 2021 heat wave, and 1-in-1,000 event. If the extreme temperature trend continues, this level of demand could occur much more often than current analysis suggests.

Scenario 3: Drought Case

The Drought Case builds on the High Demand scenario by reducing the amount of energy generated by specific hydro plants. Studies indicate that Hoover Dam (2,074 MW nameplate capacity) and Glen Canyon Dam (1,296 MW nameplate capacity) could cease generation by 2026. These dry conditions have and will continue to negatively affect the amount of energy that can be generated by hydro plants as reservoirs and other bodies of water experience low water levels. For this reason, this case excludes the operational capacity of the Hoover Dam and Glen Canyon Dam in addition to the 97th percentile of demand.

Results and Findings

The probabilistic analysis looks at imports across the West to determine how reliant subregions are on imports and whether those imports will be available. The deterministic analysis allows a more detailed evaluation of how power moves across the interconnection given the system conditions assumed in the scenario being studied. The following maps compare the system during an evening hour in June of 2022 across the three scenarios described above. This hour represents a time of high demand and resource variability. Although all hours of 2022 were studied, this hour was chosen to illustrate significant changes to energy transfers as extreme conditions arise.

Power Flow Across the Interconnection

For all three scenarios, energy moves in the "doughnut" pattern of power flow in the West: generally, excess energy from the north and east moves toward the south and west (See Figure 1). For this June hour, demand is typically lower than it is during the expected peak hour, while variability is greater due to the change of the season and hour of the day. In the Expected Case, energy flows out of Arizona, Montana, the Northwest, and Northern California and flows into southern Nevada, New Mexico, Southern California, and Mexico.

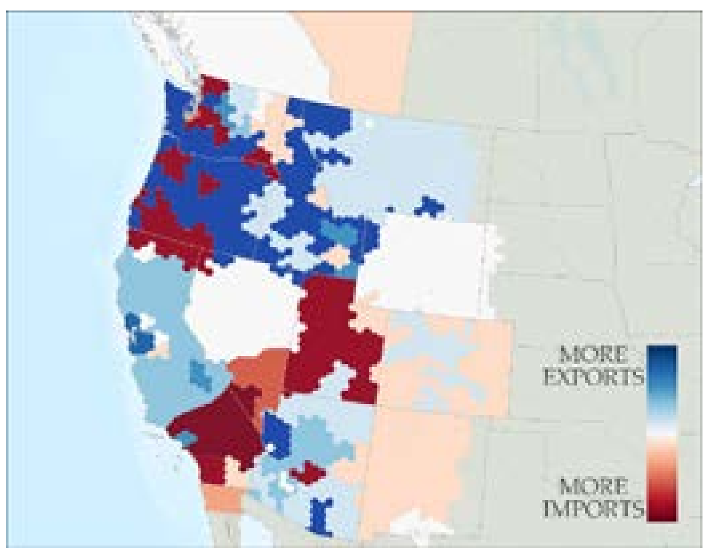


Figure 1: Western Assessment Expected Case - 2022

When the interconnection experiences extreme demand, excess resources being held in reserve will come online to help serve the increase in load. This can be seen in the eastern part of the interconnection where Colorado and New Mexico flip from importing power to exporting power (Compare Figure 2 to Figure 1). Northern California, with the higher demand, must import power and no longer has excess resources to share with others. The Northwest and Arizona continue to export while Southern California and Nevada continue to import.

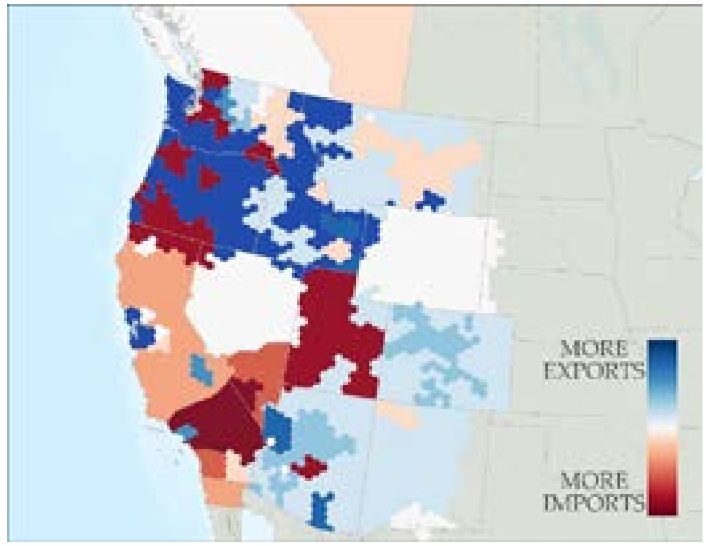


Figure 2: Western Assessment High Demand Case—2022

The Drought Case compounds the extreme conditions with the removal of the generation from Glen Canyon Dam and Hoover Dam, which changes import and export capability across the interconnection. The Desert Southwest subregion can no longer export (Compare Figure 3 to Figures 1 and 2). Overall, Colorado, Arizona, and parts of Utah are now importers, unlike in the High Demand Case, and New Mexico increases exports to help supply the load in these areas. With the change in the Desert Southwest, the flow of energy is disrupted through the south, which causes larger impacts in the north and east sides of the "doughnut." More energy flows through the Northwest, down into Northern California, and then further on to Southern California, to make up for the loss of generation from the two hydro plants. This represents how a subregional change such as the loss of two large generating resources can have far-reaching impacts across the interconnection.

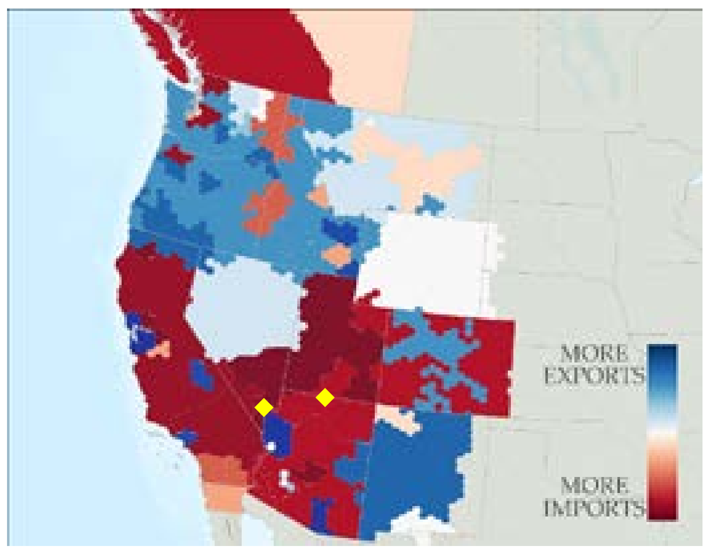


Figure 3: Western Assessment Drought Case (High Demand without Hoover or Glen Canyon Dams)—2022

Reliance on Imports

As the extreme scenarios compound from the High Demand Case to the Drought Case, the amount of energy an area can export may decline because the area is using more of its resources to meet its own load. In the Drought Case, the removal of Hoover Dam and Glen Canyon Dam left less energy for export to areas outside the Desert Southwest. These areas needed to import power to meet their own demand, and exports from New Mexico increased to make up for the loss of generation from the dams. Under extreme conditions like the Drought Case, the availability of imports across the interconnection may be reduced. As a result, areas that rely on imports to remain resource adequate may suffer load loss consistent with the demand-at-risk findings in the probabilistic analysis.

Timing of Unserved Load

The purpose of this analysis was to examine how power moves across the interconnection under different extreme scenarios, not to identify times and locations of unserved load. This is because load loss is expected in a West-wide extreme event like those examined above. However, it is worth noting that the expected loss of load in the High Demand Case occurred during off-peak hours—at night and on Sundays. These may not be times that are traditionally regarded as high-risk; however, the assessment indicates that the risk of load loss is increasing during off-peak hours, especially as variable resources make up a larger percentage of an area’s generation portfolio. System operations planning personnel should take a closer look at these hours and consider potential mitigation strategies. A more in-depth analysis using additional models (e.g., nodal production cost model, detailed power flow model) and data (e.g., firm contracts) is needed to more accurately identify and better understand the hours and locations of potential load loss.

Future Considerations

The inclusion of scenario assessments using a deterministic zonal model is new to the 2021 Western Assessment. The cursory evaluation of the above scenarios provides valuable insight into the potential impacts of extreme events on power flows across the interconnection. This kind of analysis can provide great value in evaluating resource adequacy, and more detailed analysis may provide important information on potential near-term risks. While probabilistic analysis identifies potential risks, deterministic analysis examines the behavior of the system given specific circumstances. Together, these two techniques provide a way to identify near-term risks, understand them, and begin to address them. WECC will continue refining the use of these methods to enhance its resource adequacy assessment work.

Chapter 4

Supplemental Subregion Results

Northwest Power Pool—Northwest

Subregion Results—NWPP-NW

This assessment uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances where there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level (See Chapter 1) and within each of the five subregions:

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

This section focuses on the NWPP-NW subregion, a traditionally winter peaking area that includes British Columbia, Washington, Oregon, and parts of Montana, Idaho, and California. The peak season in the NWPP-NW is shifting and can occur in winter or summer depending on the year.

The results cover three areas of the probabilistic assessment:

1. Variability
2. Demand at Risk
3. Imports

Figure 1: NWPP-NW Subregion Map

Variability

The Western Assessment analyzes both demand and resource variability. For a broader discussion of variability in the Western Interconnection, see Chapter 2.

Demand Variability

Extreme weather is a significant driver of demand variability. This section provides information on demand expectations in the near-term and potential demand variability over the next 10 years.

E In 2022, the expected peak demand for the NWPP-NW subregion is 34,819 MW.

33% There is a 1-in-3 probability (33%) that the demand could increase to 36,147 MW, a 4% increase.

3% There is a 1-in-33 probability (3%) the peak demand could reach 38,660 MW. This is a change of more than 11% from expected demand levels.

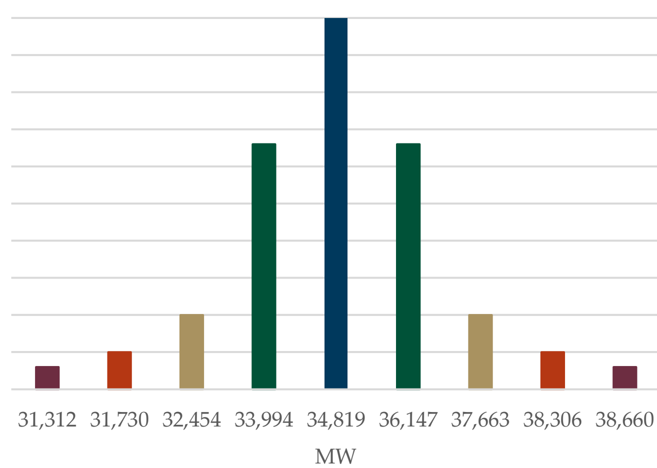


Figure 2: **NWPP-NW 2022 Peak Hour Demand Variability**

Figure 3 shows the probability curves for each of the next 10 years, assuming no major changes in the variability of demand, such as extreme weather events. Given the rapid and unpredictable changes occurring on the system, the variability of demand is likely to increase beyond what the figure shows over the next 10 years.

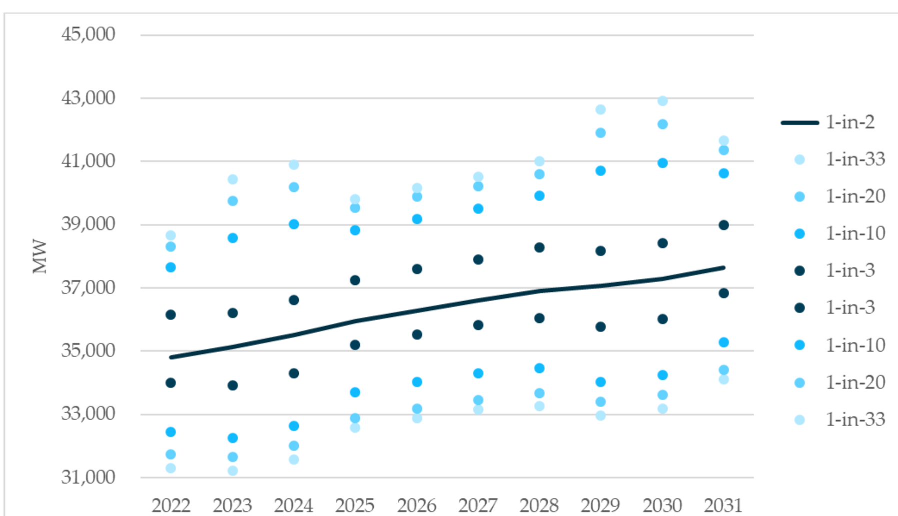


Figure 3: **Peak Demand Variability in NWPP-NW Subregion 2022–2031**

Resource Availability

The NWPP-NW subregion has over two-thirds of the hydro capacity in the interconnection. The resource mix in the subregion is projected to remain relatively unchanged over the next decade.

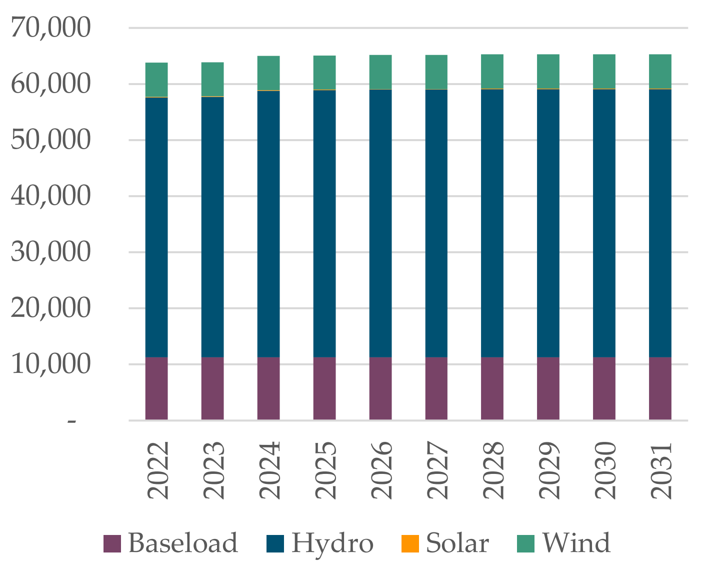


Figure 4: NWPP-NW Expected Generation Mix 2022–2031

Baseload resources (coal, nuclear, and natural gas) are expected to remain constant over the next 10 years at just over 11,000 MW.

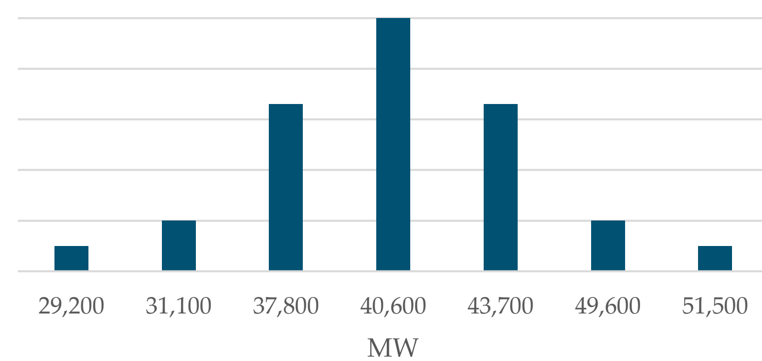
In 2022, the NWPP-NW subregion will have 46,300 MW of hydro capacity. This will grow by 1,500 MW over the next 10 years.

Wind resources are forecast for 6,100 MW in 2022 and will remain constant over the next 10 years.

Solar resources will grow negligibly over the next decade.

Of the more than 60,000 MW of nameplate capacity, the NWPP-NW subregion is expected to have 40,600 MW of available generation during its peak hour in 2022.

Low resource availability caused by a 1-in-20 weather event could reduce this to 29,200 MW. In this scenario, with an expected peak demand of 41,085 MW, the NWPP-NW would need to rely on imports to be resource adequate.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	8,500	8,900	9,800	10,100	10,300	10,600	10,600
Hydro	20,700	22,200	27,800	29,700	31,700	35,200	36,200
Solar	-	-	-	-	-	-	-
Wind	-	-	200	800	1,700	3,800	4,700

Figure 5: 2022 Peak Hour Resource Variability

Demand at Risk

When, during a given hour, the reliability threshold (99.98% in this assessment) cannot be maintained, that hour is called an hour at risk because it has a greater than acceptable risk for load loss. Increasing or decreasing the PRM will affect the number of hours at risk. This part of the assessment compares the number of hours at risk for three PRMs:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Applied to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach.

The NWPP-NW subregion is dual-peaking, meaning its highest demand hour falls in the winter or summer, depending on the year.

In 2022, the Peak Demand PRM (13.9%) results in 2,108 hours in which demand is at risk of not being served. Most of these hours at risk occur from December through March. The hour with the greatest risk is in late March, with over 4,000 MW at risk.

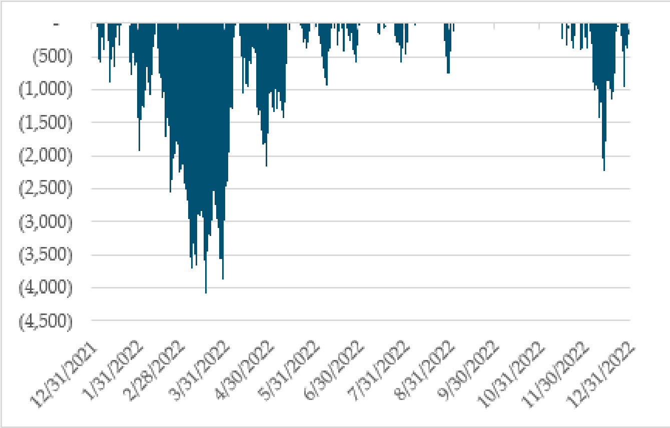


Figure 6: NWPP-NW 2022 Demand at Risk—Peak Demand PRM (13.9%)

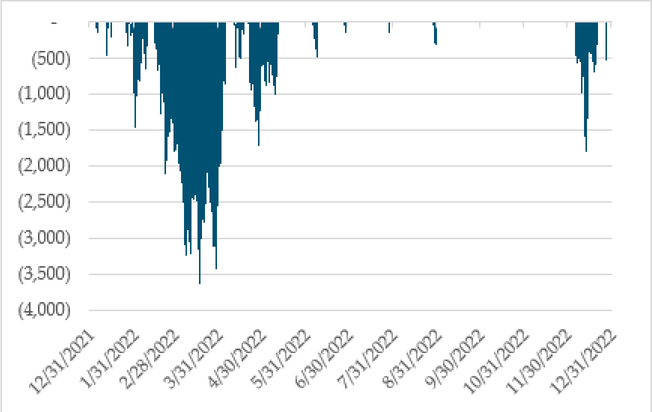
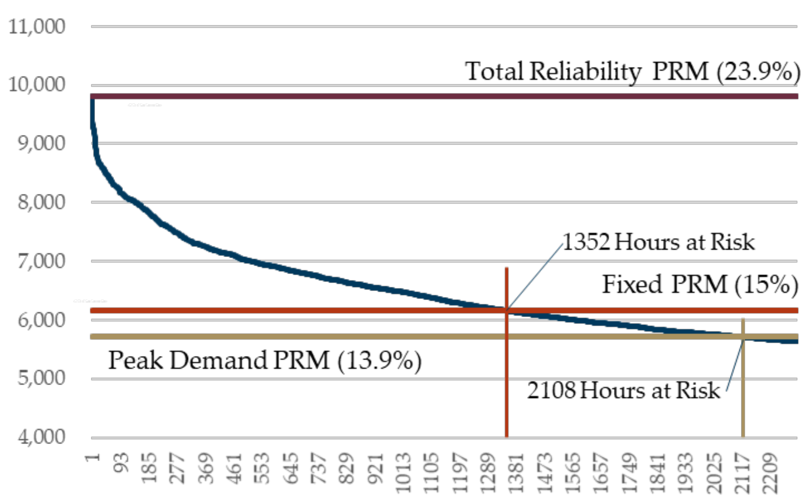


Figure 7: NWPP-NW 2022 Demand at Risk—Fixed PRM (15%)

Using the Fixed PRM (15%) reduces the number of hours at risk to 1,352. Most of the hours at risk are in late winter; however, the hour with the greatest amount of risk is in late March, with over 3,500 MW at risk.



With a Peak Hour PRM (13.9%), the NWPP-NW subregion has 2,108 hours at risk in 2022.

The Fixed PRM reduced the number of hours in which demand is at risk to 1,352.

In 2022, a 24% PRM (9,802 MW) will allow the NWPP-NW subregion to reduce hours at risk for load loss enough to remain 99.98% reliable. This number is expected to remain the same through 2025.

Figure 8: NWPP-NW 2022 Demand at Risk with Different PRMs

Years	Peak Demand (MW)	Total Reliability PRM (%)	Total Reliability PRM (MW)
2022	41,084	23.9%	9,802
2023	41,440	23.9%	9,897
2024	41,801	23.5%	9,822
2025	42,121	23.5%	9,878
2026	42,384	23.4%	9,897
2027	42,683	23.2%	9,883
2028	42,943	23.1%	9,930
2029	43,064	23.3%	10,017
2030	43,328	22.9%	9,910
2031	43,629	22.7%	9,924

Imports

This section evaluates the role of imports by examining two scenarios, each comprising three variations (See Figure 9). Each hour over near-term (years 1–4) and long-term (years 5–10) is examined to determine whether the subregion has hours at risk of load loss. For a discussion of the role of imports in resource adequacy, see Chapter 2.

Scenario 1 determines whether a subregion can be resource adequate without importing energy. In Scenario 2, imports are allowed. For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by Balancing Authorities (BA) in their data submissions are the same in all three variations.

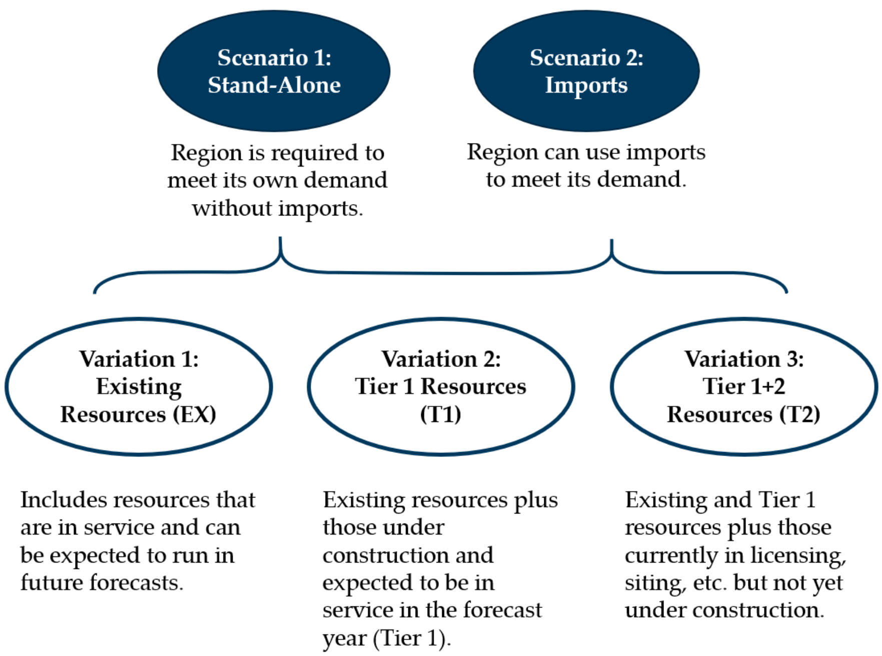


Figure 9: Western Assessment Scenarios and Variations

Near-Term Analysis (Years 1–4)

Figure 10: Demand at Risk Before Imports 2022–2025 (Hours)

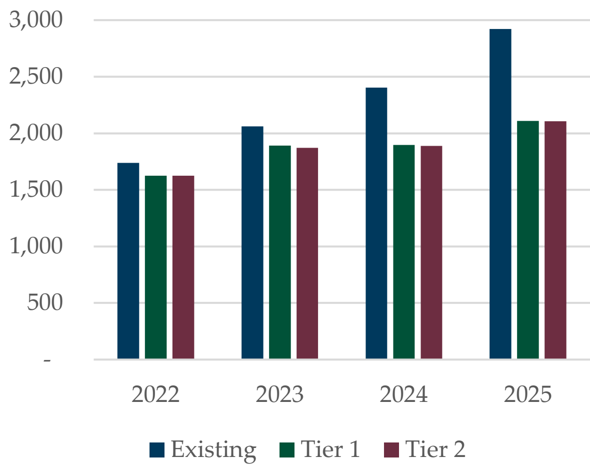
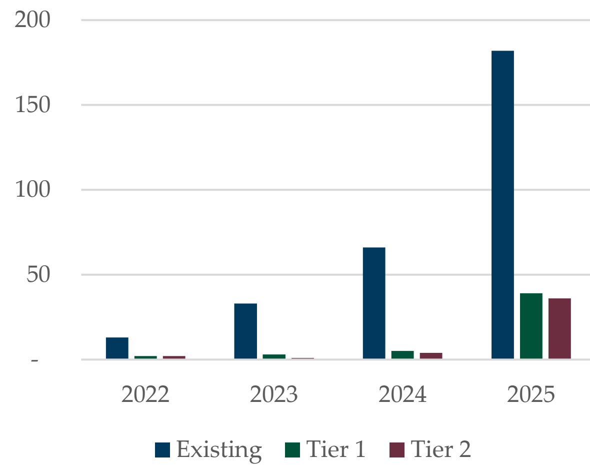


Figure 11: Demand at Risk After Imports 2022–2025 (Hours)



Before Imports

In 2022, without imports, the NWPP-NW subregion has 1,600 hours of demand at risk, meaning the subregion is not 99.98% reliable. This is equal to a potential 1,100 GWh of unserved energy. This increases to 2,100 hours and 2,300 GWh at risk by 2025. While the NWPP-NW generally exports power to other areas, it is highly reliant on imports to maintain reliability (Figures 10 and 12).

After Imports

In 2022, with imports, the risk of unserved demand is reduced to near zero for both hours and energy. By 2025, imports help reduce the risk of unserved demand to less than 40 hours and about 5 GWh of energy (Figures 11 and 13). However, despite the reduction in risk after imports, the NWPP-NW subregion will not be able to eliminate all hours at risk (Figures 11 and 13).

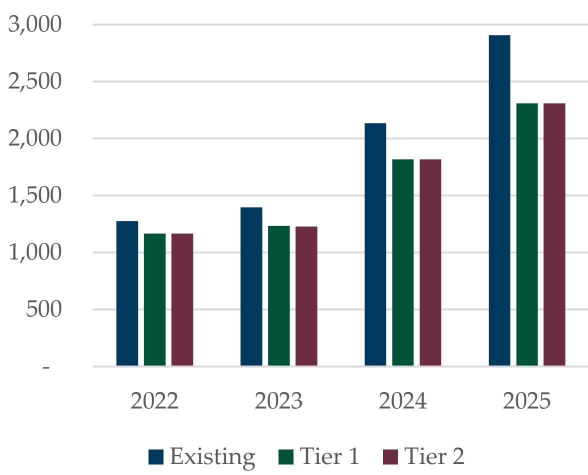


Figure 12: Demand at Risk Before Imports 2022–2025 (GWh)

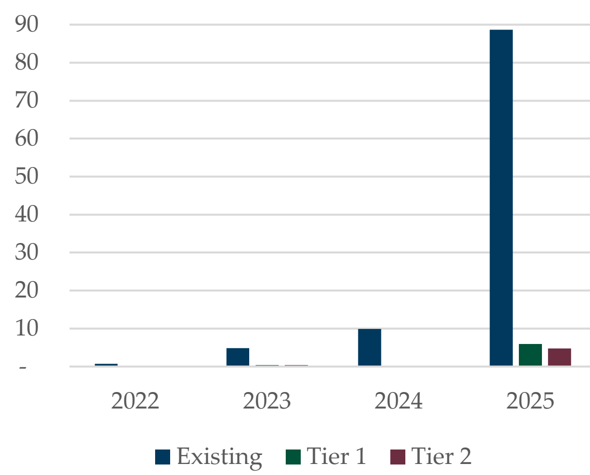


Figure 13: Demand at Risk After Imports 2022–2025 (GWh)

Long-Term Analysis (Years 5–10)

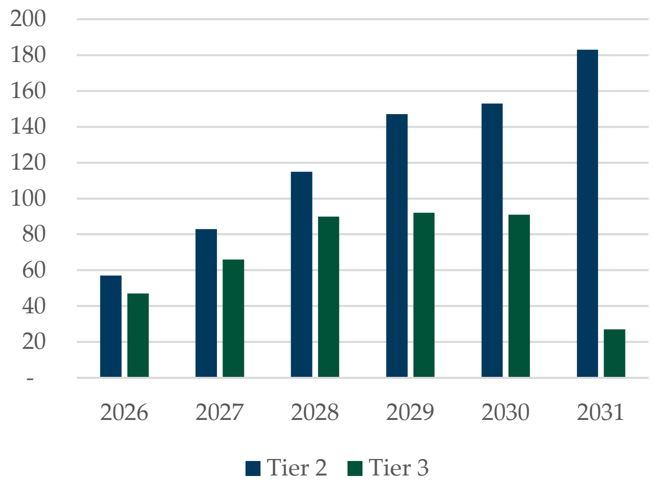


Figure 14: Demand at Risk After Imports 2026–2031 (Hours)

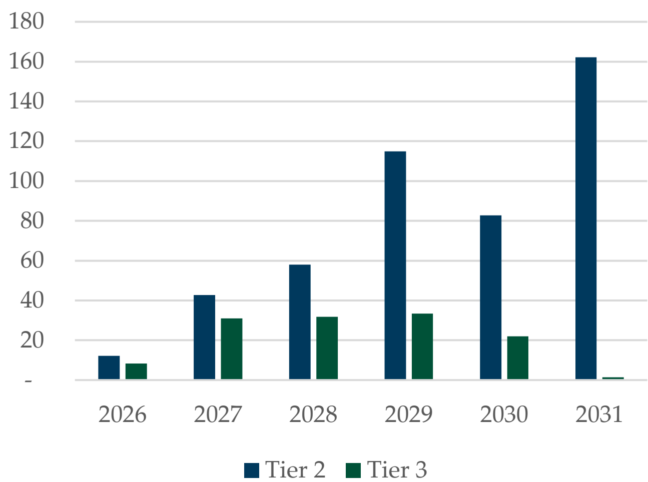


Figure 15: Demand at Risk After Imports 2026–2031 (GWh)

After Imports

Given demand and resource projections over the next 10 years, a PRM of 22.7% would achieve 99.98% reliability in 2031. However, without imports, the current resource addition plans will not achieve this PRM. Even with all planned Tier 1, 2, and 3 additions in service *and* imports, the NWPP-NW subregion has hours at risk each year from 2026 through 2031. With all Tier 2 resources built, the subregion still has 183 hours and 162 GWh of demand at risk in 2031. Even with all Tier 3 resources, the subregion still has 27 hours and 1 GWh of demand at risk in 2031.

Chapter 4

Supplemental Subregion Results

Northwest Power Pool—Northeast

Subregion Results—NWPP-NE

This assessment uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances where there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level (See Chapter 1) and within each of the five subregions:

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

This section focuses on the NWPP-NE subregion, a winter peaking area that includes Alberta and parts of Idaho, Montana, and Wyoming.

The results cover three areas of the probabilistic assessment:

1. Variability
2. Demand at Risk
3. Imports

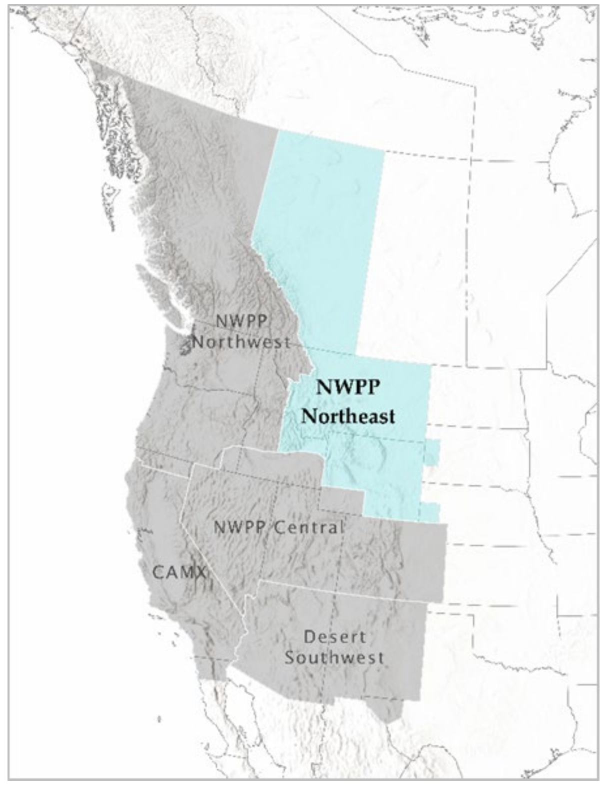


Figure 1: NWPP-NE Subregion Map

Variability

The Western Assessment analyzes both demand and resource variability. For a broader discussion of variability in the Western Interconnection, see Chapter 2.

Demand Variability

Extreme weather is a significant driver of demand variability. This section provides information on demand expectations in the near-term and potential demand variability over the next 10 years.

E In 2022, the expected peak demand for the NWPP-NE subregion is 16,709 MW.

33% There is a 1-in-3 probability (33%) that the demand could increase to 16,986 MW, a 2% increase.

3% There is a 1-in-33 probability (3%) the peak demand could reach 17,640 MW. This is a change of more than 6% from expected demand levels.

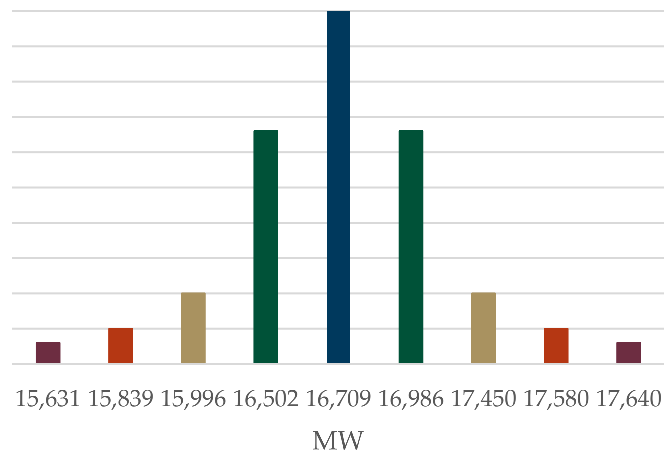


Figure 2: **NWPP-NE 2022 Peak Hour Demand Variability**

Figure 3 shows the probability curves for each of the next 10 years, assuming no major changes in the variability of demand, such as extreme weather events. Given the rapid and unpredictable changes occurring on the system, the variability of demand is likely to increase beyond what the figure shows over the next 10 years.

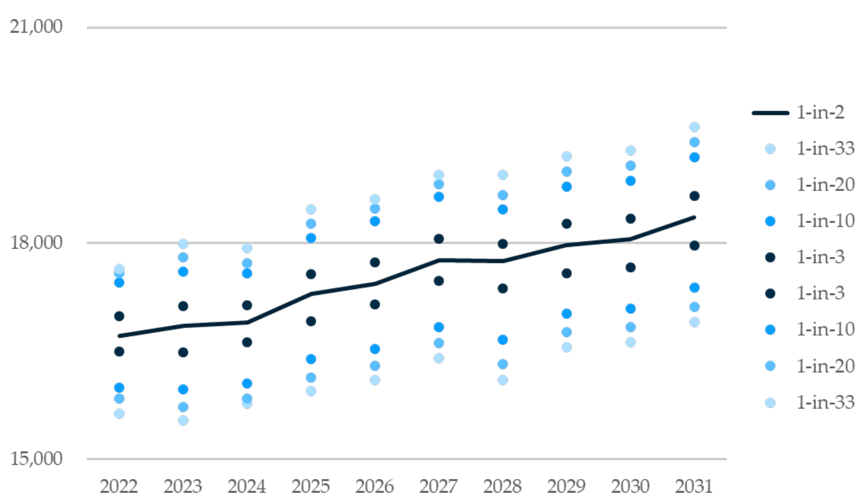


Figure 3: **Peak Demand Variability in NWPP-NE Subregion 2022–2031**

Resource Availability

The NWPP-NE subregion is a baseload-heavy subregion with over 68% of its resource capacity being coal or natural gas. The total resource mix is projected to grow in the next 10 years.

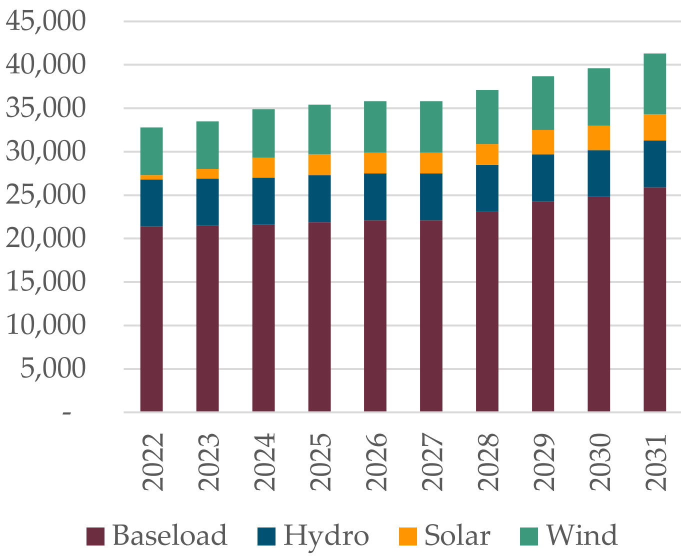


Figure 4: NWPP-NE Expected Generation Mix 2022–2031

In 2022, the NWPP-NE subregion will have 17,376 MW of baseload capacity with 5,352 MW under construction or planned.

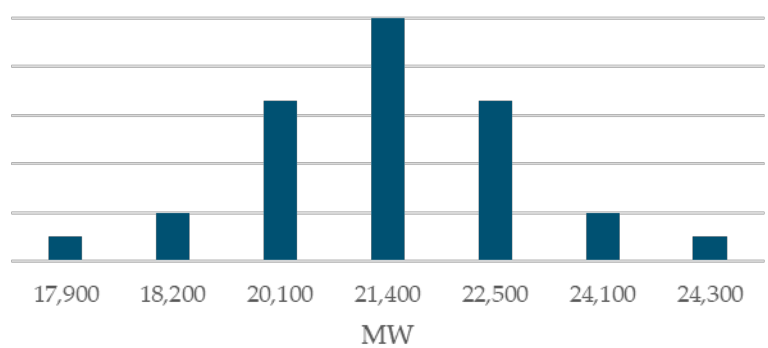
Hydro resources in the NWPP-NE subregion are projected to remain the same over the next decade, at 5,400 MW.

Wind resources are forecast for 3,194 MW in 2022, with over 3,000 MW under construction or planned.

Solar resources will more than double in the next decade.

Of the nearly 33,000 MW of nameplate capacity, the NWPP-NE subregion is expected to have 21,400 MW of available generation during its peak hour in 2022.

Low resource availability caused by a 1-in-20 weather event could reduce this to 17,900 MW. In this scenario, with an expected peak demand of 16,709 MW, the NWPP-NE would be resource adequate.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	16,500	16,800	17,900	18,100	18,300	18,600	18,600
Hydro	1,400	1,400	15,000	1,600	1,700	1,800	1,900
Solar	-	-	-	-	-	-	-
Wind	-	-	700	1,700	2,500	3,700	3,800

Figure 5: 2022 Peak Hour Resource Variability

Demand at Risk

When, during a given hour, the reliability threshold (99.98%) cannot be maintained, that hour is called an hour at risk because it has a greater than acceptable risk for load loss. Increasing or decreasing the PRM will affect the number of hours at risk. This part of the assessment compares the number of hours at risk for three PRMs:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Applied to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach.

In 2022, the Peak Demand PRM (12.1%) results in 961 hours in which demand is at risk of not being served. Most of these hours at risk occur from December through March. The hour with the greatest risk is in late December, with 600 MW at risk.

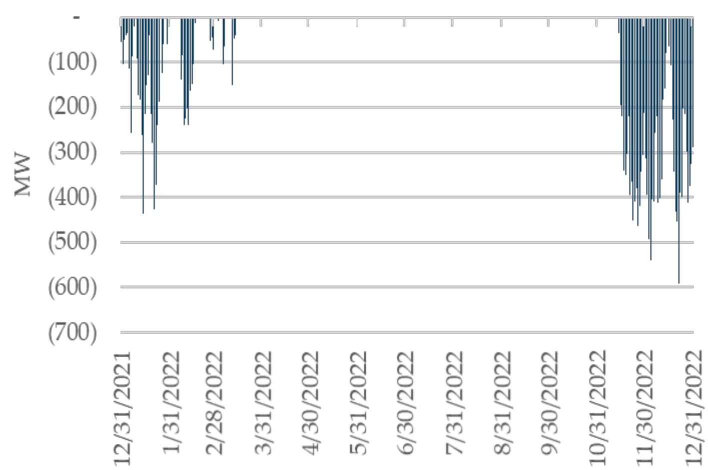


Figure 6: NWPP-NE 2022 Demand at Risk—Peak Demand PRM (12.1%)

Using the Fixed PRM (15%) reduces the number of hours at risk to 15. Most of the hours at risk are in early winter. The hour with the greatest amount of risk is in late December, with 169 MW at risk.

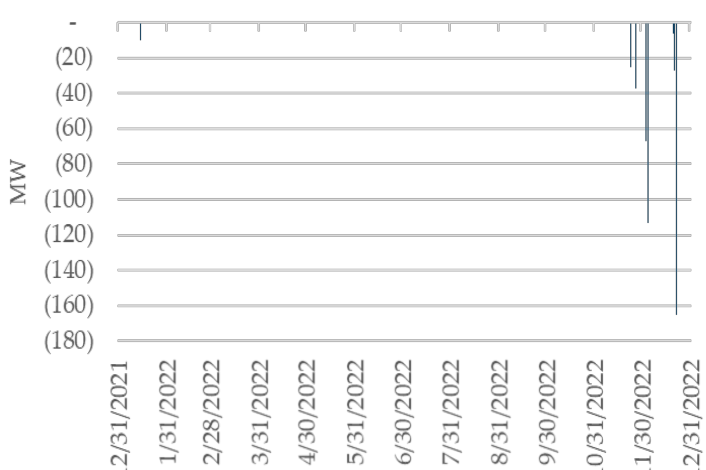
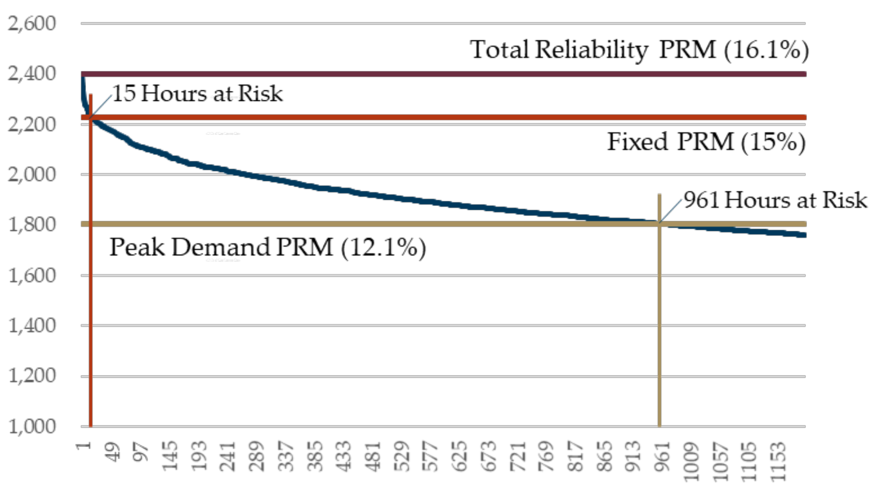


Figure 7: NWPP-NE 2022 Demand at Risk—Fixed PRM (15%)



With a Peak Hour PRM (12.1%), the NWPP-NE subregion has 961 hours at risk in 2022.

The Fixed PRM reduced the number of hours in which demand is at risk to 15.

In 2022, a 16.1% PRM (2,399 MW) will allow the NWPP-NE subregion to reduce hours at risk for load loss enough to remain 99.98% reliable. This number is expected to increase to 17.5% (2,679 MW) by 2025.

Figure 8: NWPP-NE 2022 Demand at Risk with Different PRMs

Years	Peak Demand (MW)	Total Reliability PRM (%)	Total Reliability PRM (MW)
2022	14,865	16.1%	2,399
2023	15,083	16.7%	2,521
2024	15,126	17.3%	2,619
2025	15,305	17.5%	2,679
2026	15,472	17.9%	2,767
2027	15,590	17.8%	2,768
2028	15,715	18.1%	2,852
2029	15,835	18.2%	2,881
2030	15,927	19.3%	3,081
2031	16,068	20.6%	3,318

Imports

This section evaluates imports by examining two scenarios, each comprising three variations (See Figure 9). Each hour over near-term (years 1–4) and long-term (years 5–10) is examined to determine whether the subregion has hours at risk of load loss. For a discussion of the role of imports in resource adequacy, see Chapter 2.

Scenario 1 determines whether a subregion can be resource adequate without importing energy. In Scenario 2, imports are allowed. For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by Balancing Authorities (BA) in their data submissions are the same in all three variations.

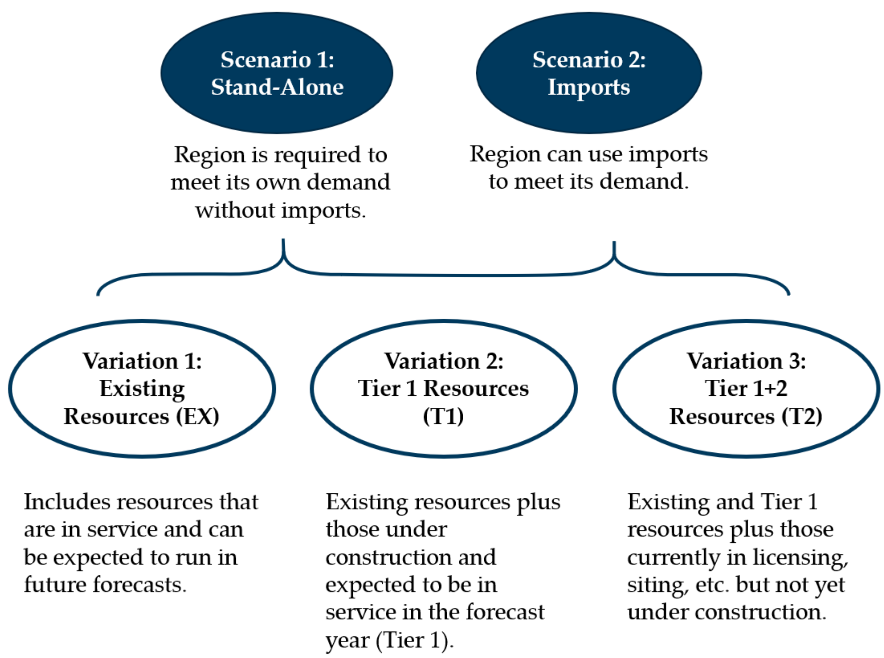


Figure 9: Western Assessment Scenarios and Variations

Near-Term Analysis (Years 1–4)

Figure 10: Demand at Risk Before Imports 2022–2025 (Hours)

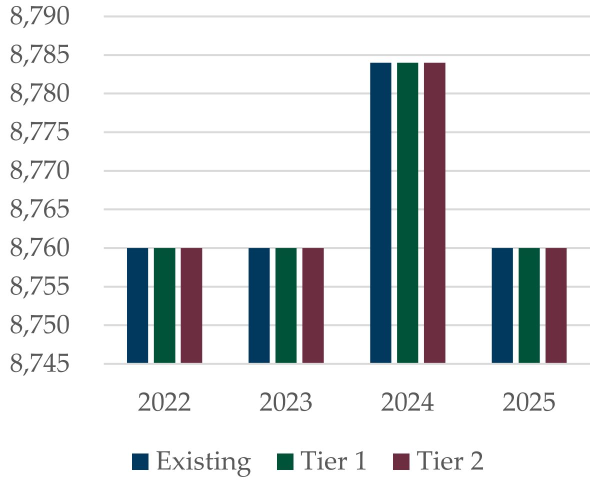
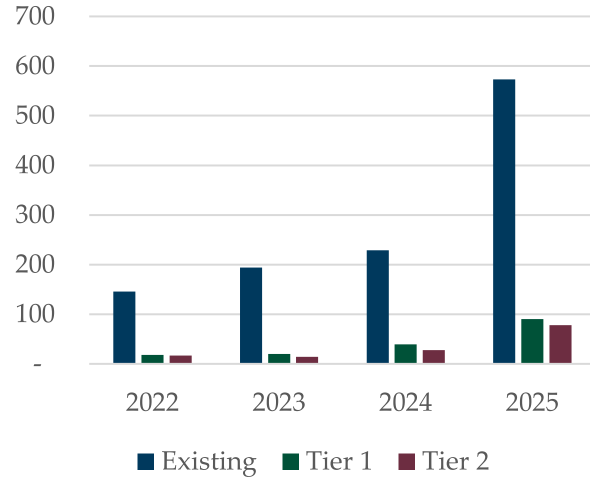


Figure 11: Demand at Risk After Imports 2022–2025 (Hours)



Before Imports

The NWPP-NE subregion is short when comparing the expected demand to expected energy, so all hours are reported as demand at risk hours (Figures 10 and 12). However, the deficit is made up through contracts that WECC does not include in the Western Assessment.

After Imports

In 2022, with imports, the risk of unserved demand is significantly reduced to 17 hours and 2 GWh. By 2025, imports help reduce the risk of unserved demand to 78 hours and about 29 GWh of energy (Figures 11 and 13).

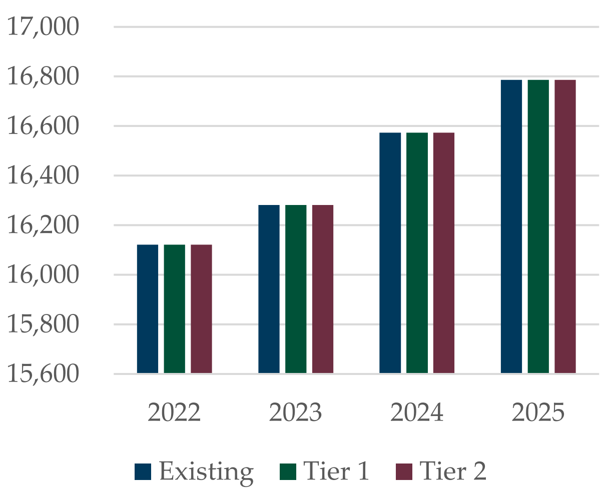


Figure 12: Demand at Risk Before Imports 2022–2025 (GWh)

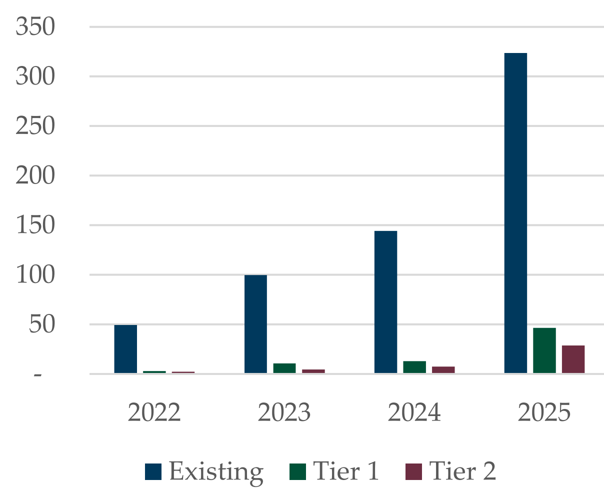


Figure 13: Demand at Risk After Imports 2022–2025 (GWh)

Long-Term Analysis (Years 5–10)

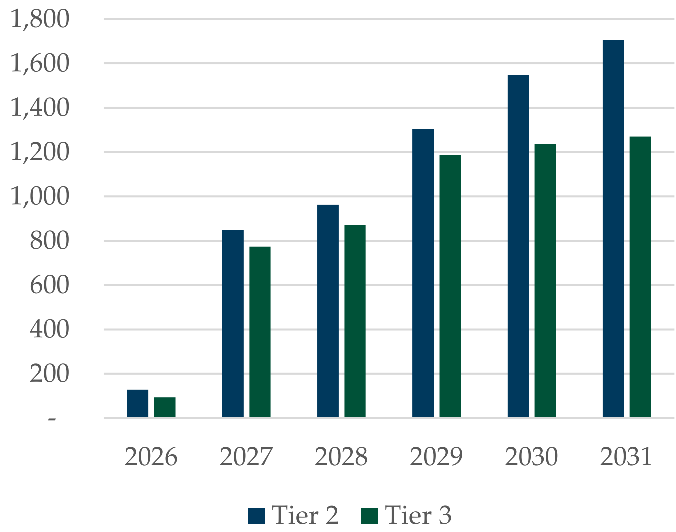


Figure 15: Demand at Risk After Imports 2026–2031 (Hours)

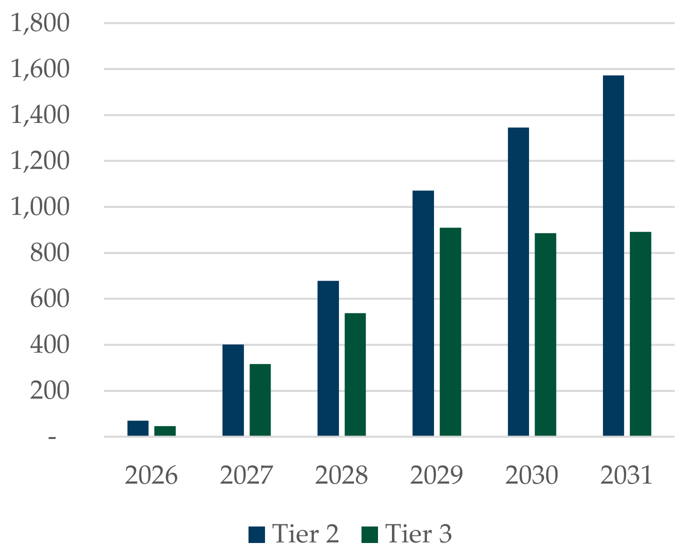


Figure 14: Demand at Risk After Imports 2026–2031 (GWh)

After Imports

Given demand and resource projections over the next 10 years, a PRM of 20.6% would achieve 99.98% reliability in 2031. However, without imports, the current resource addition plans will not achieve this PRM. Even with all planned Tier 1, 2, and 3 additions in service and imports, the NWPP-NE subregion has hours at risk each year from 2026 through 2031. With all Tier 2 resources built, the subregion still has 1,705 hours and 1,573 GWh of demand at risk in 2031. Even with all Tier 3 resources the subregion still has 1,270 hours and 892 GWh of demand at risk in 2031.

Chapter 4

Supplemental Subregion Results

Northwest Power Pool—Central

Subregion Results—NWPP-C

This assessment uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances where there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level (See Chapter 1) and within each of the five subregions:

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

This section focuses on the NWPP-C subregion, a summer peaking area that includes all of Utah and Colorado, most of Nevada, and parts of Idaho and Wyoming.

The results cover three areas of the probabilistic assessment:

1. Variability
2. Demand at Risk
3. Imports

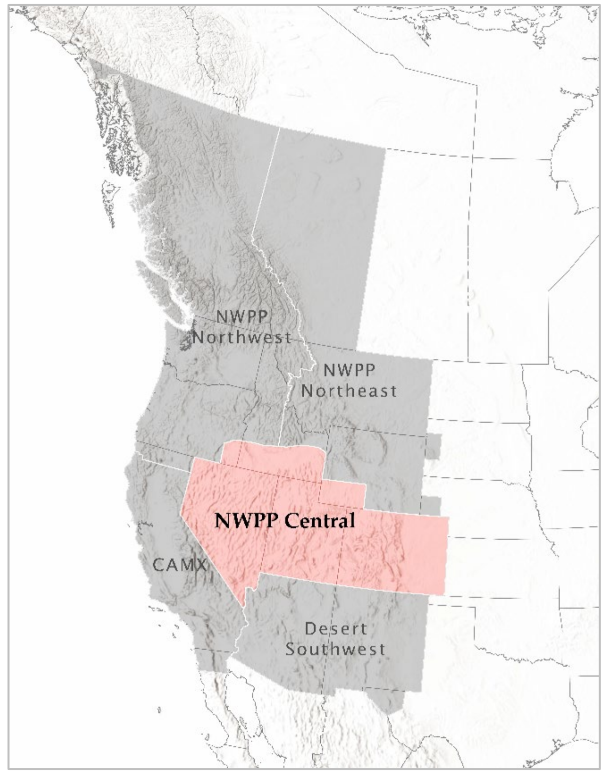


Figure 1: NWPP-C Subregion Map

Variability

The Western Assessment analyzes both demand and resource variability. For a broader discussion of variability in the Western Interconnection, see Chapter 2.

Demand Variability

Extreme weather is a significant driver of demand variability. This section provides information on demand expectations in the near-term and potential demand variability over the next 10 years.

E In 2022, the expected peak demand for the NWPP-C subregion is 36,812 MW.

33% There is a 1-in-3 probability (33%) that the demand could increase to 38,100 MW, a 3% increase.

3% There is a 1-in-33 probability (3%) the peak demand could reach 43,434 MW. This is a change of more than 18% from expected demand levels.

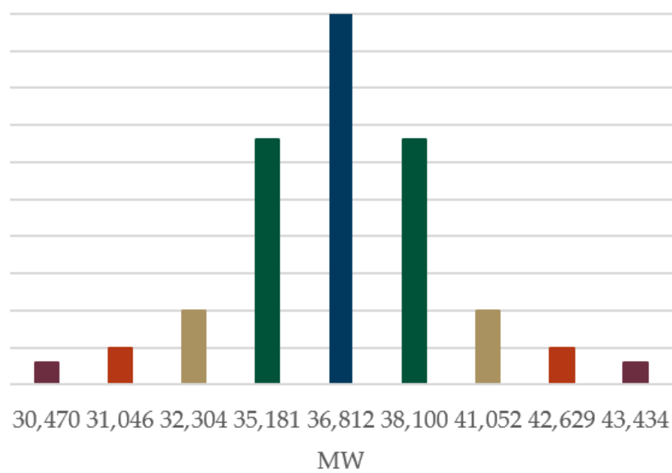


Figure 2: **NWPP-C 2022 Peak Hour Demand Variability**

Figure 3 shows the probability curves for each of the next 10 years, assuming no major changes in the variability of demand, such as extreme weather events. Given the rapid and unpredictable changes occurring on the system, the variability of demand is likely to increase beyond what the figure shows over the next 10 years.

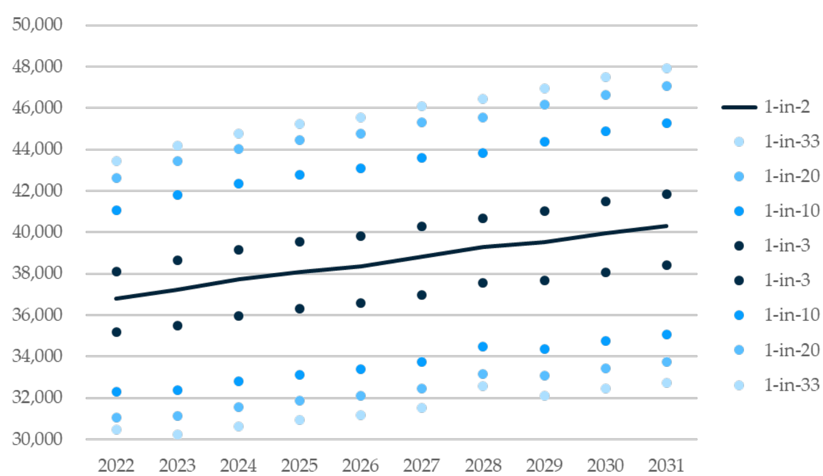


Figure 3: **Peak Demand Variability in NWPP-C Subregion 2022–2031**

Resource Availability

The NWPP-C subregion is a baseload-heavy subregion with 63% of its resource capacity being coal or natural gas. Based on current projections, that portion will drop to less than 50% by 2031.

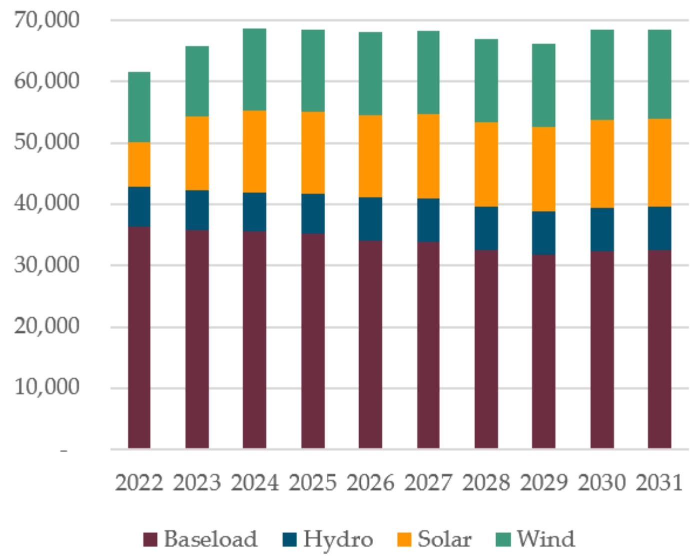


Figure 4: NWPP-C Expected Generation Mix 2022–2031

In 2022, the NWPP-C will have 36,400 MW of baseload capacity in service. This will decrease by almost 4,000 MW by 2031.

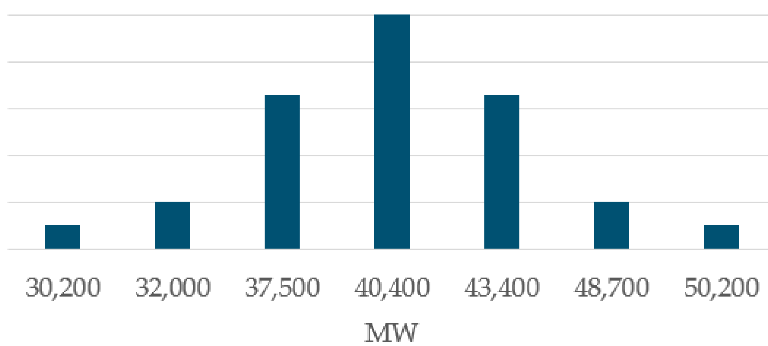
Hydro resources in the NWPP-C subregion are projected to increase slightly from 6,400 to 7,100 MW over the next 10 years.

Wind resources are forecast for 11,400 MW in 2022, with another 3,000 MW planned by 2031.

Solar resources will almost double in the next decade from 7,400 to 14,300 MW.

Of the more than 61,000 MW of nameplate capacity, the NWPP-C subregion is expected to have 40,400 MW of available generation during its peak hour in 2022.

Low resource availability caused by a 1-in-20 weather event could reduce this to 30,200 MW. In this scenario, with an expected peak demand of 36,812 MW, the NWPP-C would need to rely on imports to be resource adequate.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	25,000	26,000	28,500	29,400	30,400	31,700	31,900
Hydro	2,400	2,700	3,600	4,400	4,900	5,400	5,500
Solar	2,700	3,000	4,400	4,700	5,000	5,300	5,400
Wind	100	300	1,000	1,900	3,100	6,300	7,400

Figure 5: 2022 Peak Hour Resource Variability

Demand at Risk

When, during a given hour, the reliability threshold (99.98%) cannot be maintained, that hour is called an hour at risk because it has a greater than acceptable risk for load loss. Increasing or decreasing the PRM will affect the number of hours at risk. This part of the assessment compares the number of hours at risk for three PRMs:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Applied to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach.

In 2022, the Peak Demand PRM (14%) results in 524 hours in which demand is at risk of not being served. Most of these hours at risk occur from March through June. The hour with the greatest risk is in mid-June, with 1,500 MW at risk.

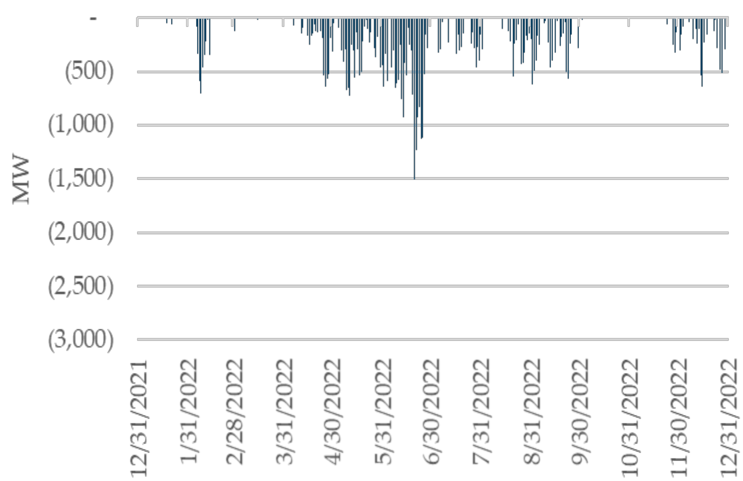


Figure 6: NWPP-C 2022 Demand at Risk—Peak Demand PRM (14%)

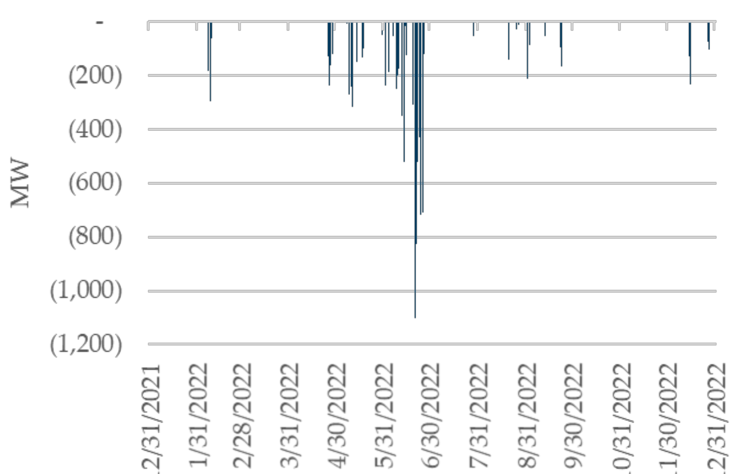
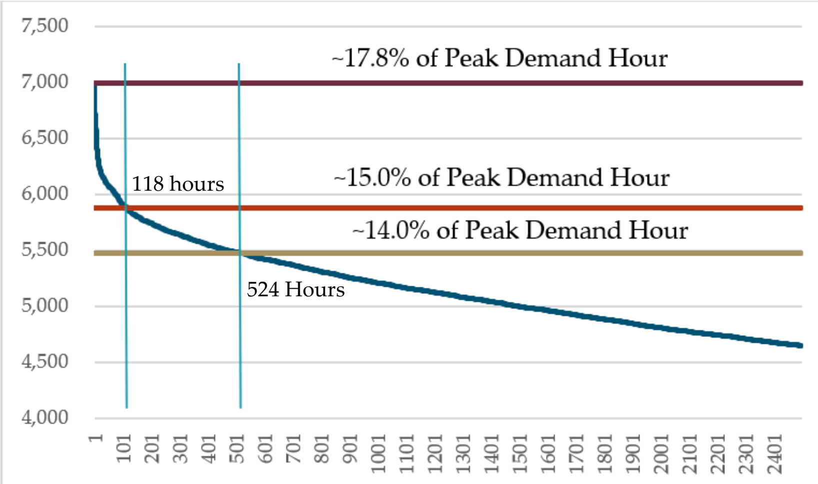


Figure 7: NWPP-C 2022 Demand at Risk—Fixed PRM (15%)

Using the Fixed PRM (15%) reduces the number of hours at risk to 118. Most of the hours at risk are in the spring. The hour with the greatest amount of risk is in June, with 1,100 MW at risk.



With a Peak Hour PRM (14%), the NWPP-C subregion has 524 hours at risk in 2022.

The Fixed PRM reduced the number of hours in which demand is at risk to 118.

In 2022, a 17.8% PRM (6,989 MW) will allow the NWPP-C subregion to reduce hours at risk for load loss enough to remain 99.98% reliable. This number is expected to increase to 20.3% (8,257 MW) by 2025.

Figure 8: NWPP-C 2022 Demand at Risk with Different PRMs

Years	Peak Demand (MW)	Total Reliability PRM (%)	Total Reliability PRM (MW)
2022	39,162	17.8%	6,989
2023	39,668	17.7%	7,026
2024	40,235	20.1%	8,083
2025	40,663	20.3%	8,257
2026	41,000	20.1%	8,257
2027	41,496	19.9%	8,248
2028	42,049	19.9%	8,381
2029	42,346	19.7%	8,349
2030	42,834	20.6%	8,833
2031	43,260	20.4%	8,842

Imports

This section evaluates imports by examining two scenarios, each comprising three variations (See Figure 9). Each hour over near-term (years 1–4) and long-term (years 5–10) is examined to determine whether the subregion has hours at risk of load loss. For a discussion of the role of imports in resource adequacy, see Chapter 2.

Scenario 1 determines whether a subregion can be resource adequate without importing energy. In Scenario 2, imports are allowed. For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by Balancing Authorities (BA) in their data submissions are the same in all three variations.

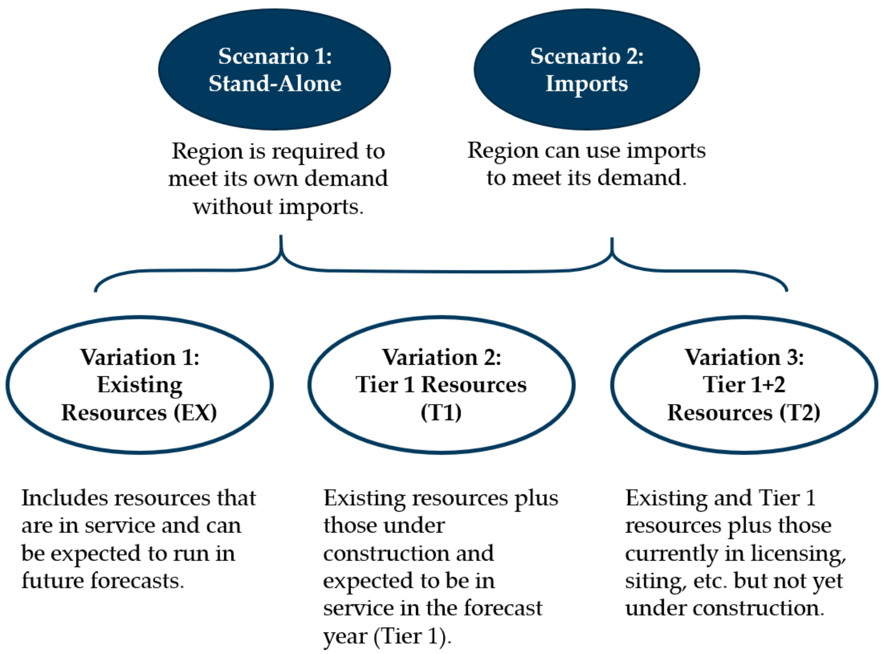
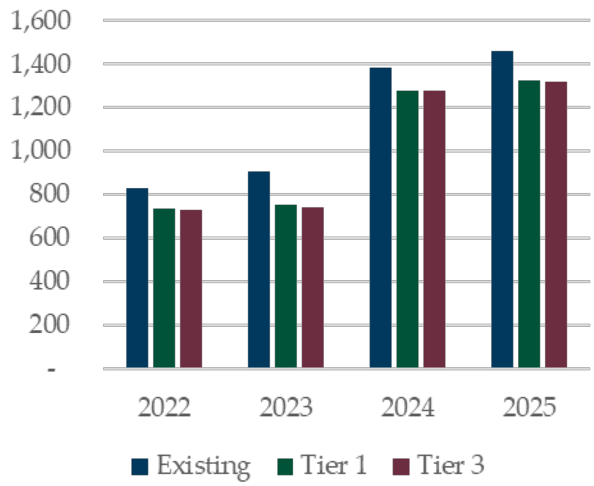


Figure 9: Western Assessment Scenarios and Variations

Near-Term Analysis (Years 1–4)

Figure 10: Demand at Risk Before Imports 2022–2025 (Hours)



Before Imports

In 2022, without imports, the NWPP-C subregion has 731 hours of demand at risk, meaning the subregion is not 99.98% reliable. This is a potential 1,271 GWh of unserved energy. This increases to 1,319 hours and 3,028 GWh by 2025 (Figures 10 and 12).

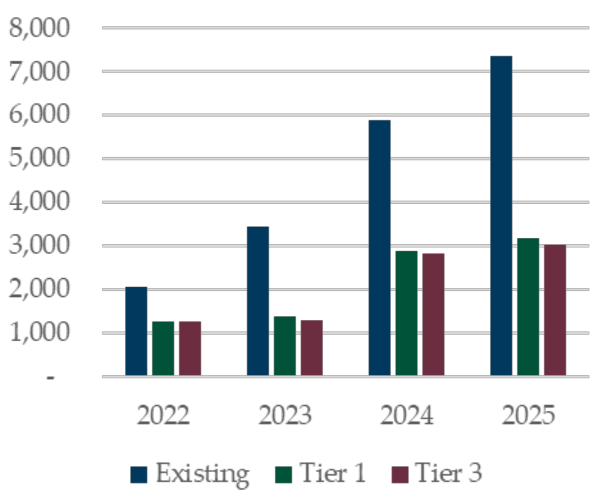
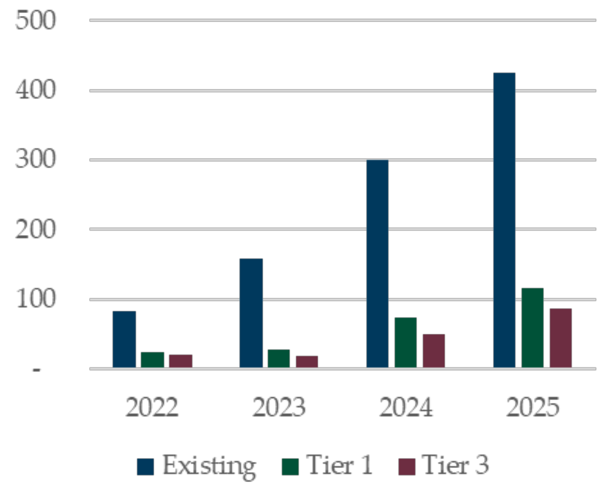


Figure 12: Demand at Risk Before Imports 2022–2025 (GWh)

Figure 11: Demand at Risk After Imports 2022–2025 (Hours)



After Imports

In 2022, with imports, the risk of unserved demand is significantly reduced to 21 hours and 5 GWh of energy. By 2025, imports help reduce the risk of unserved demand to 87 hours and about 132 GWh of energy (Figures 11 and 13).

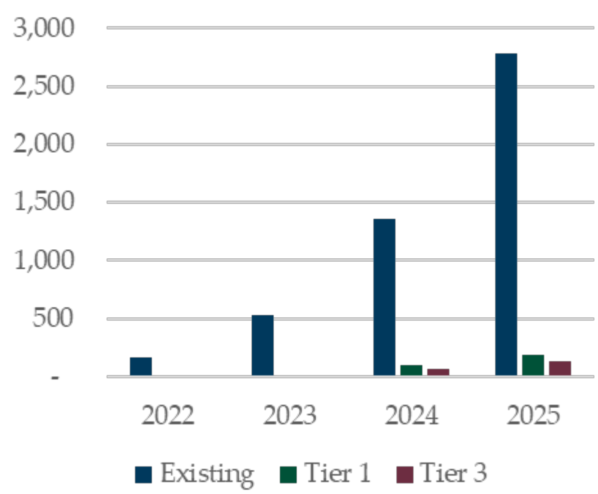


Figure 13: Demand at Risk After Imports 2022–2025 (GWh)

Long-Term Analysis (Years 5–10)

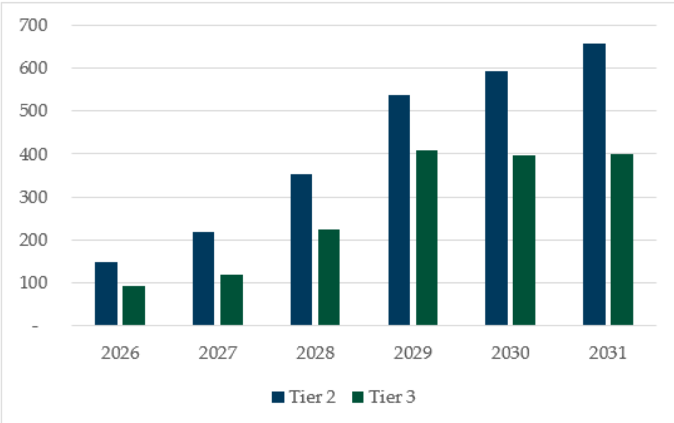


Figure 14: Demand at Risk After Imports 2026–2031 (Hours)

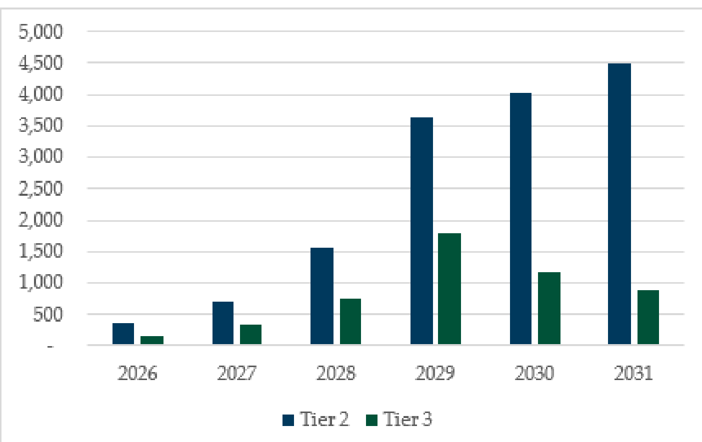


Figure 15: Demand at Risk After Imports 2026–2031 (GWh)

After Imports

Given demand and resource projections over the next 10 years, a PRM of 20.4% would achieve 99.98% reliability in 2031. However, without imports, the current resource addition plans will not achieve this PRM. Even with all planned Tier 1, 2, and 3 additions in service *and* imports, the NWPP-C subregion has hours at risk each year from 2026 through 2031. With all Tier 2 resources built, the subregion still has 656 hours and 4,498 GWh of demand at risk in 2031. Even with all Tier 3 resources, the subregion still has 400 hours and 878 GWh of demand at risk in 2031.

Chapter 4

Supplemental Subregion Results

California-Mexico

Subregion Results—CAMX

This assessment uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances where there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level (See Chapter 1) and within each of the five subregions:

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

This section focuses on the California and Mexico (CAMX) subregion, a summer-peaking area that includes most of the state of California, parts of Nevada, and Baja California, Mexico.

The results cover three areas of the probabilistic assessment:

1. Variability
2. Demand at Risk
3. Imports

Figure 1: CAMX Subregion Map

Variability

The Western Assessment analyzes both demand and resource variability. For a broader discussion of variability in the Western Interconnection, see Chapter 2.

Demand Variability

Extreme weather is a significant driver of demand variability. This section provides information on demand expectations in the near-term and potential demand variability over the next 10 years.

E In 2022, the expected peak demand for the CAMX subregion is 55,190 MW.

33% There is a 1-in-3 probability (33%) that the demand could increase to 58,554 MW, a 6% increase.

3% There is a 1-in-33 probability (3%) the peak demand could reach 68,628 MW. This is a change of over 24% from expected demand levels.

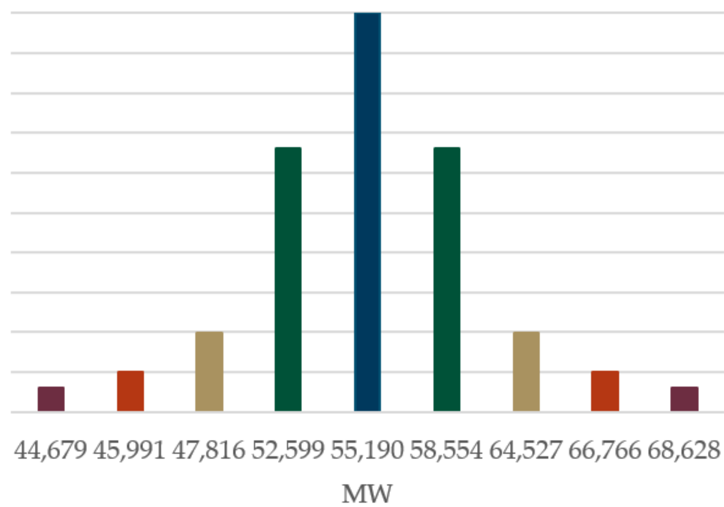


Figure 2: **CAMX 2022 Peak Hour Demand Variability**

Figure 3 shows the probability curves for each of the next 10 years, assuming no major changes in the variability of demand, such as extreme weather events. Given the rapid and unpredictable changes occurring on the system, the variability of demand is likely to increase beyond what is shown in the figure over the next 10 years.

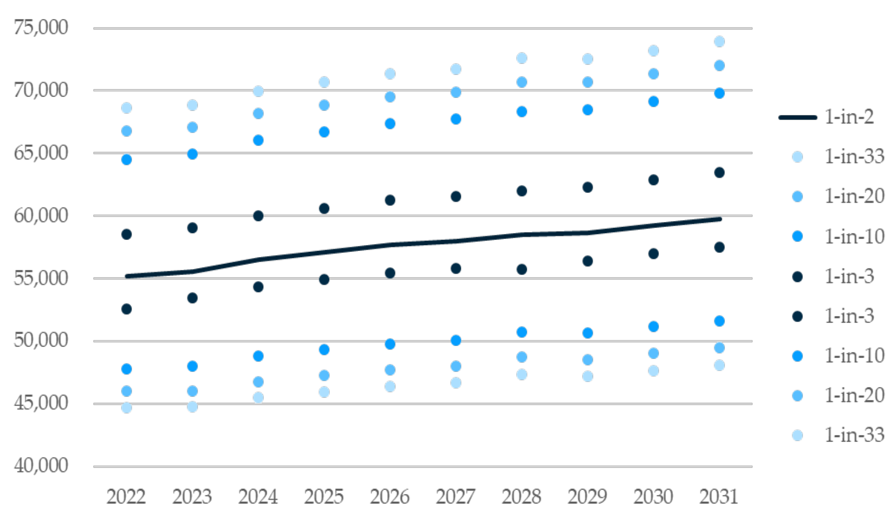


Figure 3: **Peak Demand Variability in CAMX Subregion 2022–2031**

Resource Availability

The majority of the CAMX resource portfolio is baseload generation, but by 2031, that percentage will decline.

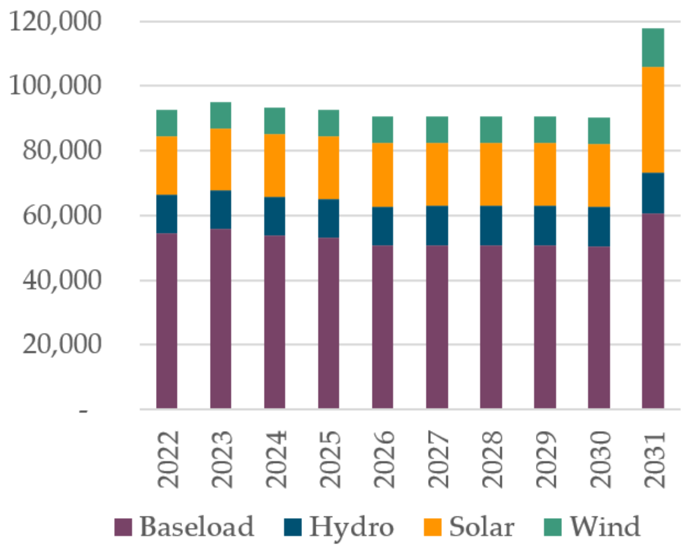


Figure 4: CAMX Expected Generation Mix 2022–2031

In 2022, the CAMX subregion will have 54,600 MW of baseload capacity in service. This will increase by 6,000 MW by 2031. Also, by 2031, CAMX is expected to have nearly 10,000 MW of battery storage.

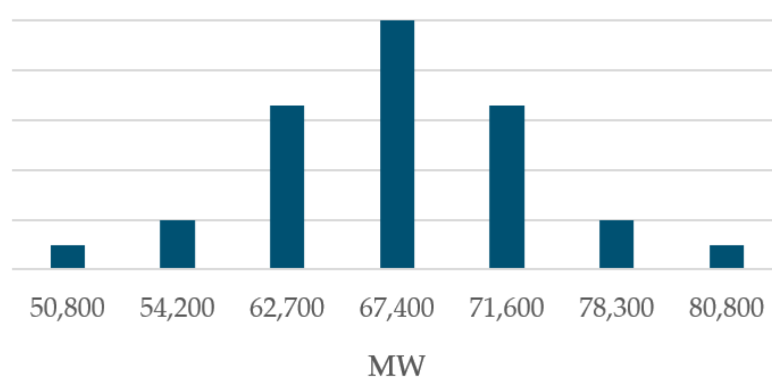
Hydro resources in CAMX are projected to remain relatively the same, growing from 12,000 to 12,600 MW by 2031.

Wind resources are forecast to grow by 50% from 8,100 MW to 12,200 MW over the next decade.

Solar resources will grow from 18,000 MW to over 32,000 MW by 2031.

Of the nearly 93,000 MW of nameplate capacity, the CAMX subregion is expected to have 67,400 MW of available generation during its peak hour in 2022.

Low resource availability caused by a 1-in-20 weather event could reduce this to 50,800 MW. In this scenario, with an expected peak demand of 55,190 MW, the CAMX subregion would need to rely on imports to be resource adequate.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	44,600	45,600	47,900	48,900	49,700	50,700	51,100
Hydro	2,200	2,400	3,800	6,000	7,100	8,100	8,600
Solar	4,000	6,100	10,400	11,400	13,000	16,300	16,800
Wind	-	100	600	1,100	1,800	3,200	4,300

Figure 5: **2022 Peak Hour Resource Variability**

Demand at Risk

When, during a given hour, the reliability threshold (99.98%) cannot be maintained, that hour is called an hour at risk because it has a greater than acceptable risk for load loss. Increasing or decreasing the PRM will affect the number of hours at risk. This part of the assessment compares the number of hours at risk for three PRMs:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Applied to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach.

In 2022, with the Fixed PRM (15%), the CAMX subregion has 359 hours in which demand is at risk of not being served. Most of these hours at risk occur between April and October.

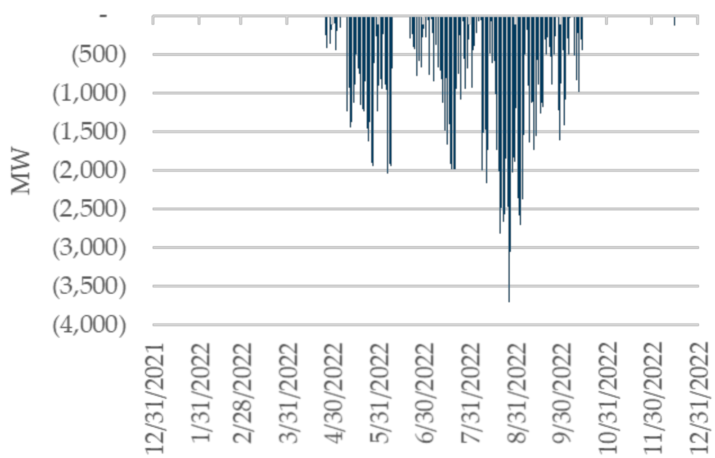


Figure 6: CAMX 2022 Demand at Risk—Fixed PRM (15%)

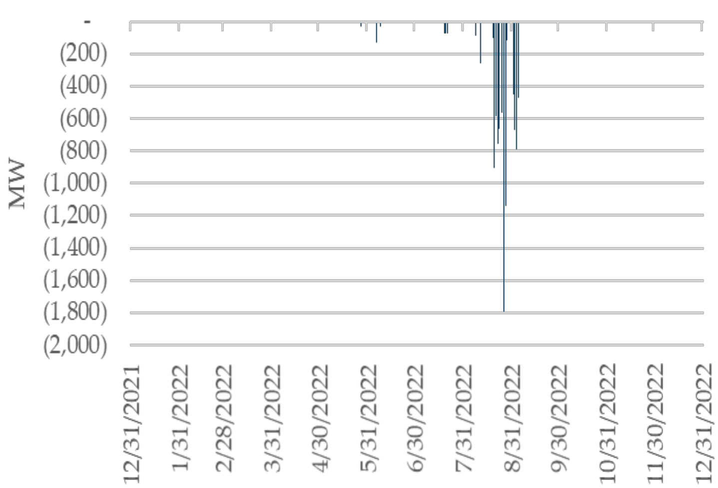
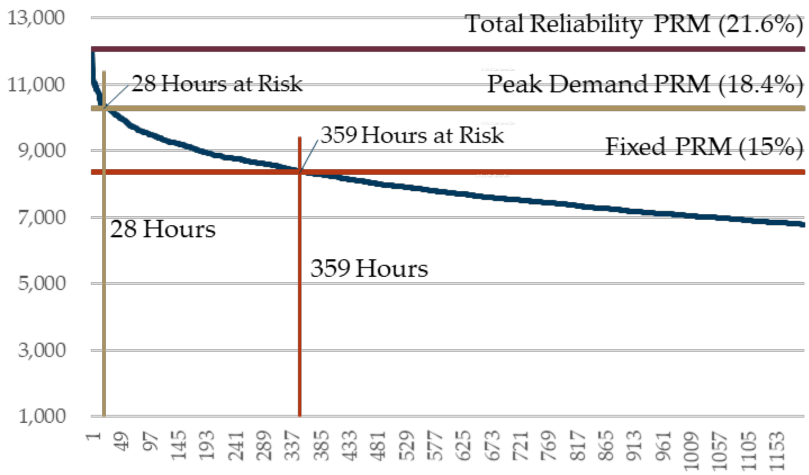


Figure 7: CAMX 2022 Demand at Risk—Peak Demand PRM (18.4%)

CAMX is the only subregion in which the Peak Demand PRM is greater than the 15% Fixed PRM. A Peak Demand PRM of 18.4% leaves 28 hours in which demand is at risk. Most of these hours are in August, with the greatest risk being 1,800 MW in late August.



The Peak Demand PRM (18.4%) reduces the number of hours in which demand is at risk to 28.

With the Fixed PRM, the CAMX subregion has 359 hours at risk in 2022.

In 2022, a Total Reliability PRM of 21.6% (12,069 MW) will achieve 99.98% reliability. This number is expected to remain stable over the next four years.

Figure 8: CAMX 2022 Demand at Risk with Different PRMs

Years	Peak Demand (MW)	Total Reliability PRM (%)	Total Reliability PRM (MW)
2022	55,790	21.6%	12,069
2023	56,186	20.6%	11,602
2024	57,123	22.0%	12,577
2025	57,693	21.8%	12,579
2026	58,278	21.6%	12,606
2027	58,591	21.5%	12,618
2028	59,115	21.3%	12,573
2029	59,271	19.8%	11,744
2030	59,833	21.3%	12,746
2031	60,405	28.1%	16,986

Imports

This section evaluates imports by examining two scenarios, each comprising three variations (See Figure 9). Each hour over near-term (years 1–4) and long-term (years 5–10) is examined to determine whether the subregion has hours at risk of load loss. For a discussion of the role of imports in resource adequacy, see Chapter 2.

Scenario 1 determines whether a subregion can be resource adequate without importing energy. In Scenario 2, imports are allowed. For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by Balancing Authorities (BA) in their data submissions are the same in all three variations.

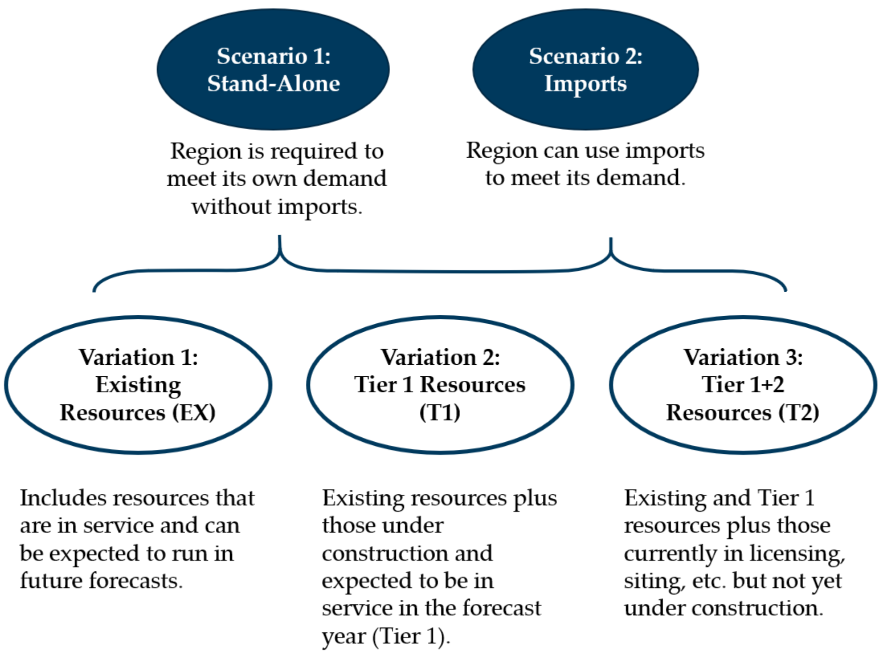
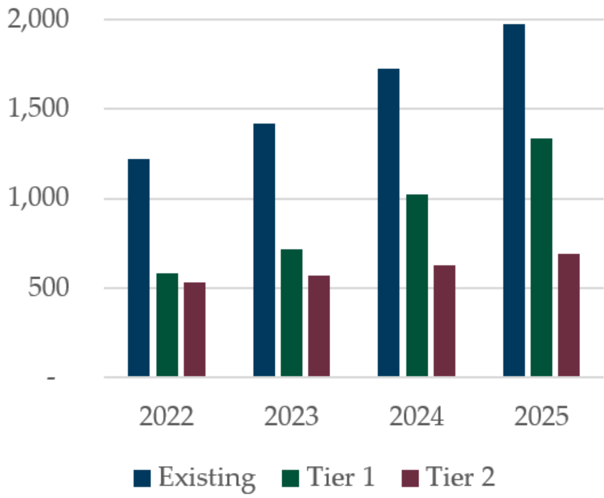


Figure 9: Western Assessment Scenarios and Variations

Near-Term Analysis (Years 1–4)

Figure 10: Demand at Risk Before Imports 2022–2025 (Hours)



Before Imports

In 2022, without imports, the CAMX subregion has 529 hours of demand at risk, meaning the subregion is not 99.98% reliable. This is equal to 336 GWh of unserved energy. This increases to 689 hours and over 1,000 GWh by 2025 (Figures 10 and 12).

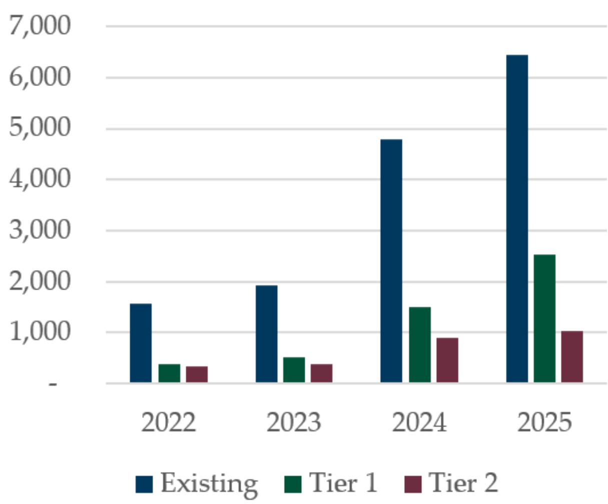
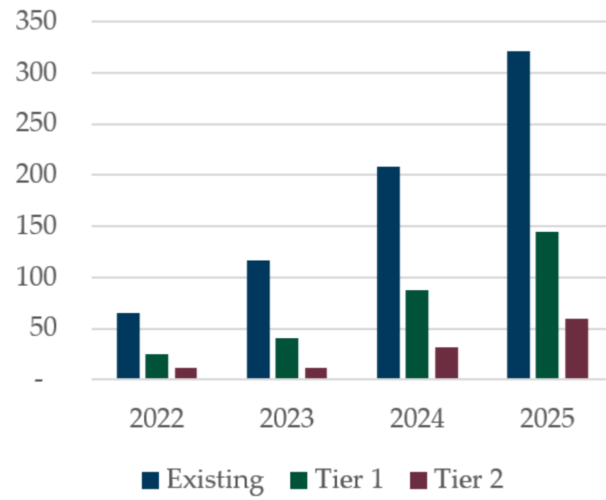


Figure 12: Demand at Risk Before Imports 2022–2025 (GWh)

Figure 11: Demand at Risk After Imports 2022–2025 (Hours)



After Imports

In 2022, with imports, the risk of unserved demand is significantly reduced to 11 hours and 6 GWh at risk. By 2025, this increases to 60 hours and 194 GWh at risk (Figures 11 and 13).

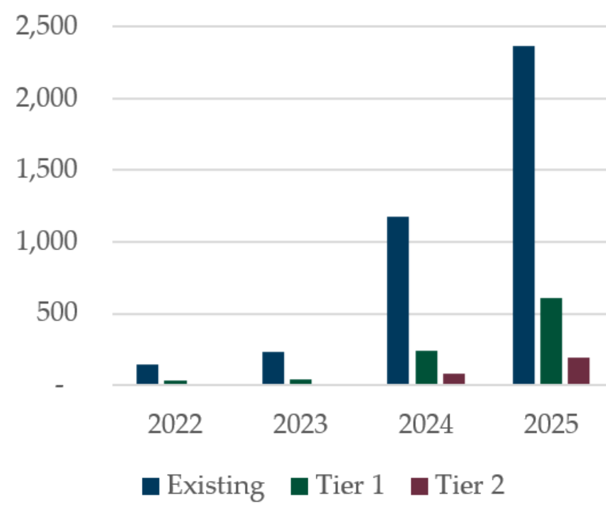


Figure 13: Demand at Risk After Imports 2022–2025 (GWh)

Long-Term Analysis (Years 5–10)

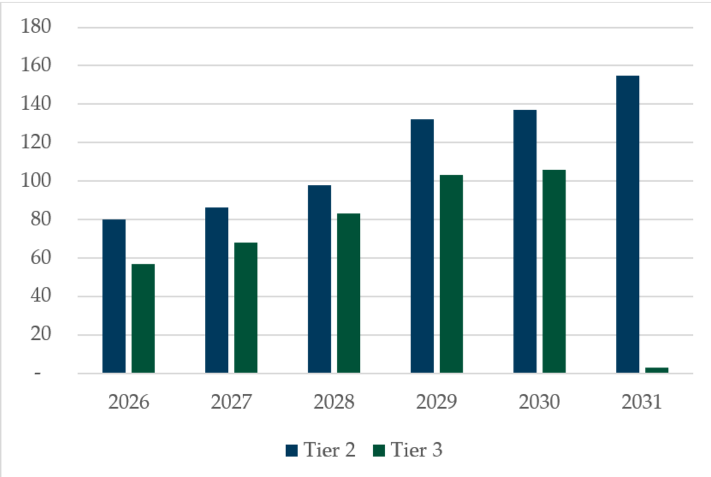


Figure 14: Demand at Risk After Imports 2026–2031 (Hours)

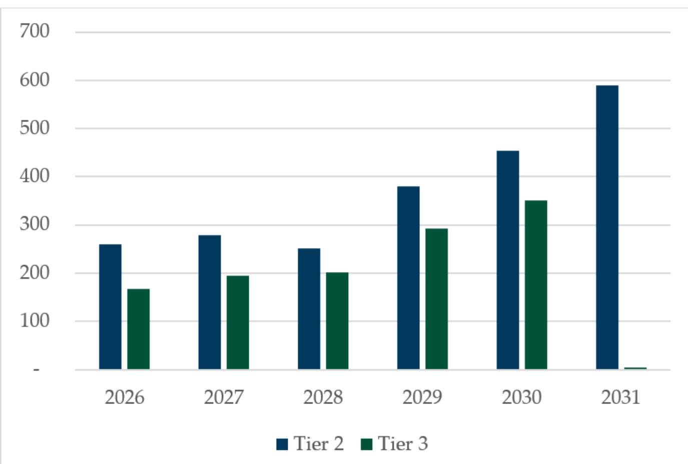


Figure 15: Demand at Risk After Imports 2026–2031 (GWh)

After Imports

Given demand and resource projections over the next 10 years, a PRM of 28.1% would achieve 99.98% reliability in 2031. However, without imports, the current resource addition plans will not achieve this PRM. Even with all planned Tier 1, 2, and 3 additions in service *and* imports, the CAMX subregion has hours at risk each year from 2026 through 2031. With all Tier 2 resources built, the subregion still has 155 hours and 589 GWh of demand at risk in 2031. With all Tier 3 resources, the subregion has 3 hours and 1 GWh of demand at risk in 2031.

Chapter 4

Supplemental Subregion Results

Desert Southwest

Subregion Results—DSW

This assessment uses an energy-based probabilistic approach. It evaluates potential demand and resource availability for each hour over the 10-year study period to identify instances where there is a risk of load loss due to a lack of resource adequacy.

The Western Assessment examines resource adequacy both at the interconnection level (See Chapter 1) and within each of the five subregions:

- Northwest Power Pool Northwest (NWPP-NW)
- NWPP Northeast (NWPP-NE)
- NWPP Central (NWPP-C)
- California-Mexico (CAMX)
- Desert Southwest (DSW)

This section focuses on the Desert Southwest (DSW) subregion, a summer-peaking area that includes all of Arizona, most of New Mexico, and parts of Texas and California (Imperial Irrigation District).

The results cover three areas of the probabilistic assessment:

1. Variability
2. Demand at Risk
3. Imports

Figure 1: DSW Subregion Map

Variability

The Western Assessment analyzes both demand and resource variability. For a broader discussion of variability in the Western Interconnection, see Chapter 2.

Demand Variability

Extreme weather is a significant driver of demand variability. This section provides information on demand expectations in the near-term and potential demand variability over the next 10 years.

E In 2022, the expected peak demand for the DSW subregion is 25,203 MW.

33% There is a 1-in-3 probability (33%) that the demand could increase to 26,108 MW, a 4% increase.

3% There is a 1-in-33 probability (3%) the peak demand could reach 28,736 MW. This is a change of over 14% from expected demand levels.

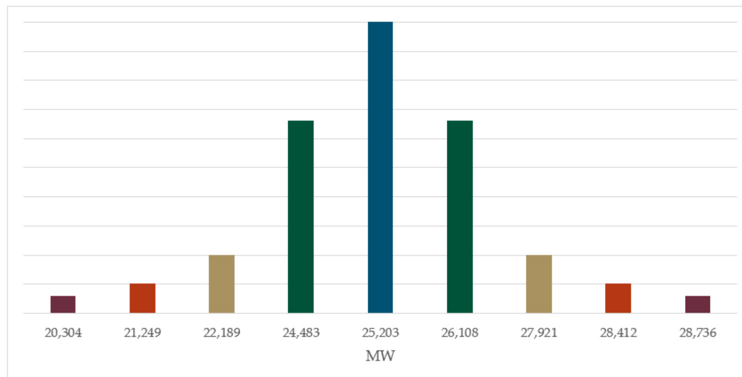


Figure 2: **DSW 2022 Peak Hour Demand Variability**

Figure 3 shows the probability curves for each of the next 10 years, assuming no major changes in the variability of demand, such as extreme weather events. Given the rapid and unpredictable changes occurring on the system, the variability of demand is likely to increase beyond what is shown in the figure over the next 10 years.

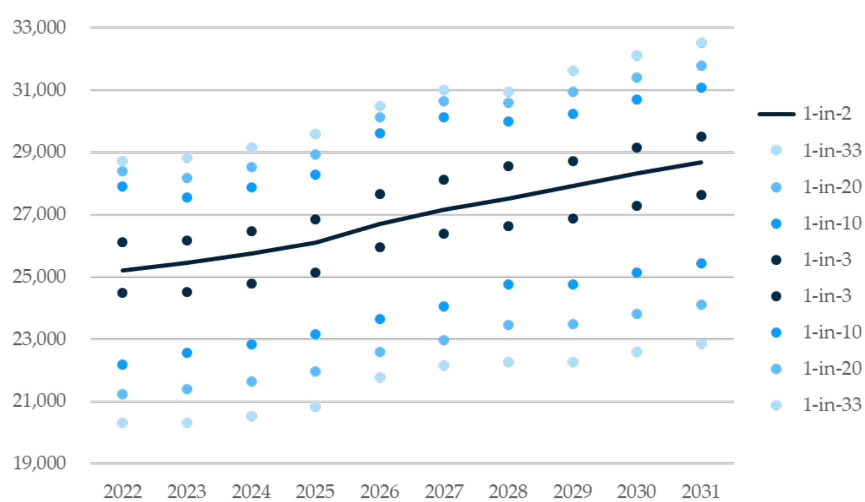


Figure 3: **Peak Demand Variability in DSW Subregion 2022–2031**

Resource Availability

The DSW subregion's resource portfolio is over 80% baseload from nuclear, coal, and natural gas. Baseload capacity will remain roughly the same through 2031, but its portion of the portfolio will decrease.

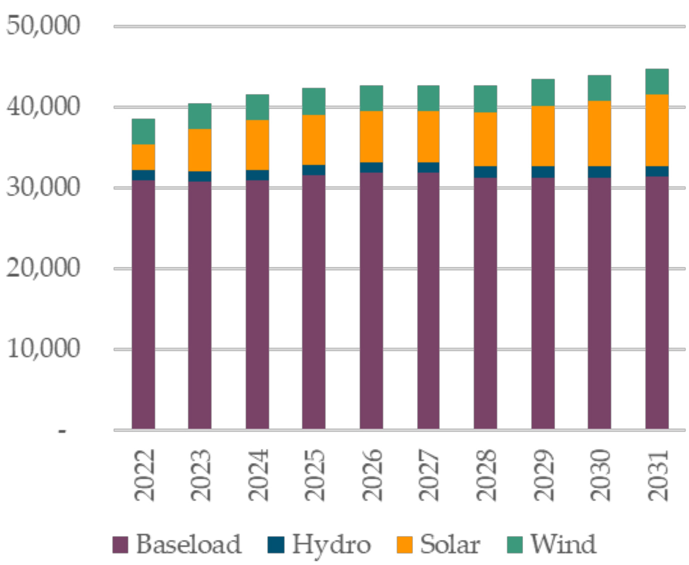


Figure 4: DSW Expected Generation Mix 2022–2031

In 2022, the DSW will have 30,900 MW of baseload capacity in service. This will increase slightly to 31,400 MW by 2031.

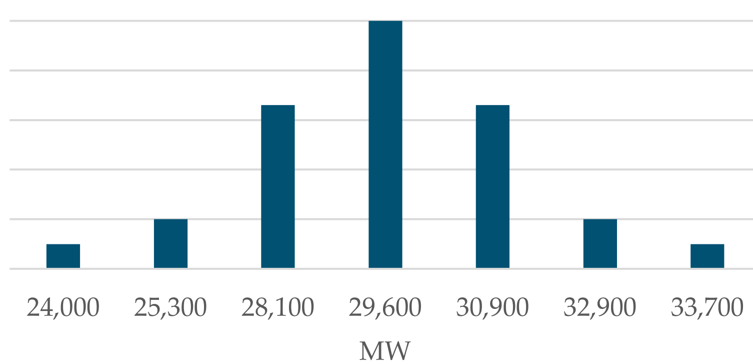
Hydro resources in the DSW are projected to remain at 1,300 MW. However, drought conditions could decrease this number significantly.

Wind resources are forecast to grow over the next decade and will remain at 3,200 MW.

Solar resources will more than double in the next decade from 3,200 to 8,800 MW.

Of the almost 39,000 MW of nameplate capacity, the DSW subregion is expected to have 29,600 MW of available generation during its peak hour in 2022.

Low resource availability caused by a 1-in-20 weather event could reduce this to 21,800 MW. In this scenario, with an expected peak demand of 25,203 MW, the DSW would need to rely on imports to be resource adequate.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	21,800	22,400	24,100	24,900	25,700	26,600	26,900
Hydro	1,500	1,500	1,800	1,900	2,000	2,200	2,300
Solar	700	1,300	1,800	2,200	2,400	2,700	2,800
Wind	-	100	400	600	800	1,400	1,700

Figure 5: **2022 Peak Hour Resource Variability**

Demand at Risk

When, during a given hour, the reliability threshold (99.98%) cannot be maintained, that hour is called an hour at risk because it has a greater than acceptable risk for load loss. Increasing or decreasing the PRM will affect the number of hours at risk. This part of the assessment compares the number of hours at risk for three PRMs:

- **Peak Demand PRM**: The PRM needed to ensure the peak demand hour each year is 99.98% reliable. Applied to all hours of the year.
- **Fixed PRM**: A 15% PRM applied to all hours, representing a "default" PRM sometimes used by industry.
- **Total Reliability PRM**: The PRM needed to account for the demand and resource variability and ensure all hours of the year are 99.98% reliable. Calculated independently for each hour using the probabilistic, energy-based approach.

In 2022, the Peak Demand PRM (12.5%) results in 134 hours in which demand is at risk of not being served. Most of these hours at risk occur between April and October. The hour with the greatest risk is in October, with over 600 MW at risk.

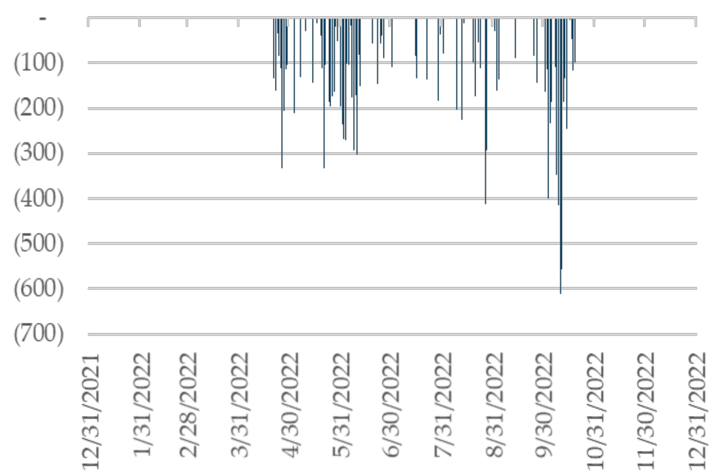


Figure 6: DSW 2022 Demand at Risk—Peak Demand PRM (12.5%)

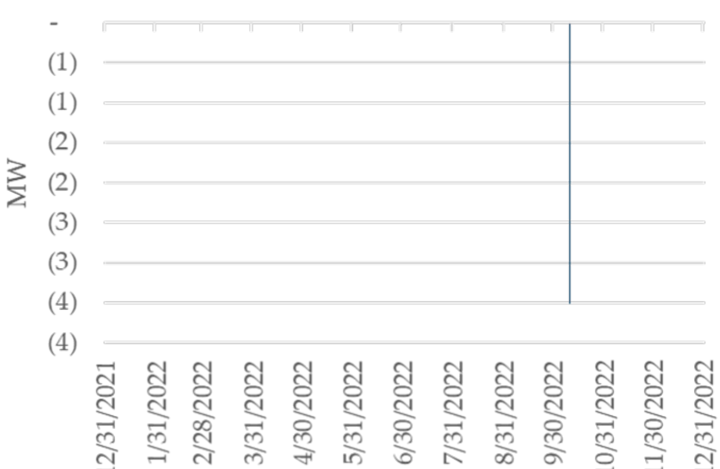
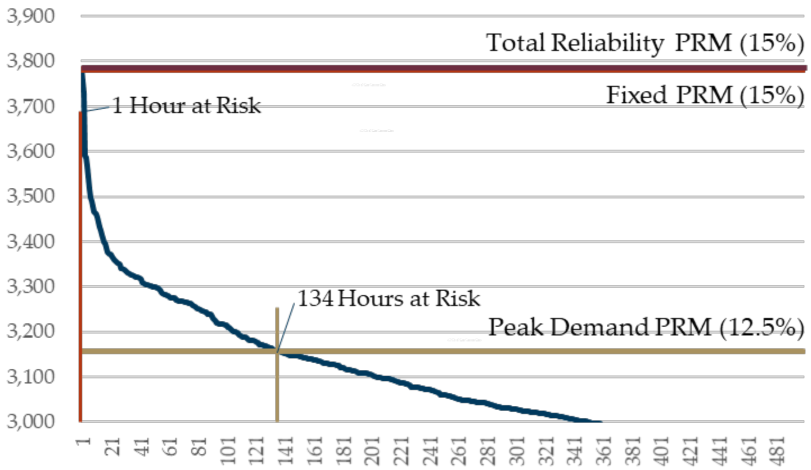


Figure 7: DSW 2022 Demand at Risk—Fixed PRM (15%)

Using the Fixed PRM (15%) reduces the number of hours at risk to 1 hour in October and has only 4 MW of demand at risk.



With a Peak Hour PRM (12.5%), the DSW subregion has 134 hours at risk in 2022.

The Fixed PRM reduced the number of hours in which demand is at risk to 1, making the subregion 99.98% reliable.

In 2022, the Total Reliability PRM is the same as the Fixed PRM, 15% (3,784 MW). However, the Total Reliability PRM is expected to increase to 18.5% (4,825 MW) by 2025.

Figure 8: DSW 2022 Demand at Risk with Different PRMs

Years	Peak Demand (MW)	Total Reliability PRM (%)	Total Reliability PRM (MW)
2022	25,203	15.0%	3,784
2023	25,445	17.7%	4,494
2024	25,742	18.7%	4,813
2025	26,113	18.5%	4,825
2026	26,690	18.3%	4,894
2027	27,155	18.2%	4,938
2028	27,512	18.2%	5,014
2029	27,920	19.1%	5,344
2030	28,340	18.7%	5,313
2031	28,684	19.3%	5,523

Imports

This section evaluates the role of imports by examining two scenarios, each comprising three variations (See Figure 9). Each hour over near-term (years 1–4) and long-term (years 5–10) is examined to determine whether the subregion has hours at risk of load loss. For a discussion of the role of imports in resource adequacy, see Chapter 2.

Scenario 1 determines whether a subregion can be resource adequate without importing energy. In Scenario 2, imports are allowed. For each scenario, there are three variations that cover the range of future resource possibilities, including known and expected resource additions. Resource retirements provided by Balancing Authorities (BA) in their data submissions are the same in all three variations.

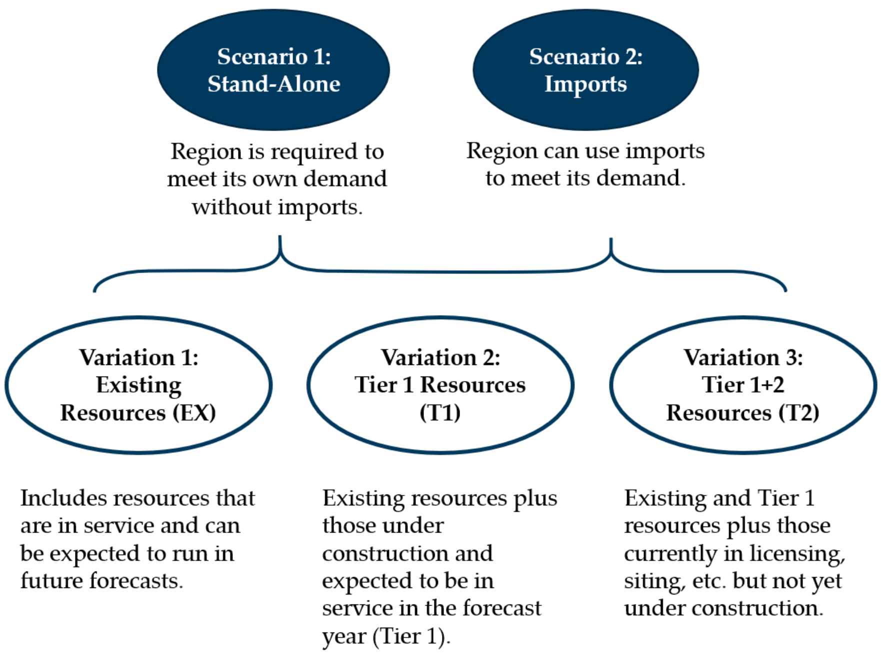


Figure 9: Western Assessment Scenarios and Variations

Near-Term Analysis (Years 1–4)

Figure 10: Demand at Risk Before Imports 2022–2025 (Hours)

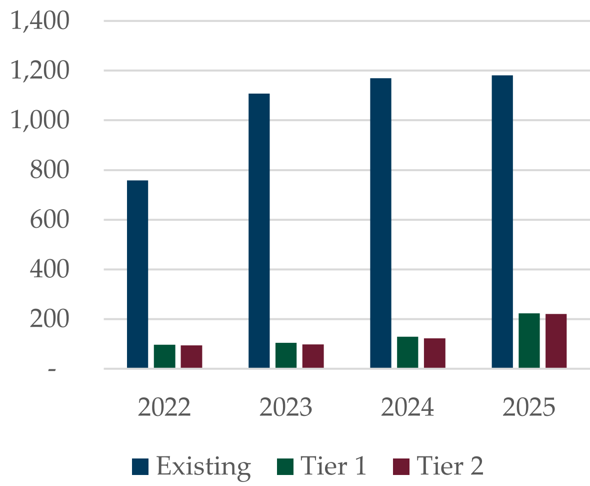
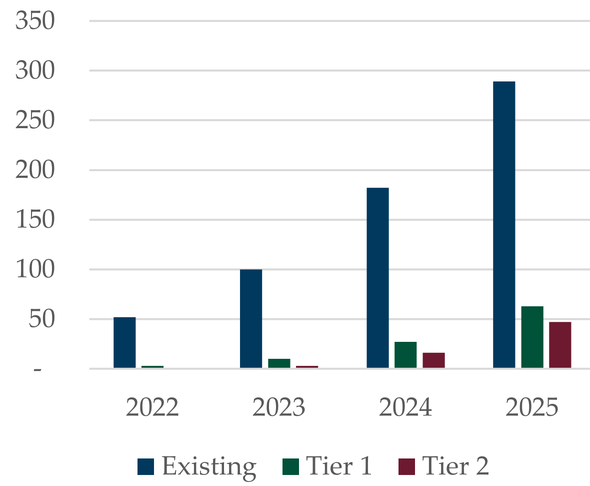


Figure 11: Demand at Risk After Imports 2022–2025 (Hours)



Before Imports

In 2022, without imports, the DSW subregion has 100 hours of demand at risk, meaning the subregion is not 99.98% reliable. However, the unserved energy is close to 0 GWh. This increases to 200 hours and 101 GWh by 2025. (Figures 10 and 12).

After Imports

In 2022, with imports, the risk of unserved demand is significantly reduced to near zero for both hours and energy at risk. By 2025, this increases to 47 hours and 15 GWh at risk. (Figures 11 and 13).

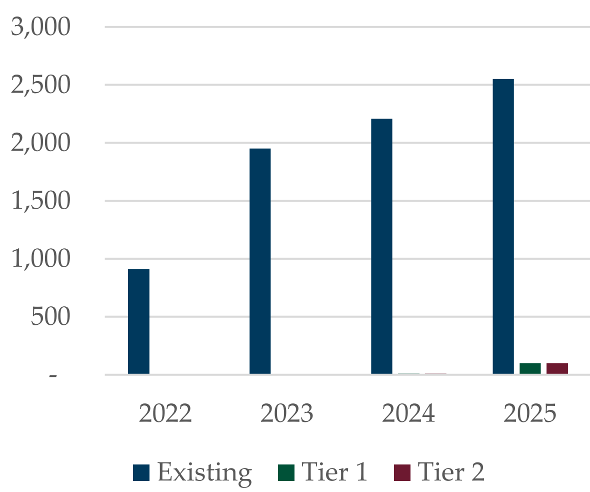


Figure 12: Demand at Risk Before Imports 2022–2025 (GWh)

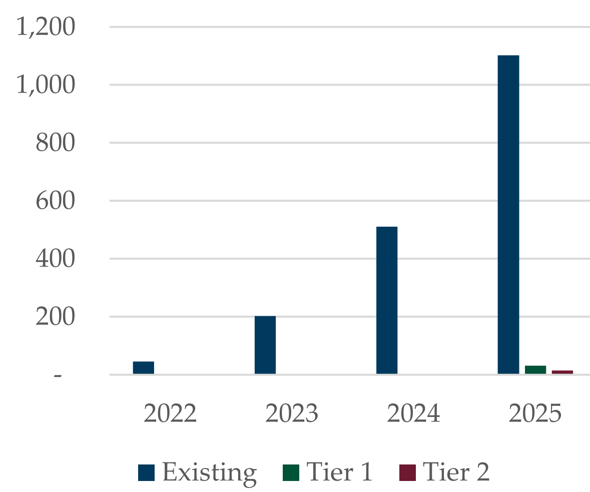


Figure 13: Demand at Risk After Imports 2022–2025 (GWh)

Long-Term Analysis (Years 5–10)

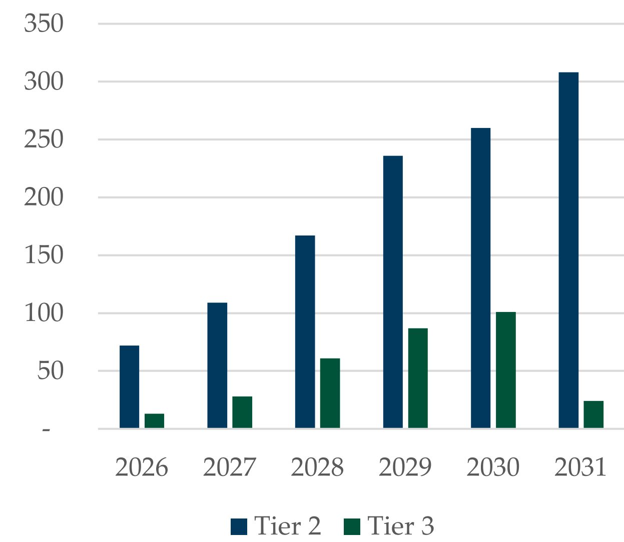


Figure 14: Demand at Risk After Imports 2026–2031 (Hours)

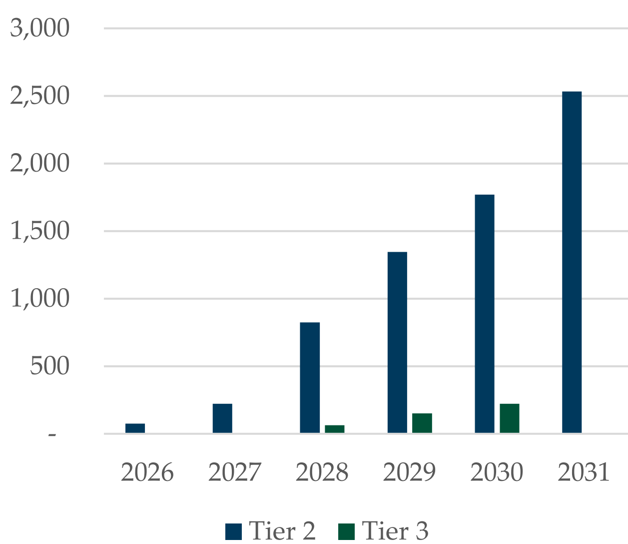


Figure 15: Demand at Risk After Imports 2026–2031 (GWh)

After Imports

Given demand and resource projections over the next 10 years, a PRM of 19.3% would achieve 99.98% reliability in 2031. However, without imports, the current resource addition plans will not achieve this PRM. Even with all planned Tier 1, 2, and 3 additions in service *and* imports, the DSW subregion has hours at risk each year from 2026 through 2031. With all Tier 2 resources built, the subregion still has 308 hours and 2,533 GWh of demand at risk in 2031. Even with all Tier 3 resources, the subregion still has 24 hours and 6 GWh of demand at risk in 2031.

Appendices

Appendix A: Methods and Process

Probabilistic Analysis

The Western Assessment uses an energy-based probabilistic analysis of resource adequacy across the entire Western Interconnection, at an hourly level, for the next 10 years. The Western Assessment was developed based on data collected from Balancing Authorities (BA) describing their demand and resource projections for that period. WECC inputs this data into its Multi-area Variable Resource Integration Convolution (MAVRIC) model to conduct the probabilistic analysis. The MAVRIC model balances the system (matching generation to load) for each hour of the study period to calculate a planning reserve margin. Then the model balances the system to the expected demand. The model determines whether there are enough resources in the interconnection to meet expected demand while maintaining reserves to account for any variations from the expected forecasts or loss of generation. The results from this analysis are used to determine where resource shortfalls may occur in the system over any given study period. For more information on the probabilistic analysis, see the 2020 Western Assessment of Resource Adequacy.

Deterministic Analysis

This report's operational scenario analysis was done using deterministic analysis through a production cost model. Deterministic analysis involves using known, fixed parameters as production cost model inputs. These parameters are the demand forecast and resource list used by MAVRIC, so the models are using consistent data and forecast assumptions. The production cost model then uses generation resources to meet load by least-cost dispatch. WECC uses Hitachi Energy's GridView for production cost modeling. GridView is also used for making the Anchor Data Set (ADS) and for the Study Program. For more information about GridView and how it is used in these contexts, visit the ADS Data Development and Validation Manual and the WECC 2038 Scenarios Reliability Assessment.

Appendix B: Resource Data Inputs

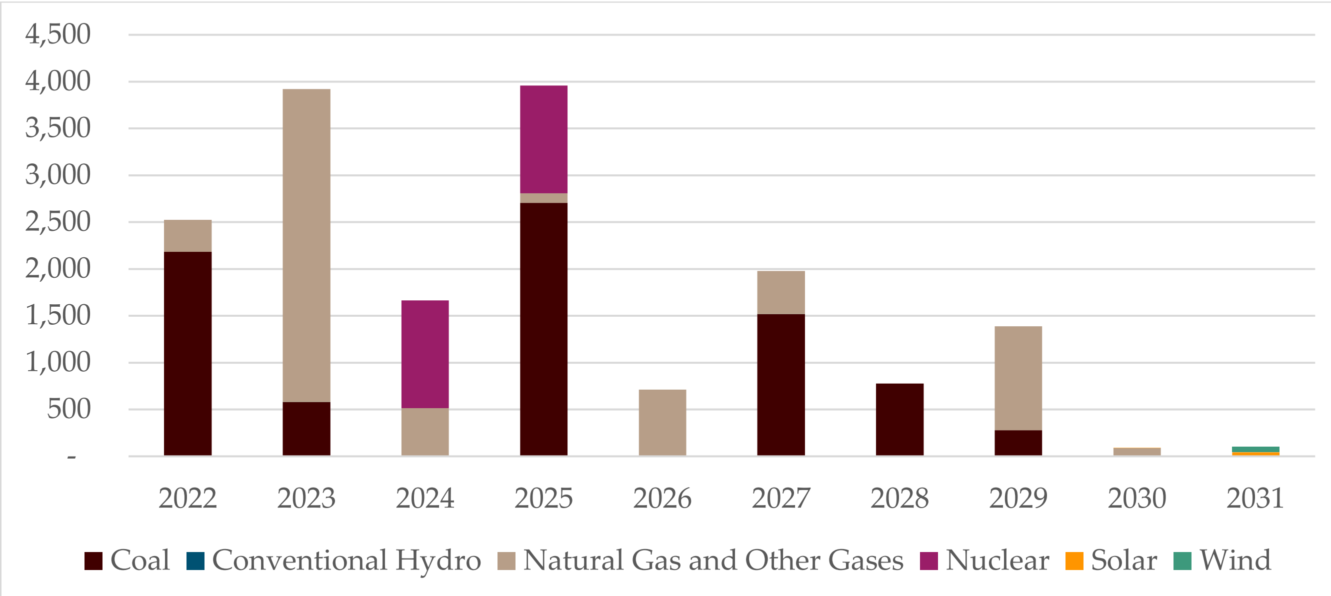
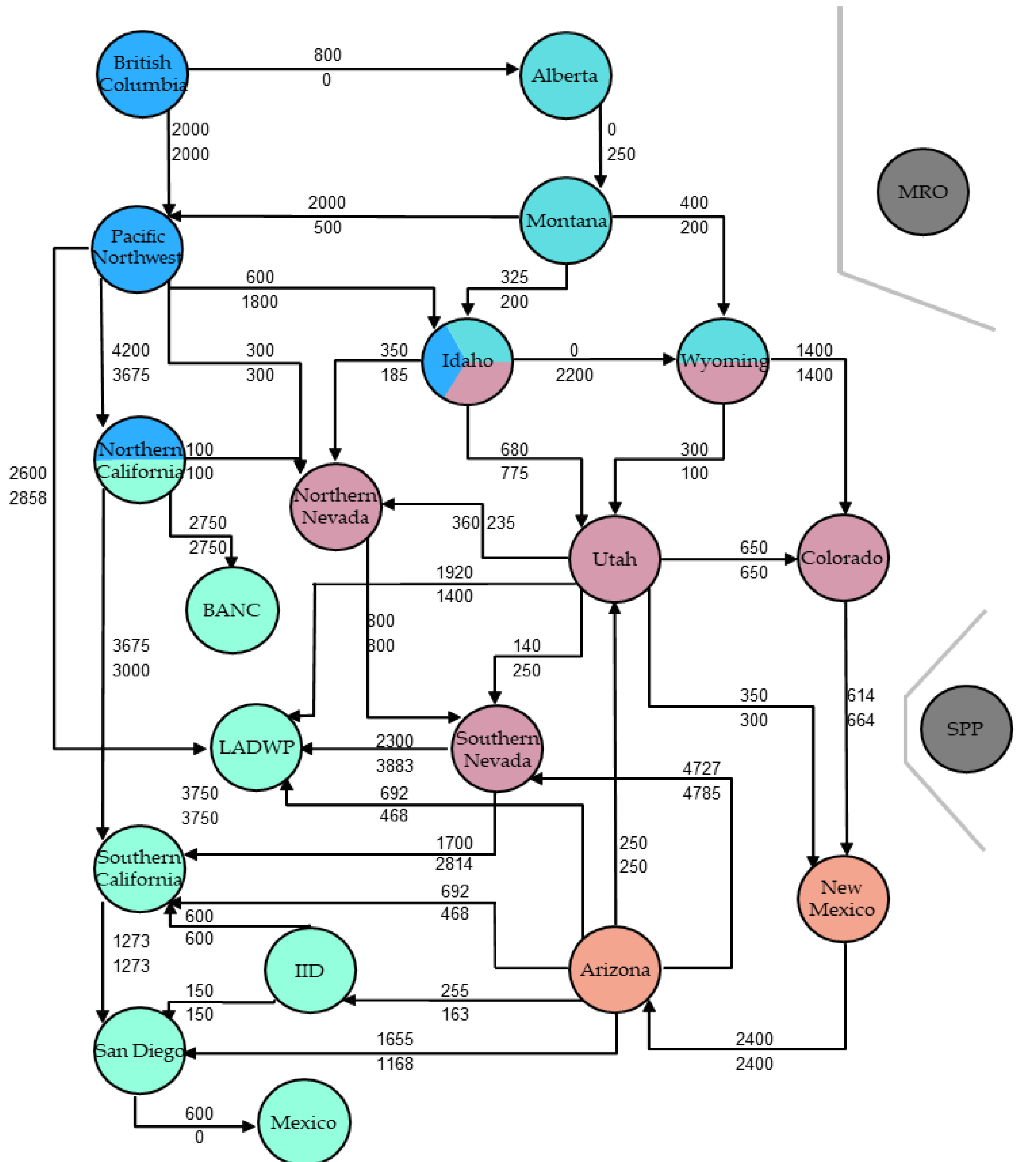


Figure 1: Western Interconnection Capacity Retired by Resource Type 2022–2031

Retirements, Additions, and Conversions Tables

WECC uses information on resource retirements, additions, and conversions submitted by BA in their annual loads and resources data submittals. From there, WECC updates retirement information using various sources. See the WECC 2021 Resource List.

Appendix C: Transmission Topology Maps

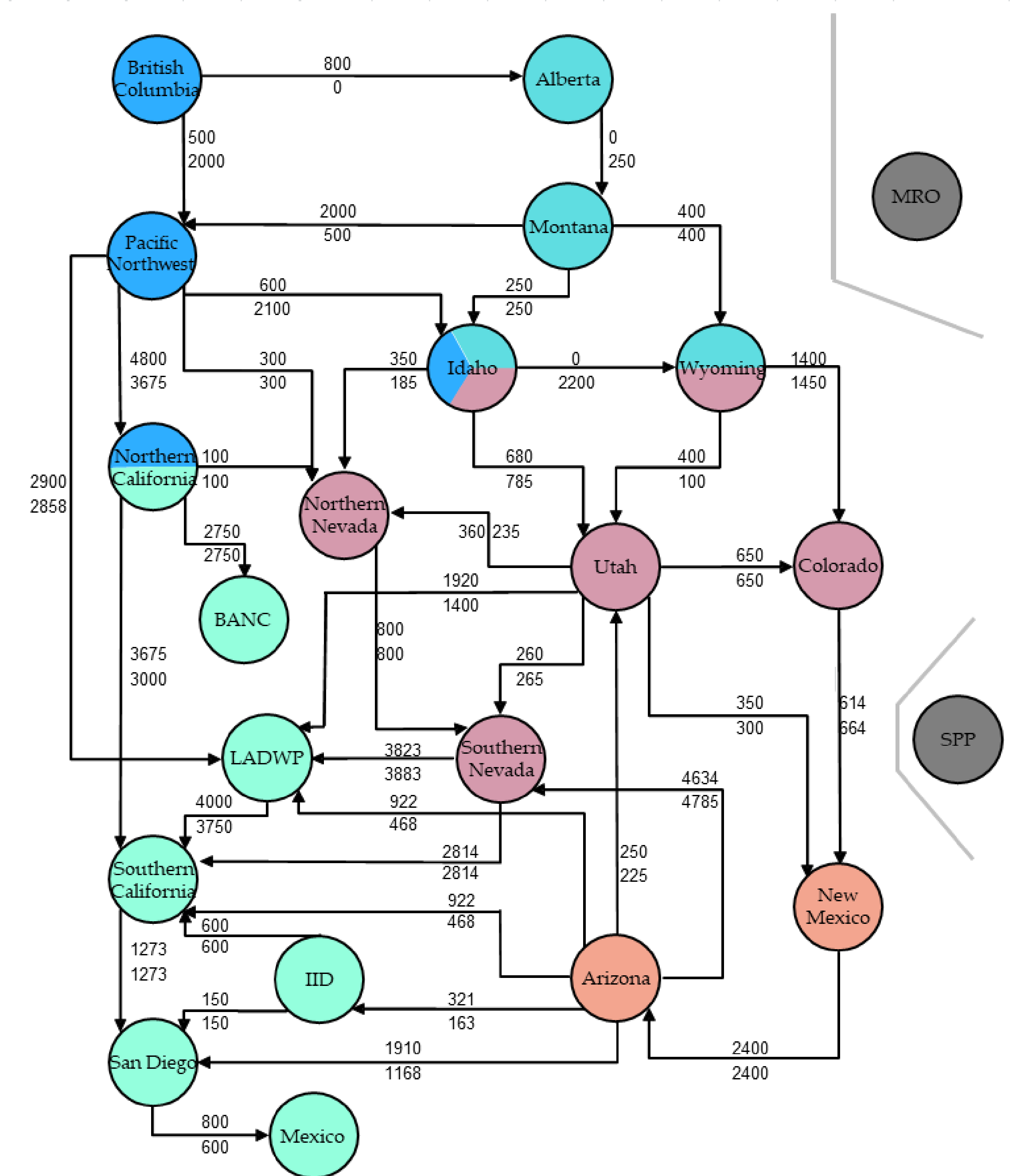


Legend

For each pair of numbers, the top or left number is the transfer capability (MW) in the direction of the arrow. The bottom or right number is the transfer capability in the opposite direction of the arrow.

NWPP-NW CAMX NWPP-NE NWPP-C DSW

Figure 2: Summer Zonal Topology Diagram



Legend

For each pair of numbers, the top or left number is the transfer capability (MW) in the direction of the arrow. The bottom or right number is the transfer capability in the opposite direction of the arrow.

NWPP-NW CAMX NWPP-NE NWPP-C DSW

Figure 3: Winter Zonal Topology Diagram

Appendix D: Probabilistic Analysis Tool

MAVRIC

The MAVRIC model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points, with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint, with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of variable energy resources (VER), and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through Loss-of-Load Probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models.

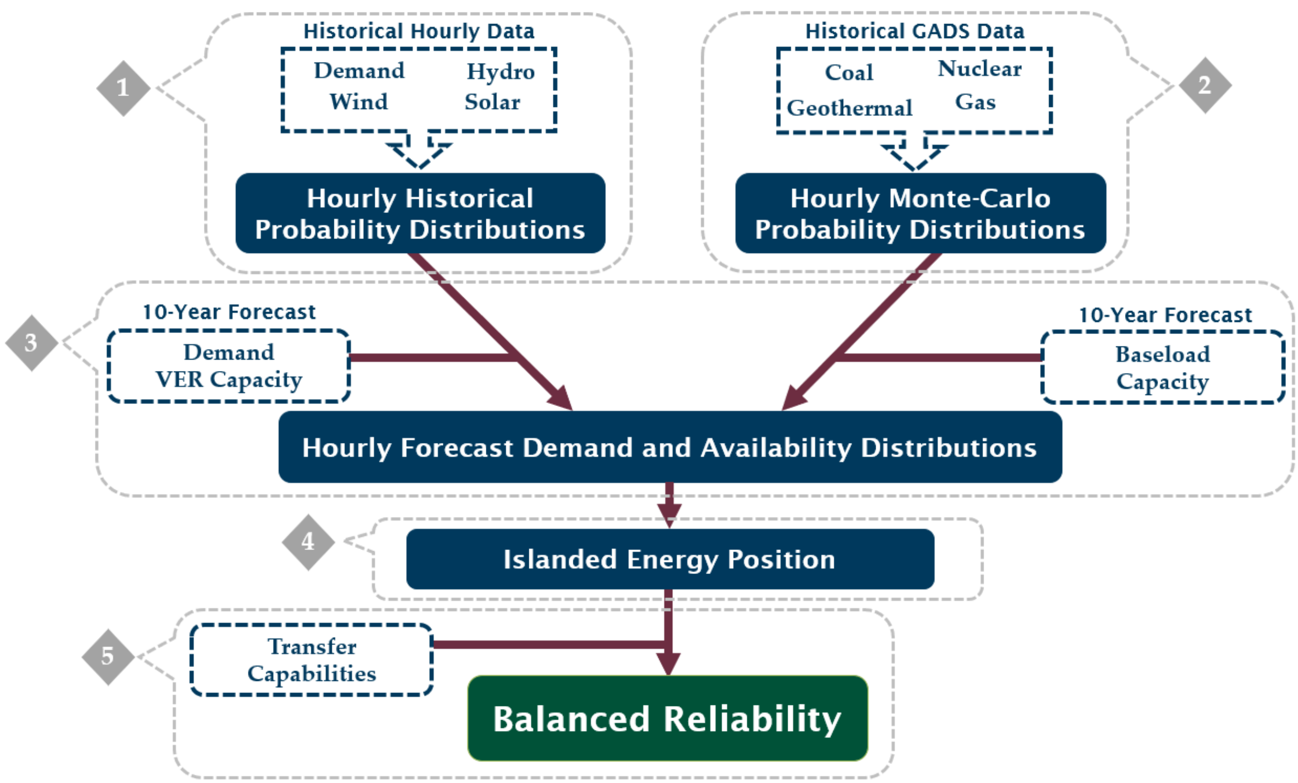


Figure 4: MAVRIC Process Flowchart

To calculate the LOLP of each of the load-serving areas, probability distributions are needed for each generating resource in the Western Interconnection, as well as for the demand of each BA.

In step one, probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the BAs in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output of this step is a series of hourly percentile profiles with different probabilities of occurring.

Figure 14 represents the probabilities for one hour. The peak is the expected deterministic forecast and is set at 100%. The profiles above or to the right of the peak are greater than 100% and those below or to the left are lower than 100% depending on the variability for each hour.

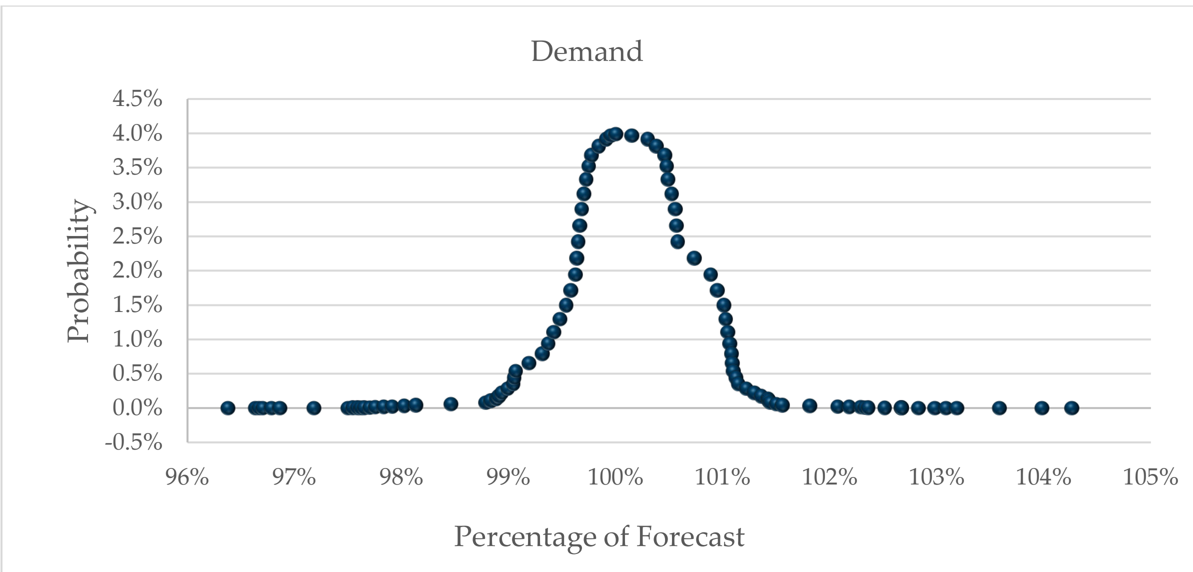
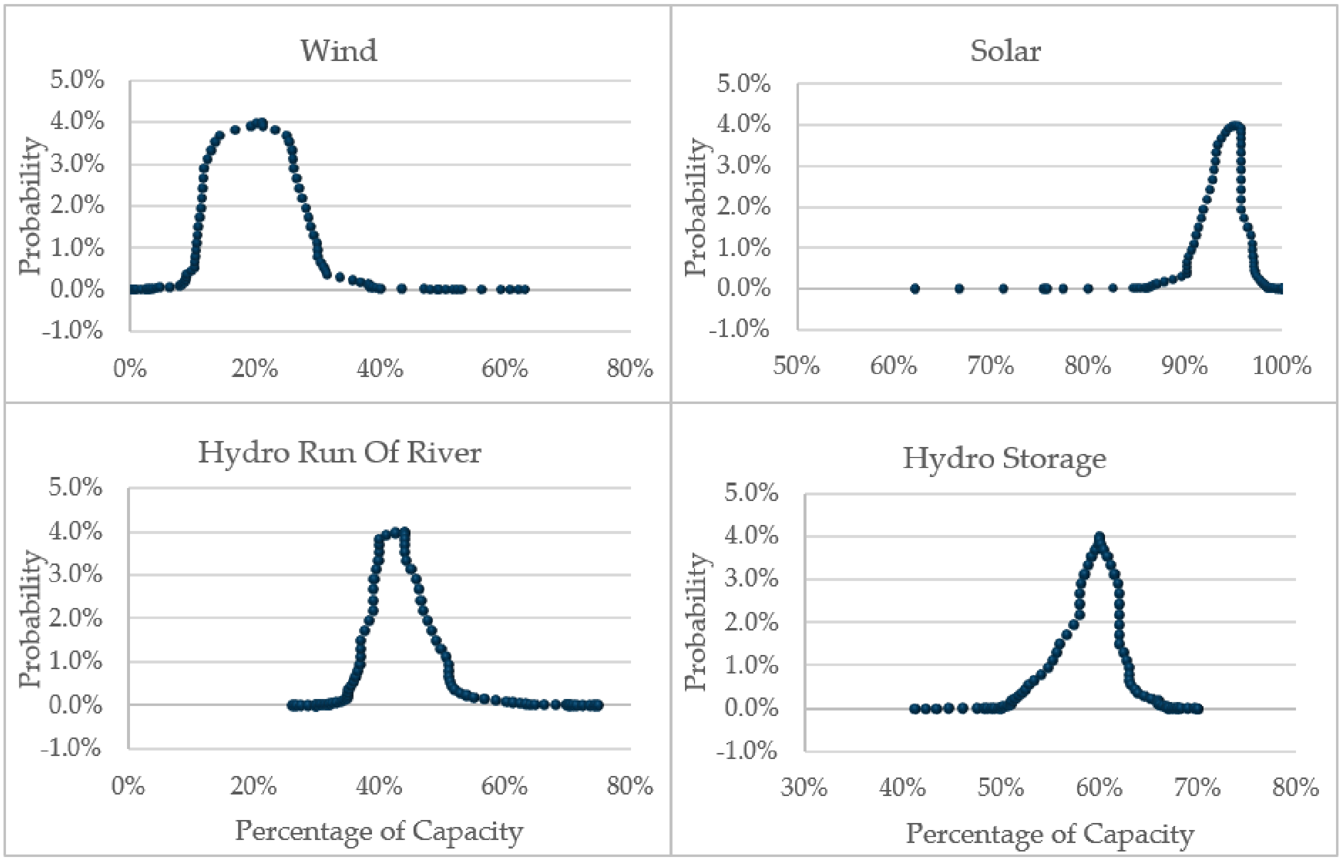


Figure 5: Demand Probability Disruption Sample

Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources), is conducted like the demand calculations but with two notable differences. The first and most significant difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability, as weather is always variable. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring. A random hour profile for each of the VER types is shown in Figure 15. Wind and hydro run-of-river units are positively skewed, while solar and hydro storage units are negatively skewed, meaning their distributions "lean" to the left and right, respectively.



Hydro facilities with storage capability are highly correlated with demand data. Although the fuel source, rain or snow runoff, is variable and not influenced by the day of the week, the ability to store the fuel leads to different operating characteristics between weekdays and weekend days. Therefore, the availability distributions for these resources are calculated the same as the demand distributions.

The distributions of the baseload resources, nuclear, coal-fired, gas-fired, and in some cases, biofuel and geothermal resources (Step 2—MAVRIC Process Flowchart), is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System (GADS). Generator operators submit data to their generating units that summarizes expected and unexpected outages that occur. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year, adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the model adheres to the mean time to recovery—meaning, for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load-serving area for each hour is then computed and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions, in that a series of hourly percentile profiles with different probabilities of occurring is produced. A random hour profile is represented in Figure 16. The peak is the expected deterministic forecast and shows a distribution that is very negatively skewed, meaning the tail to the left is longer than the right.

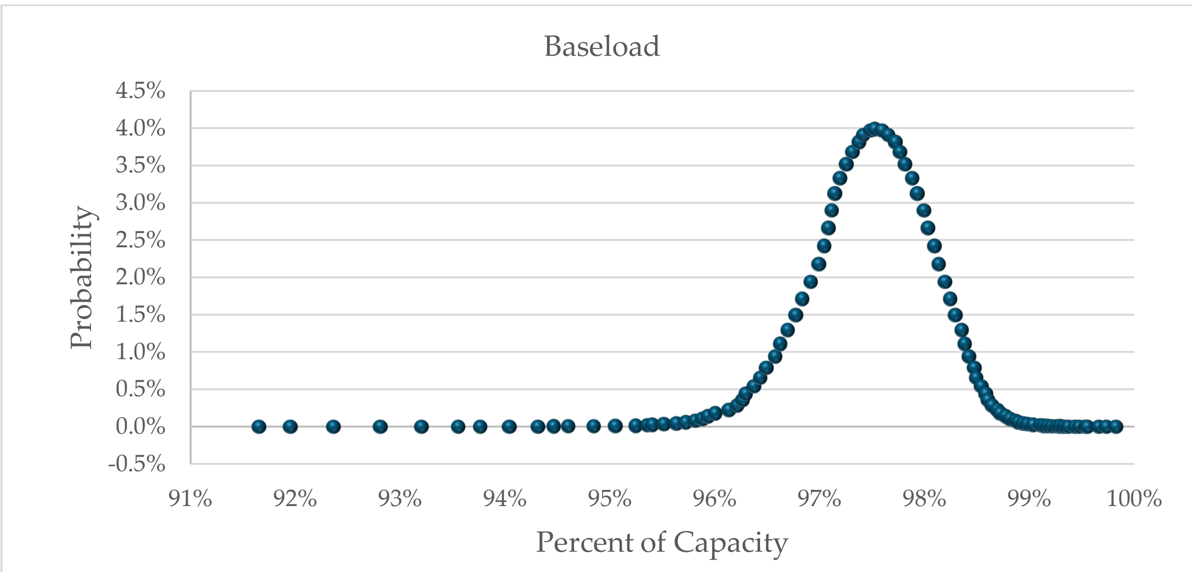


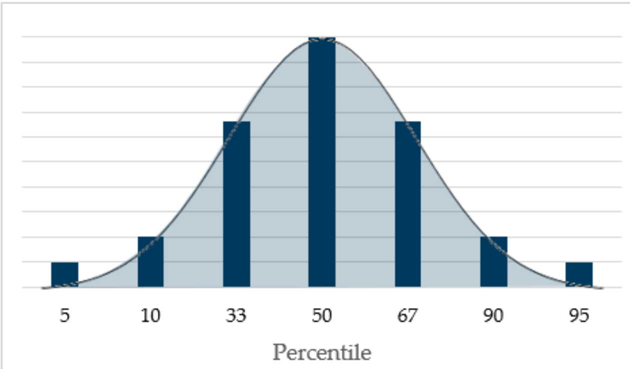
Figure 7: Baseload Probability Distribution Sample

MAVRIC then combines the 10-year forecast demand and resource capacity to represent the hourly forecast demand and availability distributions (Step 3—MAVRIC Process Flowchart). The 50th percentile of the demand distributions is set equal to 100%, with the other percentiles of the distribution ranging above and below to represent the variability in that hour (See Figure 14). The hourly demand forecast in megawatts multiplied by each of the percentiles of the probability distribution, is then used to create a distribution of hourly megawatt forecast. For generation, each of the probability distributions represent capacity factor levels of availability (See Figure 15). Therefore, by taking an expected capacity of each of the different types of resources and multiplying by each of the profiles, a distribution of hourly megawatt forecast is derived. Once the availability distributions are combined, MAVRIC compares them (Step 4—MAVRIC Process Flowchart).

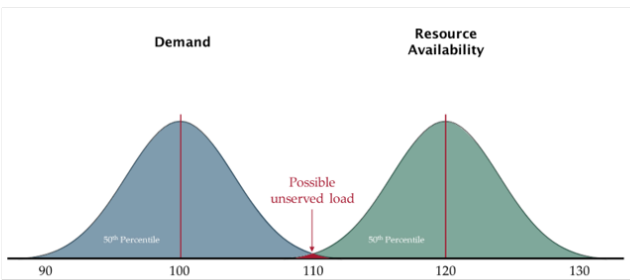
Step 4 represents the comparison of the hourly demand distributions with the generation availability distributions for each of the load serving areas. For each hour, the distributions are compared to one another to determine the amount of “overlap” in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold planning reserve margin can be determined to identify the planning reserve margin needed to maintain a level of LOLP at or less than the threshold.

If there are hours determined from the calculations in Step 4 in which the LOLP is greater than the resource adequacy threshold, MAVRIC analyzes whether imports can satisfy the deficiency (Step 5—MAVRIC Process Flowchart). MAVRIC goes through a step-by-step balancing logic in which excess energy, energy above an area’s planning reserve margin to maintain the resource adequacy threshold, can be used to satisfy another area’s resource adequacy shortfalls. This depends on neighboring areas having excess energy and there being enough transfer capability between the two areas allowing the excess energy to flow to the area of deficit. MAVRIC analyzes first-order transfers (external assistance from an immediate neighbor) and second-order transfers (external assistance from a neighboring entity’s immediate neighbors), in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas in which the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

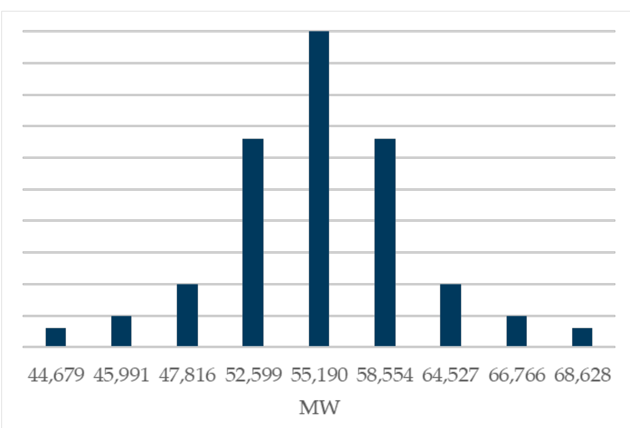
Appendix E: Guide to Charts in This Report



This graph is a generic probability curve that shows the percentile of potential demand or resource availability levels. A data point assigned to the 50th percentile represents a point at which the value is expected to fall half the time above that value and half that time below, i.e., it is the expected value. Data points assigned to the 67th or 33rd percentile each have a 33% chance of being at or above that value. Those on the 10th or 90th percentile have a 10% chance of being at or above that value, and so on.



This graph sets the demand and resource availability probability curves on the same axis to measure any overlap between the two. If any overlap exists, there is a potential for unserved load. Changing the distribution of either curve will increase or decrease the amount of overlap and any potential unserved load.



The distribution curve on this chart represents the percentile, or likelihood of occurrence, for potential demand numbers during the peak hour of 2022. The middle bar is the expected value and represents a 50% chance the observed value could be above or below that value. The two bars to its left or right have a 33% chance of being above or below that value. Throughout the report, distribution curves like this are used to represent demand and resource availability variability.

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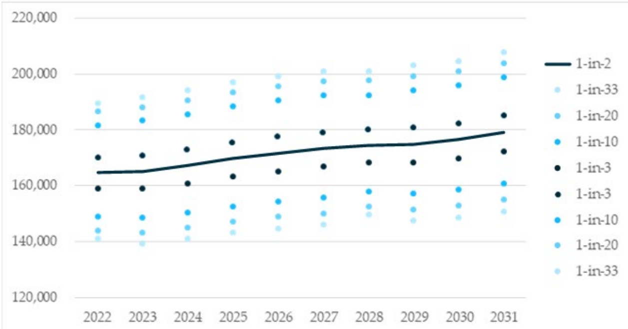
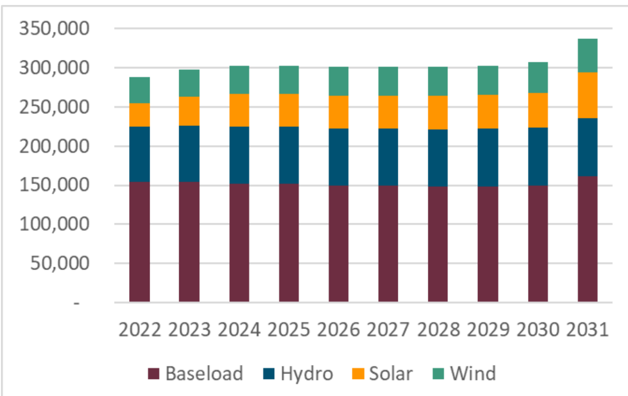
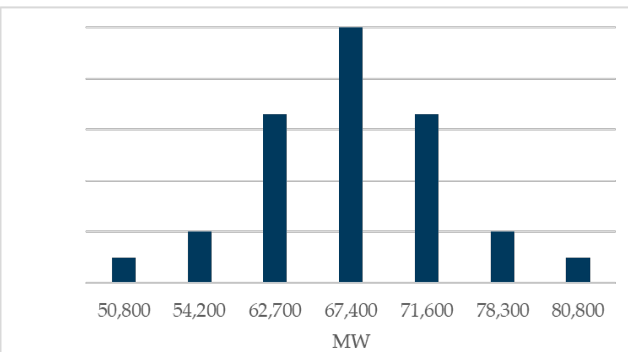


This graph shows the range of potential peak demand numbers and their probability of occurring in 2022–2031. The black line is the expected demand and the dots above and below the line represent potential demand numbers that range from a 3% chance to a 33% chance of being above or below those values. The graph highlights demand variability over the next decade.



This chart depicts the resources that will make up the generation mix each year over the next decade and their nameplate capacity.



	1-in-20	1-in-10	1-in-3	1-in-2	1-in-3	1-in-10	1-in-20
Baseload	44,600	45,600	47,900	48,900	49,700	50,700	51,100
Hydro	2,200	2,400	3,800	6,000	7,100	8,100	8,600
Solar	4,000	6,100	10,400	11,400	13,000	16,300	16,800
Wind	-	100	600	1,100	1,800	3,200	4,300

The distribution curve on this chart represents the percentile, or likelihood of occurrence, for potential resource availability during the peak hour of 2022. The middle bar is the expected value and represents a 50% chance the observed value could be above or below that value. The two bars to its left or right have a 33% chance of being above or below that value. Throughout the report, distribution curves like this are used to represent demand and resource availability variability.

The table shows the range of potential generation amounts in megawatts from each resource type on the peak hour and the probability those amounts will occur.

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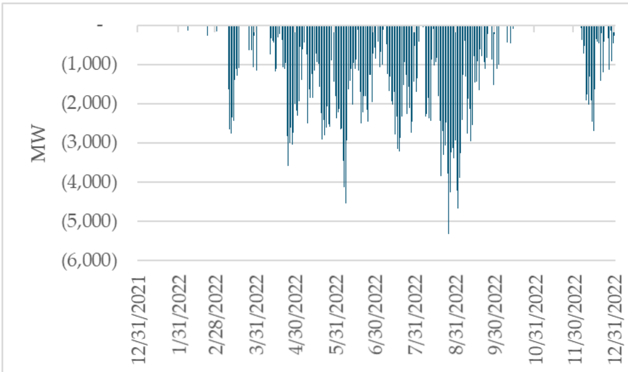
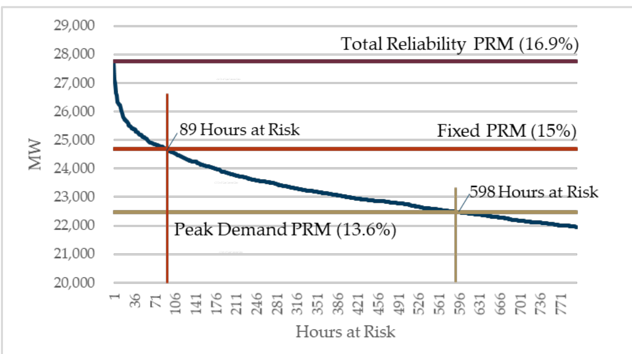
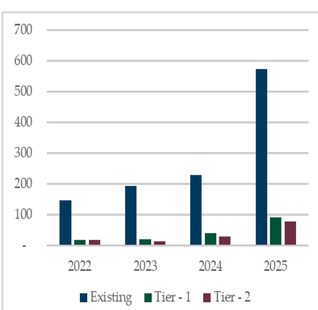
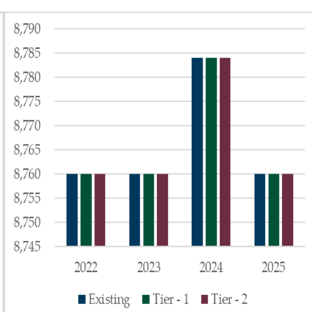


The blue lines on the chart represent an hour that has a risk of loss of load under a certain PRM. The length of the blue lines depict how many megawatts are at risk of not being served each hour.



This chart shows a duration curve of the PRMs needed for each hour of 2022 for the Western Interconnection. The three horizontal lines represent three PRMs. The chart highlights the gap between PRMs that are determined using the Peak Demand PRM or Fixed PRM approaches and the Total Reliability PRM, which is necessary to maintain 99.98% reliability for all hours.





These bar graphs show the hours and energy (GWh) at risk of not being served. Some of the charts show this information before imports are added to the analysis, others show the information after imports are added.

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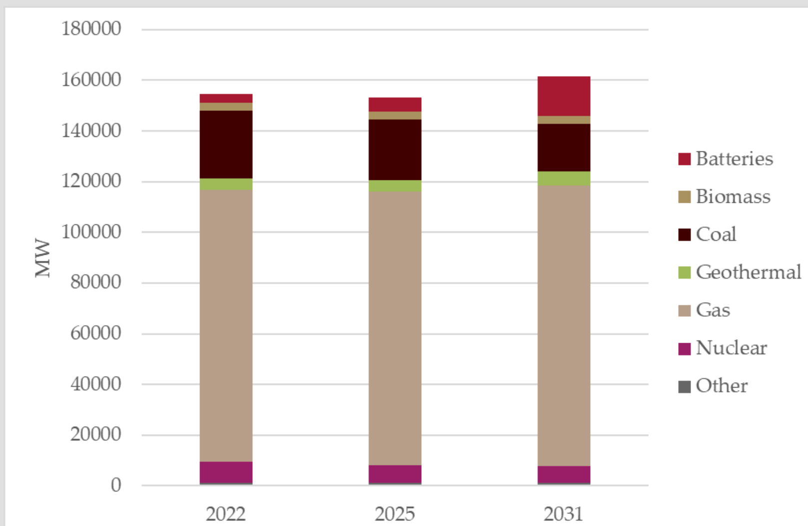
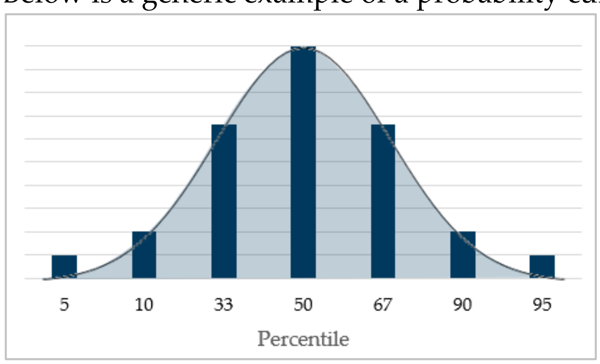
Appendix F: List of Abbreviations

Abbreviation	Meaning
BA	Balancing Authority
CAMX	California-Mexico Subregion
CAISO	California Independent System Operator
DSW	Desert Southwest Subregion
GADS	Generation Availability Data System
GW	Gigawatt
GWh	Gigawatt-hour
LOLP	Loss-of-Load Probability
MAVRIC	Multi-Area Variable Resource Integration Convolution
MW	Megawatt
MWh	Megawatt-hour
NOAA	National Oceanic and Atmospheric Administration
NWPP	Northwest Power Pool
NWPP-C	Northwest Power Pool Central Subregion
NWPP-NE	Northwest Power Pool Northeast Subregion
NWPP-NW	Northwest Power Pool Northwest Subregion
ODITY	One-day-in-ten-year
PRM	Planning reserve margin
SRSW	Southwest Reserve Sharing Group
T1	Tier 1 resources
T2	Tier 2 resources
VER	Variable Energy Resource

Appendix G: Glossary

Word	Definition
Balancing Authorities	The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.
Baseload Resources	A general category that includes the following resources: • Biomass • Coal • Geothermal • Natural and other gases • Nuclear • Batteries • Other The chart below depicts the total capacity value (in megawatts) of each baseload resource type in 2022, 2025, and 2031 for the Western Interconnection. 
Capacity value	Capacity value refers to the contribution of a power plant to reliably meet demand. The capacity value (or capacity credit) is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%).
Deterministic Analysis	A deterministic analysis is different from a probabilistic analysis in that the inputs to the model are predetermined and the results will represent these assumptions. A probabilistic model will rerun a model numerous times changing one or more input assumptions producing a range of possible outcomes.

Energy-based probabilistic approach	WECC uses an energy-based probabilistic approach for the Western Assessment. This approach calculates the Planning Reserve Margin based on energy output probabilities to account for variability. For more information on this approach, see Chapter 1.
Forced or unplanned outage	The removal from service availability of a generating unit for emergency purposes or the equipment being in an unavailable condition due to an unanticipated failure.
Hours at risk for load loss	In a given hour, if the probability that demand will exceed resource availability exceeds .02%, that hour is considered an hour at risk for loss of load. Hours at risk are not necessarily times when load loss is expected; hours at risk represent time when, if extreme conditions exist, there is a *risk* of load loss. For more information see Chapter 2.
Planning Reserve Margin	Reserve margin is the difference between available capacity and peak demand, normalized by peak demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g., extreme weather) and unexpected outages of existing capacity. From a planning perspective, planning reserve margin trends identify whether capacity additions are keeping up with demand growth.
Probability Curve	A probability curve shows the probability of potential levels of demand or resource availability based on the expected value. Below is a generic example of a probability curve. 
Reference Margin	A metric used by system planners to quantify the amount of reserve capacity in the system above the forecast peak demand needed to ensure enough supply to meet peak loads.
Shoulder Periods	Shoulder periods are times between typical peak periods, e.g., peak hour, peak season. For example, spring is a shoulder season because it sits between the winter and summer peak seasons. Shoulder seasons are usually times of transition both in system conditions like weather and in system activity like facility maintenance.

Tier 1 Resources	WECC receives annual data submittals from Balancing Authorities that include demand and resource projections for the next 10 years. Resource additions are categorized in tiers. Tier 1 includes resources that are under construction.
Tier 2 Resources	WECC receives annual data submittals from Balancing Authorities that include demand and resource projections for the next 10 years. Resource additions are categorized in tiers. Tier 2 includes resources that have started an approval process such as licensing, siting, or permitting but are not yet under construction.
Tier 3 Resources	WECC receives annual data submittals from Balancing Authorities that include demand and resource projections for the next 10 years. Resource additions are categorized in tiers. Tier 3 resources are generic placeholder generation assumptions entities use to account for future resource needs. Starting with year 5, there are many more Tier 3 resources reported by BAs, which are resources that are planned but not yet in the regulatory or approval process. Tier 3 resources are much less of a certainty than Tiers 1 and 2, and some may only be conceptual resources that a BA knows must be added but does not yet have concrete plans for. In some cases, there are no resource additions reported by BAs for years 5–10, or all the resource additions are reported in year 10. Given the uncertainty of the resource availability and demand data for years 5–10, an analysis of these years can only provide a general idea of whether our current resource plans will position the interconnection to be resource adequate.
Variable Energy Resources	Resources that produce energy intermittently instead of on demand. They are often considered weather-dependent resources, like solar or wind generation.