Resource Adequacy in the Desert Southwest

Final Report

February 2022

Energy+Environmental Economics

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Acknowledgements & Disclaimer

Sponsors

This study was jointly funded by the following utilities:

- Arizona Public Service Company (APS)
- Arizona Electric Power Cooperative (AEPCO)
- El Paso Electric Company (EPE)
- Public Service Company of New Mexico (PNM)
- Salt River Project (SRP)
- Tucson Electric Power Company (TEP)

Technical Advisory Group

Over the course of this study, E3 convened a Technical Advisory Group comprising individuals with expertise and interests in resource adequacy. These individuals graciously shared their time through several meetings, providing their feedback on the project's scope, technical analysis, and key findings. The Technical Advisory Group included the following individuals:

- **Aidan Tuohy**, Electric Power Research Institute
- **Bethany Frew**, National Renewable Energy Laboratory
- **Branden Sudduth**, Western Electricity Coordinating Council
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- **Gord Stephen**, National Renewable Energy Laboratory
- **John Moura**, North American Electric Reliability Corporation
- **Kory Hedman**, Arizona State University
- **Matt Elkins**, Western Electricity Coordinating Council
- **Maury Galbraith**, Western Interstate Energy Board
- **Pat O'Connell**, Western Resource Advocates

E3 would like to thank the Technical Advisory Group for their valuable contributions over the course of the study. Participation in the Technical Advisory Group does not indicate endorsement of the report's findings.

Disclaimer

The study sponsors retained E3 to provide an independent assessment of the resource adequacy situation in the Desert Southwest region. The sponsors provided technical information and informed the development of study scenarios. E3 utilized data from the study sponsors and other sources to develop a Southwest resource adequacy model. E3 retained full editorial control over the report and is solely responsible for all contents.

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Acronyms

Acronym	Definition
ACC	Arizona Corporation Commission
AEPCO	Arizona Electric Power Cooperative
APS	Arizona Public Service Company
BAA	Balancing Authority area
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRSP	Colorado River Storage Project
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EPE	El Paso Electric Company
ESIG	Energy Systems Integration Group
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
HILF	High Impact Low Frequency
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
PNM	Public Service Company of New Mexico
RECAP	Renewable Energy Capacity Planning Model
SRP	Salt River Project
TEP	Tucson Electric Power
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WRAP	Western Resource Adequacy Program

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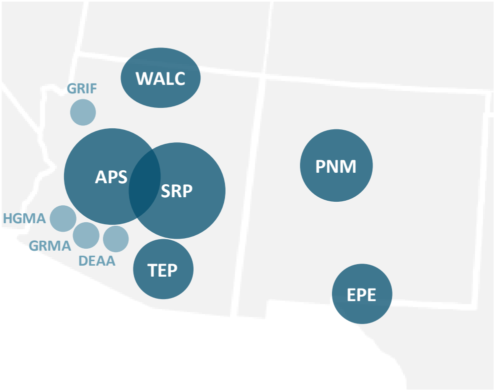
Executive Summary

In the aftermath of recent blackouts in California and Texas, the subjects of reliability and resource adequacy have risen to national prominence. Regulators and policymakers – as well as the general public and media – have taken a keen interest in these topics, and many have questioned whether the industry is adequately prepared to confront the challenge of preserving reliability during a period of rapid transition. Yet despite its importance and the recent attention it has received, the topic of resource adequacy – and what will be needed to ensure it can be maintained during the transition to cleaner energy sources – remains an esoteric and poorly understood aspect of power system planning. This study sheds light on this important topic to support utilities, regulators, policymakers, and stakeholders in the Desert Southwest as they endeavor to plan, construct, and operate a reliable grid. The goals of this study are threefold:

Figure ES-1. Study geographic scope



1. Examine the current situation in the Desert Southwest in light of recent challenges in neighboring regions and identify any immediate risks to reliability in the region;
2. Identify and define best practices for resource adequacy planning that will provide a durable foundation for utilities' efforts to preserve reliability within the region; and
3. Utilize these techniques to evaluate the region's readiness to meet the resource adequacy challenges it will face over the next decade.

Study Highlights & Recommendations

- **Load growth and resource retirements are creating a significant and urgent need for new resources in the Southwest region; maintaining regional reliability will hinge on whether utilities can add new resources quickly enough to meet this growing need and will require a pace of development largely unprecedented for the region**
- **An increasingly significant share of long-term resource needs is expected to be met with solar and storage resources, but a large quantity of "firm" generation capacity – including the region's nuclear and natural gas resources – will also be needed to maintain reliability**
- **Substantial reliability risks remain as the region's electricity resource portfolio transitions, most notably: weather- and climate-related uncertainties, performance of battery storage, and risks related to the timing of new additions**
- **To plan most effectively for resource adequacy, utilities should utilize the best practices identified in this study to the extent practicable, including the use of probabilistic methods to assess the need for capacity and the broad application of an ELCC methodology to assess the capacity value of all resources on an equivalent basis**

New Challenges in Resource Adequacy in the Southwest

Due to a far-reaching combination of factors – technological, economic, policy, environmental and societal dynamics – the energy landscape of the Southwest region is in a period of rapid transformation. Many of these changes have direct implications on the utilities' ability to maintain reliable electric service. Figure ES-2 summarizes six key trends that are fundamentally altering the Southwest's energy system and will have large and immediate ramifications for resource adequacy planning in the region.

Figure ES-2. Key trends reshaping the Southwest

Load growth
Expected 2+% load growth resulting from net migration, electrification, and new large customers

Climate change impacts on extreme weather
Increased frequency and intensity of extreme heat events results in more frequent extreme peaks

Planned coal & gas retirements
Announced retirements total 1.4 GW by 2025 and 5 GW by 2033

Increasing risk of sustained drought
Hydroelectric generation facilities susceptible to significant impacts under drought

Rapidly increasing reliance on renewables, storage, and DERs
Resource additions driven by policy, customer preferences, voluntary commitments, and economics

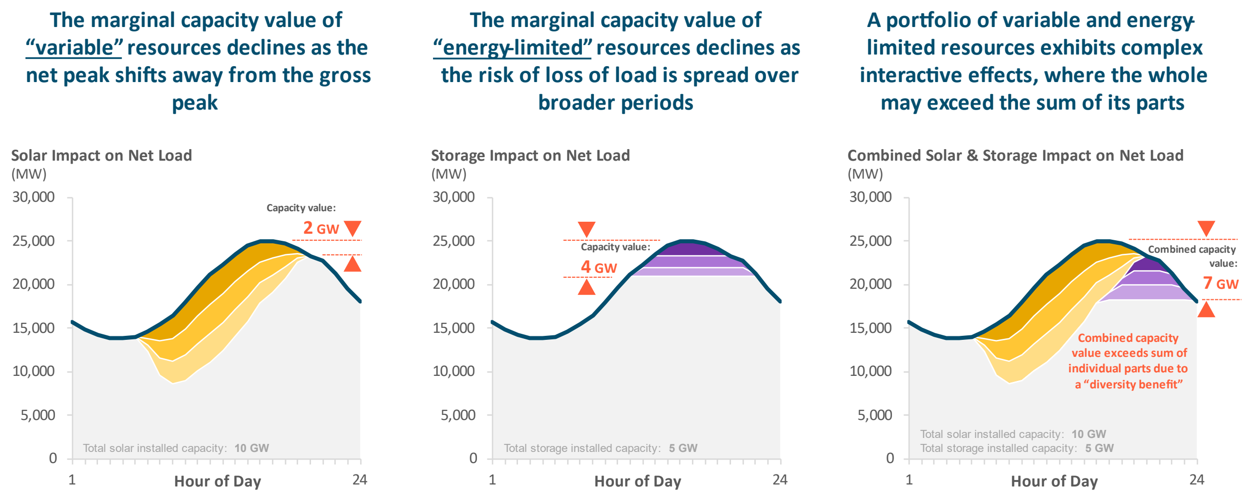
Tightening Western markets
Changes & trends across the broader Western Interconnection reshaping market dynamics

While each of these trends will impact utilities' efforts to plan for reliability, the shift towards a portfolio more heavily reliant on renewables, storage, and distributed energy resources is notable because it will require advances beyond the simple techniques and common heuristics that have been used in planning for decades. The North American Electric Reliability Corporation (NERC) has described this transition "the greatest challenge to reliability"[1]; a growing body of research has shed light on the complex dynamics of how variable and energy-limited resources impact resource adequacy (illustrated in Figure ES-3):

1. As the penetration of variable resources grows and traditional generation retires, the periods in which the system is most vulnerable to reliability risks shift away from the traditional peak and toward periods of lower renewable production; this effect is exemplified by the shift in reliability risk to the evening net peak that occurs as solar penetration increases.
2. As the penetration of energy-limited resources grows, the risk of loss of load events will spread across an increasing number of hours; as the number of hours in which the system is at risk increases, the value of energy-limited resources with finite durations diminishes.
3. Variable and energy-limited resources exhibit complex "interactive effects," meaning that the combined value of a portfolio of resources may differ from the sum of its individual parts.

[1] NERC, 2021 Long Term Resource Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

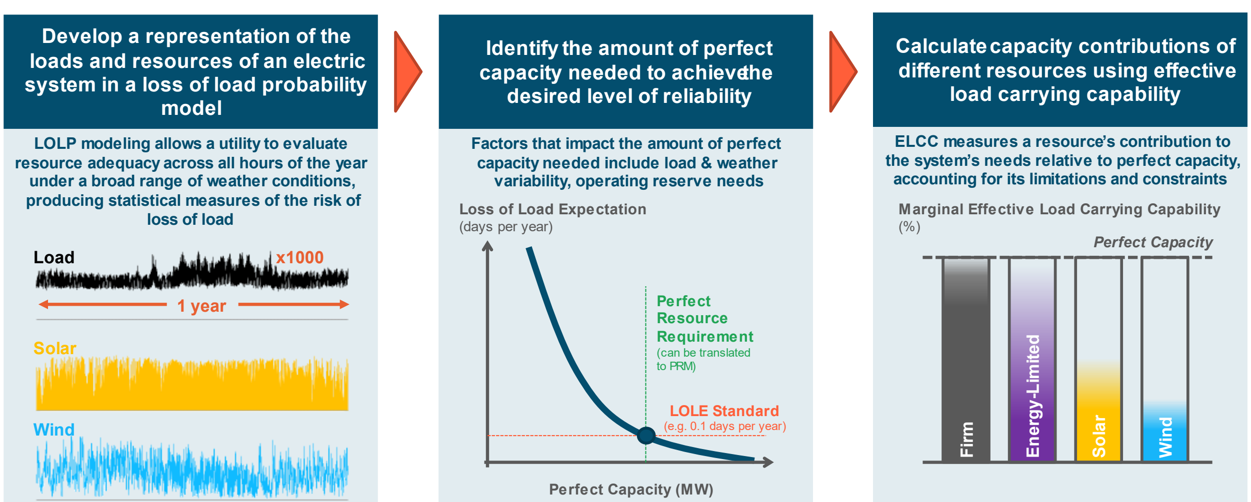
Figure ES-3. Three new complexities in resource adequacy planning resulting from growing penetrations of variable and energy-limited resources



Best Practices for Resource Adequacy Planning

The trends described above pose challenges to resource adequacy planners, but these challenges are not unique to the Southwest region. Utilities, regulators, and stakeholders throughout the country and around the world have already taken important steps to modernize their approaches to resource adequacy planning. "Best practices" continue to evolve as the understanding of these challenges advances and new information becomes available. However, the basic foundation of a robust framework for future resource adequacy planning is well-established and relies on the use of a **loss of load probability (LOLP) model** to (a) establish a **planning reserve margin (PRM)** requirement and (b) evaluate the effectiveness of resources using an **effective load carrying capability (ELCC)** methodology.

Figure ES-4. Best practices in future resource adequacy planning

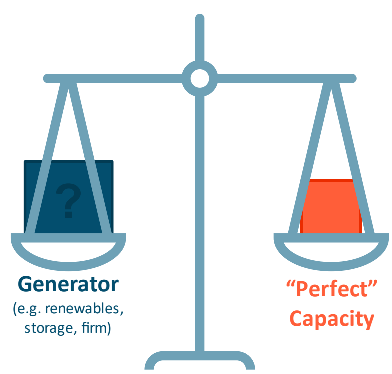


Probabilistic methods for resource adequacy analysis (or LOLP models) were first popularized in the middle of the twentieth century when planners recognized the usefulness of measuring risks to reliability statistically based on probabilities of extreme weather events and power plant outages. Today and in the future, reliability outcomes will continue to depend on weather variability (and its impacts on load, renewables, and other resources) and generator availability; the idea of a probabilistic approach to measuring reliability risk remains fundamentally sound, and the methods established in this early era serve as a foundation for the future of resource adequacy planning. However, the complexity of the probabilistic simulations needed will increase significantly as an unavoidable consequence of the transition to a portfolio that is less reliant upon conventional firm resources. The future of resource adequacy depends upon continued enhancements to probabilistic methods and data that capture this complexity, including simulation of chronological operations and resource interactions and considering weather variability, energy use limitations, and evolving load patterns.

While rigorous probabilistic modeling is essential to planning for resource adequacy for a power system, it is also important to understand how individual resources contribute to system reliability. To this end, a complementary capacity-based accounting construct akin to the familiar "planning reserve margin" will also remain useful. The key to robust capacity accounting is that all megawatts of capacity – both the requirement and the contribution of resources – be denominated in terms of "perfect capacity," a unit of capacity that is available in all hours of the year at full capacity. The use of this fictional benchmark to both establish the requirement and count resources towards it provides for a balanced, technology-agnostic framework that values each resource based on its relative contribution to system needs.

Within this framework, the capacity value assigned to each resource (or portfolio of resources) should be determined using an ELCC methodology, which relies on the same LOLP modeling techniques to determine the amount of perfect capacity that provides an equivalent value to system reliability. Properly applied, an ELCC-based framework for capacity accreditation naturally accounts for the oft-cited complications that will arise in this transition, including the "shift to the net peak," the need to account for energy sufficiency as well as capacity, and the saturation effects and diversity benefits that accrue to portfolios of variable and energy-limited resources. ELCC is therefore broadly viewed as the cornerstone of a robust approach to capacity accreditation and has quickly gained widespread usage within the industry.

Figure ES-5. Effective load carrying capability (ELCC) as a measure for resource accreditation



A resource's ELCC is a measurement of the amount of perfect capacity that provides an equivalent reliability benefit to the system

Analysis Highlights

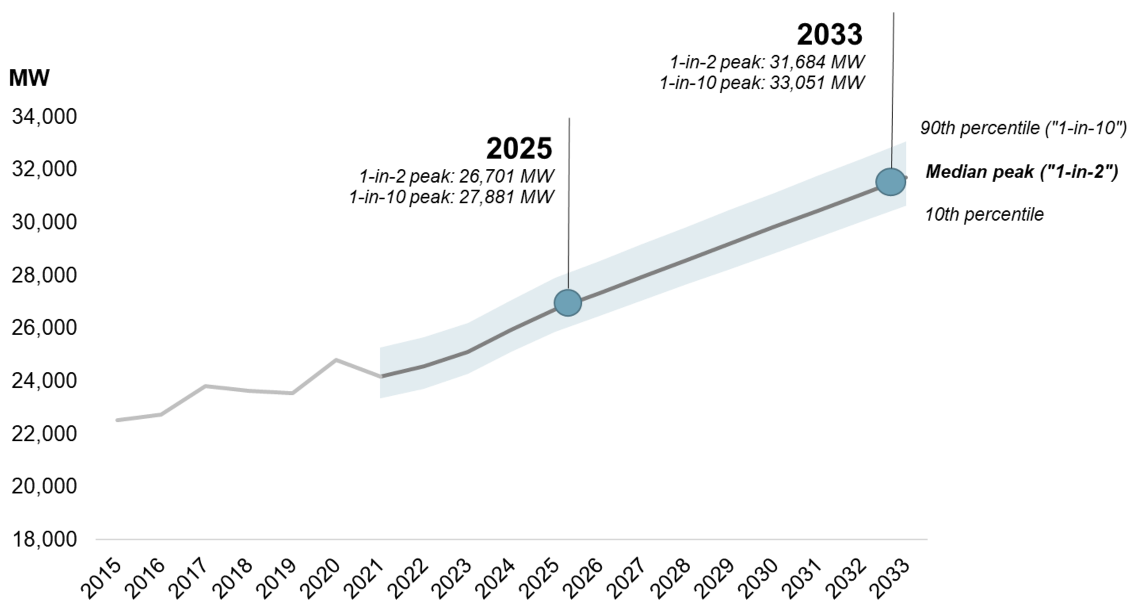
This study relies on E3's **Renewable Energy Capacity Planning (RECAP)** model, a chronological loss-of-load probability (LOLP) model to analyze the evolution of resource adequacy needs of the Southwest over the decade. The analysis addresses three questions over this time horizon:

- How much new capacity is needed to ensure resource adequacy in the region?
- How effective are different types of resources in meeting this need, considering their specific constraints and limitations?
- Do the utilities' current resource plans, as reflected by the portfolios produced in their IRPs, position the region to meet resource adequacy needs in the future?

Regional Demand Forecast

A region's demand for electricity – in particular, its highest "peak" demand – is the main driver of its capacity needs for resource adequacy. For this study, an hourly future load forecast representative of the Southwest region as a whole was developed through aggregation of individual utilities' annual load forecasts and historical hourly load shapes. In aggregate, peak demand in the region is forecasted to grow significantly in the coming years due to net migration to major population centers in the region, increased adoption of electric vehicles, and the growing trend of new large commercial and industrial customers. Based on utilities' projected impacts of these trends, regional coincident peak under "typical" weather conditions is expected to grow by roughly 700 MW per year across the study horizon, reaching 26,700 MW by 2025 and 31,700 MW by 2033. Of course, more extreme weather conditions that occur during some years could result in even higher peak demands; this possibility is captured in the analysis by simulating hourly load shapes under 70 distinct weather years to capture potential year-to-year variability in extreme temperatures and peak demand.

Figure ES-6. Projection of regional coincident peak demand resulting from utility load forecasts

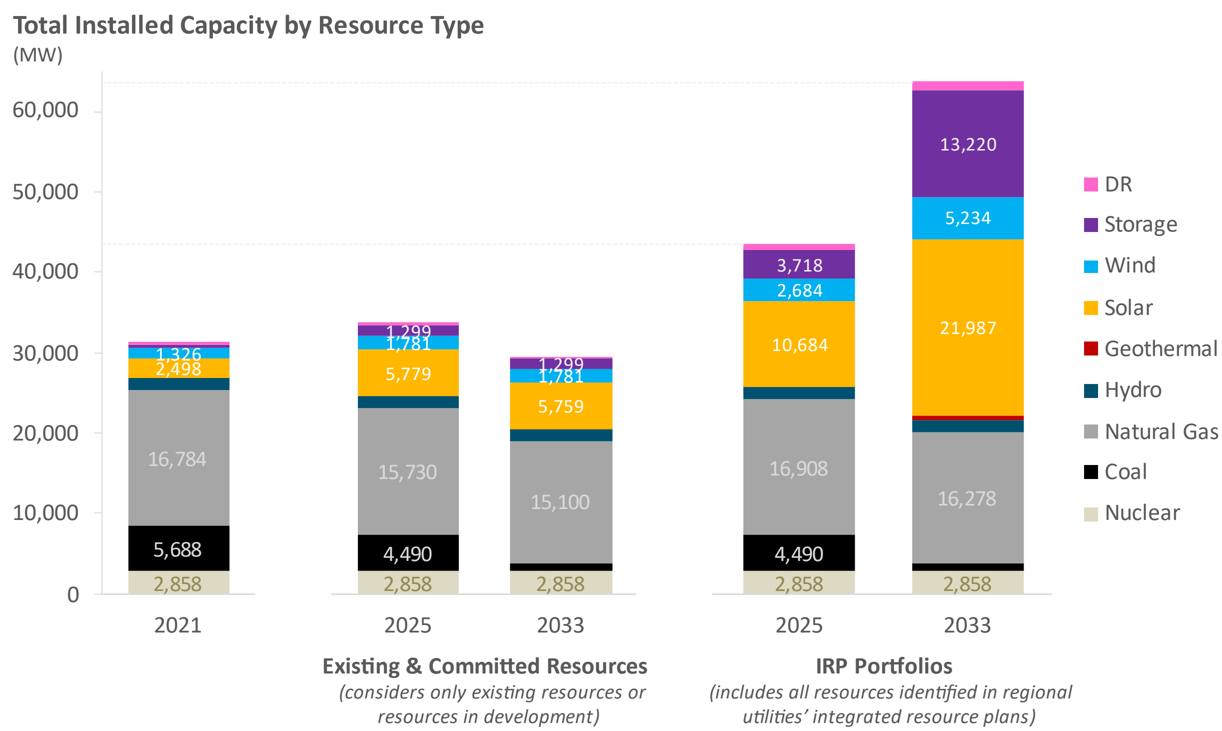


Regional Resource Portfolios

This study focuses on the ability of two future resource portfolios to meet the region's reliability needs in two snapshot years (2025 and 2033); the installed capacity of different resources in each of these scenarios is illustrated in Figure ES-7. All four portfolios incorporate retirements of coal and natural gas resources as currently planned by utilities within the region, totaling 1,400 MW of capacity by 2025 and 5,400 MW by 2033. New additions vary according to scenario:

- The **"Existing & Committed Resources"** scenarios include only new resources that have executed contracts with utilities and/or requisite regulatory approvals, which include roughly 3,000 MW of new solar and 1,200 MW of new energy storage.
- The **"IRP Portfolios"** scenarios include all future resource additions captured in utilities' current IRPs (or comparable planning processes) in addition to the existing & committed resources; these additions total roughly 10,000 MW of new installed capacity by 2025 and 35,000 MW by 2033, comprising large amounts of solar and storage and smaller amounts of wind, geothermal, demand response, and natural gas.[2]

Figure ES-7. Resource portfolios analyzed in this study



[2] At the time of this study, the additional resources included in the IRP portfolios did not meet the criteria defined to qualify as "committed additions" for the purposes of this study. However, many of the additional resources included in utilities' IRPs in the near term are already under development.

Summary Reliability Statistics

Outputs from the LOLP simulation of each of these four scenarios are summarized in Table ES-1. These results inform several notable observations:

+ As of 2021, the region's loads and resources were roughly in balance; the frequency of expected unserved energy events was slightly higher than a traditional "one-day-in-ten-years" reliability standard. This reliability benchmark (an LOLE of 0.1 days per year) is used throughout this study as a reference point for resource adequacy.
+ Existing and committed resources alone will be insufficient to meet the region's reliability needs. Without additional resources, the region's resources would be insufficient to meet demand 12 days each year – far more than envisioned in a "one-day-in-ten-year" standard. Filling this gap will require close to 4,000 MW of new effective capacity by 2025 and over 13,000 MW by 2025.
+ The utilities' plans for new resources, as reflected in their IRPs, appear sufficient to meet regional reliability needs as defined by a "one-day-in-ten-years" standard under Base Case assumptions of load and resource performance.

Table ES-1. Summary results from four scenarios studied

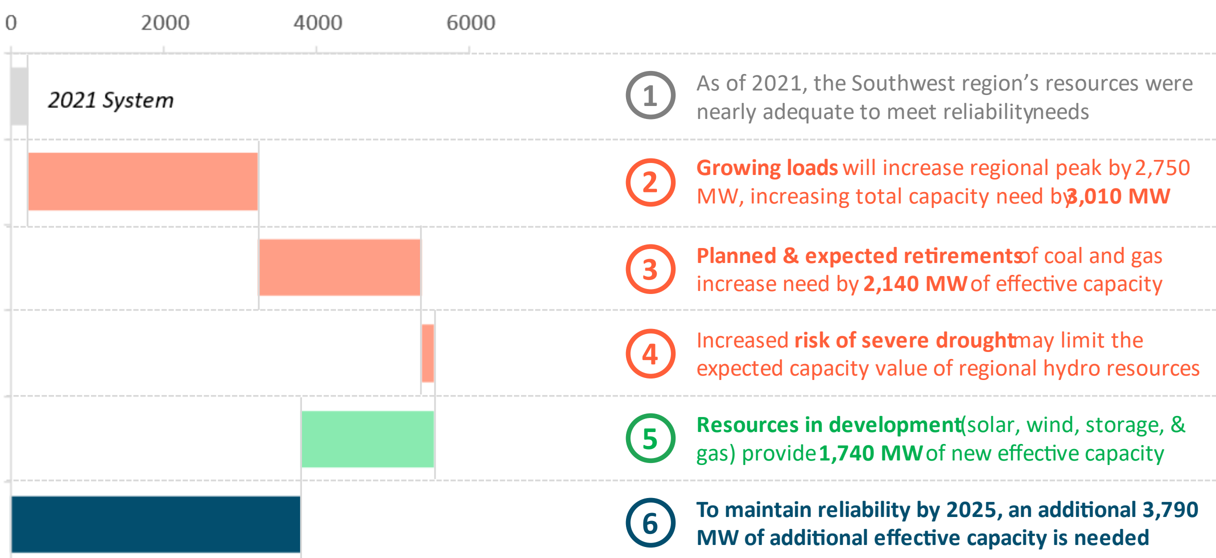
	Existing & Committed			IRP Portfolios	
Metric	**2021**	**2025**	**2033**	**2025**	**2033**
Loss of Load Expectation *(days per year)*	**0.15**	**12**	**140**	**0.04**	**0.01**
Average Event Duration *(hours per event)*	3.0	3.0	10	1.9	1.2
Capacity Surplus (Shortfall) *(effective MW, relative to 0.1 LOLE)*	**(225)**	**(3,789)**	**(13,227)**	**760**	**1,356**

Key Findings

1. Load growth and resource retirements are creating a significant need for new resources in the Southwest region

Between 2021 and 2025, utilities in the region anticipate growth in electric loads of roughly 2.4% per year, increasing the regional coincident peak demand from 24,000 MW to 26,700 MW. Over the same horizon, utilities plan to retire roughly 1,200 MW of coal capacity and 1,300 MW of natural gas capacity. In a system that is already close to load-resource balance in 2021, the compound effect of these two changes – plus the potential effects of increased drought risk on hydro production – create a total need for new effective capacity of roughly 5,000 MW. Resources under development today, which comprise a mix of solar, storage, wind, and natural gas, are together capable of meeting a portion – but not all – of this deficit. The remaining gap – which is summarized in Figure ES-8 – amounts to nearly 4,000 MW of effective capacity. In a system that is already on the cusp of an acceptable level of reliability today, the ability of the region's utilities to preserve reliability over the next few years will depend on their success in bringing new resources online in a timely manner to address this shortfall.

Figure ES-8. Changes in the load-resource balance of the Southwest region, 2021-2025

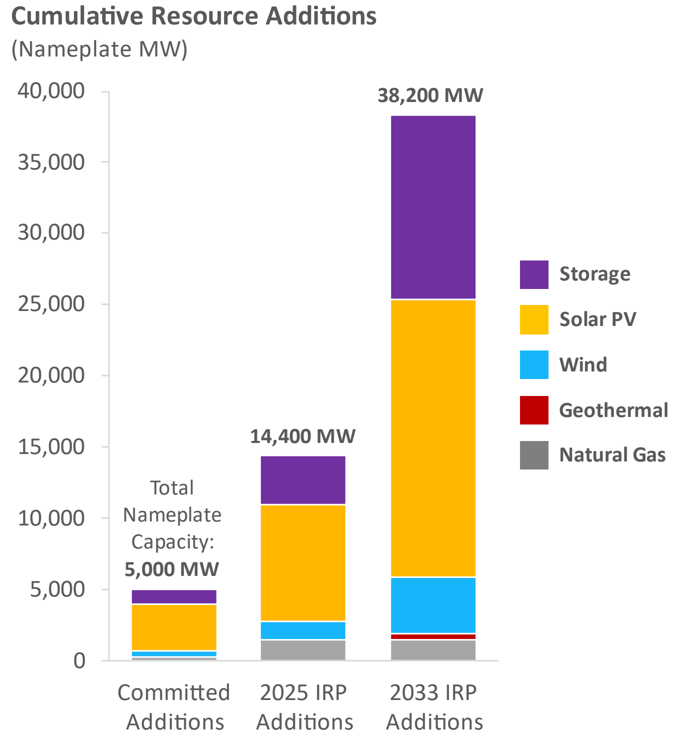


Notes
1. "Effective capacity" measures a resource's contribution to resource adequacy relative and is typically less than its nameplate capacity; the amount of new nameplate capacity needed to ensure resource adequacy will exceed – likely by a multiple of three to four times – the amount of new effective capacity needed
2. Resources in development within the region include solar (3,281 MW), storage (1,040 MW), wind (455 MW), and gas (228 MW)

The need for new capacity will continue to grow beyond 2025, driven largely by the compound effects of load growth and resource retirements. If the growth as projected by the region's utilities continues, peak demand could reach 31,700 MW by 2033. At the same time, the total amount of coal and natural gas capacity expected to retire between 2021 and 2033 is 6,400 MW, roughly one third of the total coal and natural gas capacity serving the Southwest region today. Due to this combination of changes, the amount of new effective capacity needed within the region would grow to 13,000 MW.

2. Utilities' current resource plans have identified enough resources to maintain regional reliability over the next decade

Figure ES-9. New resource additions included in regional utilities' IRPs



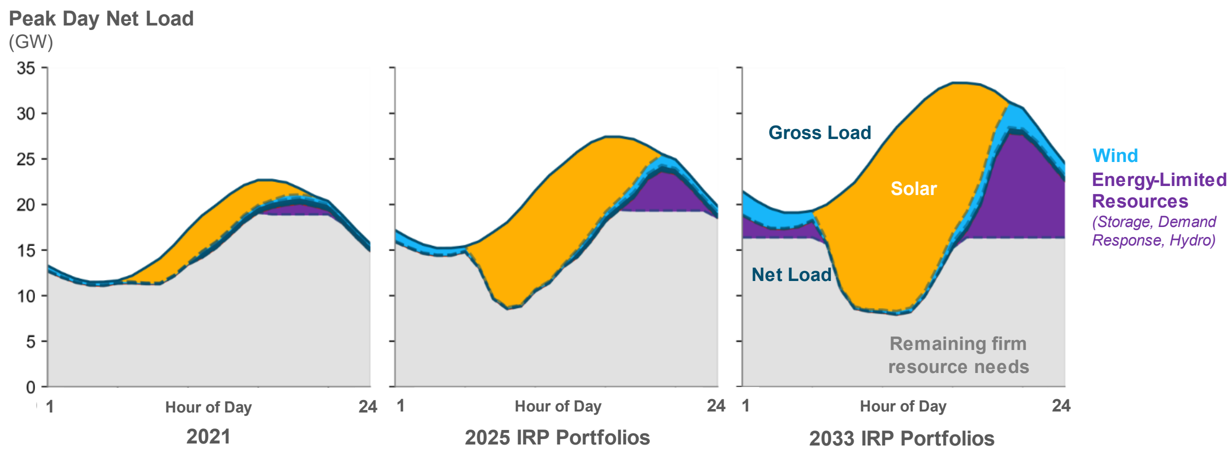
Utilities' integrated resource plans, each designed to achieve a balance between affordability, reliability, and sustainability, identify plausible portfolios of future resources to meet anticipated needs. In addition to the 5,000 MW of resources already under development, the region's utilities' plans include a total of 10,000 MW of additional nameplate capacity, most of which is solar and battery storage. By 2033, total additions of nameplate capacity approach 35,000 MW. The breakdown of these capacity additions is shown in Figure ES-9. Notably, the amount of *installed* capacity needed to maintain reliability far exceeds the amount of *effective* capacity needed; this is an expected result due to the inherent limits of variable and energy-limited resources to contribute to system resource adequacy needs.

This quantity of new resource additions is found to be sufficient to meet a regional reliability standard of "one day in ten years". If all resources included in utility IRPs come online during the timeframes identified, the region will maintain a small surplus of effective capacity over the 2021-2033 time horizon under the Base Case. This finding notwithstanding, utilities' individual standards for resource adequacy will continue to govern their future resource needs, and the degree to which each utility's respective plan achieves a satisfactory degree of reliability should ultimately be determined based on the their portfolio's ability to serve their loads.

3. A significant share of long-term resource needs is expected to be met with solar and storage, which together are well-suited to meet a large portion of the region's loads on summer peak days

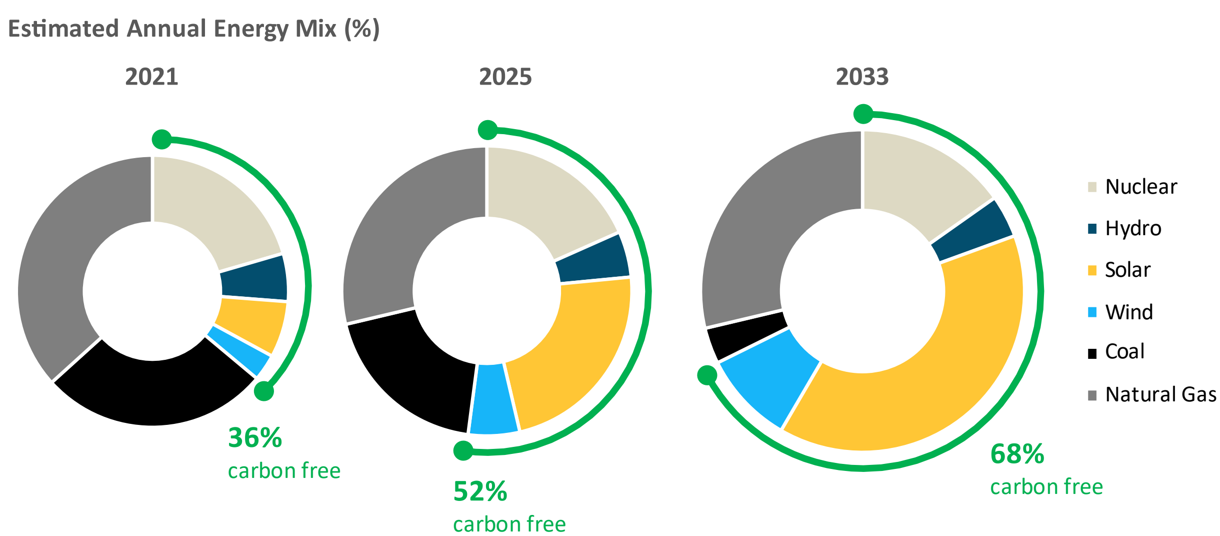
By 2025, the aggregate portfolio of variable and energy-limited resources – predominantly solar and storage – will comprise approximately 44% of the region's total nameplate capacity, providing roughly 25% of the region's need for effective capacity. By 2033, wind, solar and battery storage will comprise 68% of nameplate capacity and nearly 50% of effective capacity. This transition is illustrated in Figure **ES-10**, which depicts the role of variable and energy-limited resources on a typical "peak" day in the Southwest region in each of the snapshot years examined in this study. The combination of solar and energy storage is found to be particularly effective and well-suited to meet a large share of the Southwest region's resource adequacy needs; on a typical summer peak day, solar produces at high capacity factors throughout the day, while storage resources – charged during periods of surplus generation – provide generation during the evening "net peak" (the period when load minus wind and solar generation is highest) and into the night.

Figure ES-10. Increasing roles for variable and energy-limited generation in meeting resource adequacy needs in the Southwest



It is worth noting that while the contribution of variable and energy-limited resources to system resource adequacy needs is projected to become significant in utilities' IRP portfolios, their respective shares of the region's energy generation will be even larger. Figure ES-11 highlights the evolution of the region's annual energy mix under the utilities' current plans. By 2033, utilities' IRPs rely on solar (along with energy storage to support its integration) to supply 40% of annual energy needs; total carbon-free annual generation will account for nearly 70% of annual energy needs. This reflects an important axiom in the transition to a highly renewable electricity system: variable resources' share of the annual energy mix – and by extension, their impacts on greenhouse gas emissions – will grow more quickly than their relative contributions to resource adequacy needs.

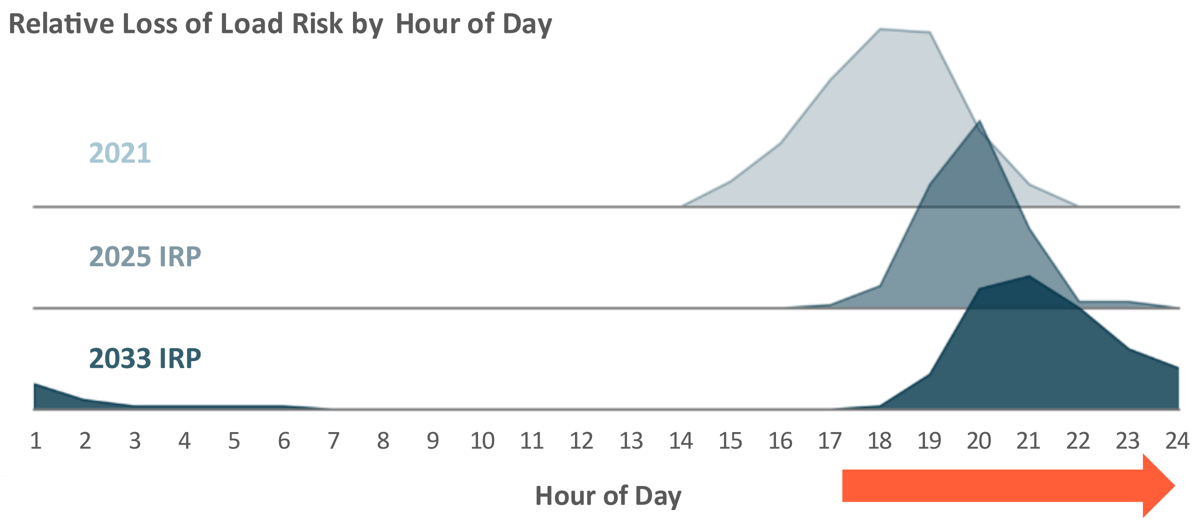
Figure ES-11. Annual energy mix achieved under utility IRP scenarios



4. The Southwest will continue to rely on a large quantity of "firm" generation resources to maintain resource adequacy; the region's remaining nuclear and natural gas resources will be crucial to meeting the need for firm resources through the study horizon and beyond

One of the profound consequences of the region's increasing reliance on solar and storage resources is that the timing of the greatest reliability risks will change. By 2025, the evening "net peak" will become more constraining than the historical late afternoon peaks due to saturation of daylight hours with solar energy. Deployment of energy storage at scale will further extend the constraining periods into the evening and nighttime hours. This transition is illustrated in Figure ES-12 below.

Figure ES-12. The changing profile of reliability risk in the Southwest as the region transitions to higher penetrations of solar and storage



The changing composition of the portfolio impacts the timing of reliability risks:
- High levels of solar shift risk to the evening net peak
- Storage "flattens" the net peak, extending risk into nighttime

As this transition occurs, the effectiveness of incremental solar and energy storage resources in their contributions to resource adequacy will diminish; this dynamic is reflected in their declining marginal capacity values, as measured using ELCC. Beyond 2025, as the reliability risk shifts into the evening, the marginal capacity value of solar will remain below 10%; by 2033, once the penetration of storage has increased significantly, the marginal capacity value of four-hour energy storage declines below 50%.

The changing character of this risk – and the declining ELCCs of solar and storage – highlights the need for resources that are capable of delivering energy to the system for sustained periods from early evening until morning. For this reason, conventional firm capacity resources will continue to play a crucial role in meeting resource adequacy needs alongside a burgeoning portfolio of renewable, storage, and demand-side resources. Through the time horizon considered in this study, the region's remaining nuclear and natural gas generators, which total nearly 20 GW of installed capacity, will be needed to fulfill this crucial role.

5. Substantial reliability risks will accompany the transition of the region's electricity resource portfolio; managing and responding to these risks will require continuous efforts to refresh resource adequacy planning as more information becomes available and utilities gain more experience operating new resource portfolios

The most significant risk factors that could threaten the reliability of the grid include:

- **Climate impacts:** climate change will continue to shift the distribution of possible weather conditions in the coming decade. But not only is the weather itself an uncertainty; how its extremes will impact the electricity system is as well. Weather impacts the electricity system in many ways – it affects the level of electric demand, wind and solar production patterns, thermal plant efficiency, hydrological conditions – and unprecedented extremes may have unanticipated impacts in this complex system.
- **Battery performance:** battery storage resources are in early stages of commercialization at grid scale, and operators have limited experience with them – particularly in climates as harsh as the Southwest. This study relies on an idealized set of assumptions regarding performance, including low outage rates and dispatch that is aligned with times of greatest needs. In reality, performance risks could manifest in numerous ways, including higher-than-expected frequencies of unplanned outages, degradation of output under the extreme temperatures of the desert, or operations that fail to capture the maximum capacity value of the storage. Until engineers, construction, maintenance teams, and operators gain the necessary real-world experience to inform design and operations, planners should be cautious not to overstate their confidence in the performance of nascent technologies in resource adequacy planning.
- **Renewable variability:** as the region transitions to higher levels of wind and solar, weather conditions will have a more direct impact on the availability of generation. While the characteristic production patterns of these resources are generally well-understood, the risk remains that the potential for sudden, large drops in renewable energy output and the potential for extended periods of low renewable energy production.
- **Natural gas fuel security:** the interstate natural gas pipeline system does not operate to the same reliability standards as the electricity system, and fuel deliveries have been interrupted during extreme cold weather events. While this study does not examine these risks quantitatively, the fact that the amount of natural gas generating capacity remains relatively constant throughout the analysis horizon suggests that the same vulnerabilities identified in previous studies – pipeline ruptures and wellhead freeze-offs – will continue to pose risks to regional electric reliability through the coming decade.
- **Timing & development:** meeting regional reliability needs in the next decade will require the addition of thousands of megawatts of new installed capacity each year. The processes surrounding new resource development – including siting and permitting; transmission interconnection studies; competitive solicitations and contract negotiation; regulatory approval processes; and engineering, procurement, and construction – require multiple years and are subject to risks of delay. Failure to bring resources online successfully before they are needed could compromise reliability and create a compounding deficit in a region where loads (and needs) are growing quickly. Utilities, regulators, stakeholders and developers will all share responsibility for working cooperatively to achieve this significant buildout.

Recommendations

This analysis finds that utilities' IRPs in aggregate will position the region to meet regional resource adequacy needs. In the absence of any systemic deficiency that can be traced to current planning conventions, this study concludes that no immediate changes to utility planning practices are needed to maintain reliable electric service.

This finding notwithstanding, utilities should continue to advance their resource adequacy planning practices to take advantage of new information and modeling techniques. These improvements will enable utilities to mitigate the risks identified herein and improve their efforts to balance planning for reliability portfolio alongside affordability and sustainability objectives. Most importantly, utilities should implement the resource adequacy planning "best practices" as identified in this study to the extent practicable, including:

+ **Assess the need for capacity using a probabilistic analysis framework** that captures the range of potential energy demands under an increasingly volatile climate and should update this analysis periodically as new information becomes available or as load shapes change.
+ **Apply an ELCC methodology to assess the capacity value of all resources** in their portfolios on an equitable basis, capturing all of the risks and limitations to resource availability that are well-understood and quantifiable.

Additionally, in recognition of the uncertainties and associated risks identified in this report, utilities should regularly update inputs and assumptions in their resource adequacy planning.

+ **Ensure load forecast captures plausible weather conditions that reflect the best available climate science.** The upward climate trend and associated changes to the distribution of extreme weather conditions will have major implications on the abilities of the utilities' portfolios to supply their needs to an acceptable level of reliability.
+ **Align planning assumptions used to characterize each resource with expectations for performance under extreme heat.** The extreme heat conditions that drive resource adequacy challenges in the Southwest region may also impact the availability of generation, both through increased risk of plant outages and degradation of plant output. Utilities should ensure their planning reflects an understanding of these impacts for all types of resources; to the extent these effects are material, they could represent a correlated risk to resource adequacy.
+ **Gather and incorporate real-world information on performance of emerging technologies.** In the absence of historical data, performance assumptions for nascent technologies like battery storage are often idealized in resource adequacy modeling. Replacing idealized assumptions with real-world performance data will improve utilities' abilities to value the capacity contribution of these resources accurately. A centralized database with records of battery storage outages (such as NERC's Generation Availability Data Set for other technologies) would provide significant value to utilities' planning efforts throughout the country.

Finally, in recognition of the increasing systemic threats posed by catastrophic extreme weather events and common mode failures – both of which are difficult to incorporate into a probabilistic analysis framework – utilities should supplement probabilistic resource adequacy studies with resilience planning studies that examine the potential consequences of extreme weather and/or system contingencies.

1 Introduction

Planning for and maintaining a portfolio of resources capable of providing reliable electric service to its customers has long been a core mission of vertically-integrated electric utilities. Today, reliable electric service is tightly interwoven into the fabric of society, and consumers expect utilities to construct, maintain, and operate a complex system capable of meeting their needs instantly.

Over the course of the past decade, retirements of large quantities of conventional generating resources that utilities have relied upon for years has created an urgent need for significant investment in new resources to ensure reliable electric service can be maintained. Compounding this challenge is the fact that many of the most promising new resources – variable renewables such as solar and wind and, more recently, grid-scale battery storage – operate in ways that are fundamentally different from conventional resources. This has resulted in the urgent need for utilities to update their resource adequacy planning methodologies to ensure that the reliability contributions of these “dispatch-limited” resources are accurately assessed.

The blackouts experienced in California and Texas in 2020-’21 – and several other “near misses” both before and since those events – have brought the topic of resource adequacy to the forefront of the national consciousness, garnering headlines reminiscent of the Western Energy Crisis of 2001 and providing cautionary tales for utilities, regulators, consumers, and other stakeholders. These events have provoked questions and concerns as to whether utilities’ current efforts to plan for resource adequacy are sufficient and whether the challenges facing utilities today and in the future will require new approaches to ensuring reliability.

These concerns are particularly acute for the utilities in the Desert Southwest region of the United States, where – amidst profound changes in regional demographics and electricity demand, the resource mix, and the climate – summer temperatures can routinely reach or exceed 115°F in major population centers and the importance of providing customers with a reliable means of cooling their homes and businesses is difficult to overstate.

But despite the attention it has received, the topic of resource adequacy – and what will be needed to ensure it can be maintained throughout the aforementioned energy transition – remains an esoteric and poorly understood aspect of power system planning. This study represents an effort to clarify the regional dialogue on resource adequacy, highlighting the emerging best practices that will enable a reliable transition to a low-carbon electricity system and using the analytical techniques therein to characterize the challenges facing the Southwest region.

1.1 Study Purpose

The goals of this study are to investigate the resource adequacy challenges facing the Southwest region over the next decade and identify recommendations for utilities, regulators, and other stakeholders to confront those challenges. These goals are achieved through two parallel efforts:

► **Examine the current situation in the Desert Southwest in light of recent challenges in neighboring regions and identify any immediate risks to reliability in the region.**

Unexpected load shedding events that have occurred over the past several years in neighboring regions have prompted questions throughout the industry and across the country as to what vulnerabilities might threaten the reliability of the bulk power system. One of the principal goals of this effort is to provide a high level picture of the current state of resource adequacy in the Southwest – including the risks that could pose a threat to it – as part of a proactive effort to mitigate any of these vulnerabilities.

► **Identify and define best practices for resource adequacy planning that will provide a durable foundation for utilities' efforts to preserve reliability within the region.**

Through a broad literature review and the combined experience of E3 and the region's utilities, with input from an experienced Technical Advisory Committee, this study seeks to define a framework for resource adequacy planning that is well-equipped to serve the region's needs over the next decade as the energy transition continues. Included in the scope of this review are:

- Utilities and RTOs' current planning conventions;
- Independent studies of resource adequacy by consultants, academics, and research institutions;
- Materials produced by reliability entities (NERC & WECC).

► **Demonstrate the techniques and methods highlighted as best practices in an evaluation of the Southwest region's resource adequacy over the next fifteen years.**

Using E3's Renewable Energy Capacity Planning (RECAP) model, this study assesses the region's current and future load-resource balance. Using a loss-of-load-probability modeling approach, the analysis simulates complex portfolios of resources to test the capability of various portfolios to meet an acceptable standard of reliability. By analyzing a range of scenarios and sensitivities, this study examines key uncertainties and their relative impacts on the region's position and likelihood of reliability events.

1.2 Key Trends in the Southwest Region

Due to a far-reaching combination of factors – technological, economic, policy, environmental and societal dynamics – the energy landscape of the Southwest region is in a period of rapid transformation. Many of these changes have direct implications upon the utilities' missions to maintain reliable electric service, and understanding the nature of these changes is essential to planning effectively in the midst of a transition. Six key trends, summarized in Figure 1-1 and discussed further below, are playing out in the Southwest today and will have large and immediate ramifications upon the utilities' efforts to plan for resource adequacy.

Figure 1-1. Six trends that will define the landscape for resource adequacy in the Southwest

Load growth
Expected 2+% load growth resulting from net migration, electrification, and new large customers

Climate change impacts on extreme weather
Increased frequency and intensity of extreme heat events results in more frequent extreme peaks

Planned coal & gas retirements
Announced retirements total 1.4 GW by 2025 and 5 GW by 2033

Increasing risk of sustained drought
Hydroelectric generation facilities susceptible to significant impacts under drought

Rapidly increasing reliance on renewables, storage, and DERs
Resource additions driven by policy, customer preferences, voluntary commitments, and economics

Tightening Western markets
Changes & trends across the broader Western Interconnection reshaping market dynamics

► **Electric load growth – driven by net migration to the region, electrification, and large new customers – will increase the amount of generation needed to ensure reliability.**

Over the next decade, utilities across the region are projecting significant increases in electric demand. Underpinning this projected increase in load is an expectation of rapid economic and population growth. Over the past three years, Phoenix has been one of the fastest growing metropolitan areas in the country,[3] and comparatively low electric rates have attracted electricity-intensive industries to the region. On top of economic and demographic changes, a growing market for electric vehicles is projected to further increase electric demand.

► **Planned retirements of coal and natural gas plants within the region will significantly reduce the capability of the region's existing firm resources.**

The utilities of the Southwest have historically relied significantly on conventional "firm" generation technologies – resources like nuclear, coal, and natural gas that are capable of producing sustained output at their rated capacity – to ensure the reliability of the bulk power system. Due to a combination of factors – aging infrastructure, a changing economic landscape, increasingly stringent clean energy and carbon reduction goals and policies – utilities have made decisions to retire many of these resources. Since 2010, approximately 5,000 MW of natural gas and coal-fired generating capacity has retired within the region, including Four Corners Units 1-3 (560 MW), San Juan Units 2 & 3 (837 MW), and Navajo Units 1-3 (2,250 MW). Over the next five years, utilities plan to decommission an additional 1,400 MW of firm generating capacity; by 2033, this number will increase to roughly 5,000 MW.

While the retirement of aging coal plants will reduce emissions significantly, it will also have a large impact upon the region's resource needs to ensure reliability. Maintaining a comparable level of reliability in spite of the cumulative retirement of 11,500 MW of firm generating capacity in the roughly two decades

[3] https://www.census.gov/data/tables/time-series/demo/popest/2010s-total-metro-and-micro-statistical-areas.html#par_textimage_1139876276

between 2010 and 2033 – nearly 50% of the region's current peak demand – will require utilities to add a significant quantity of new resources to their portfolios.

► **As the portfolio shifts towards renewables, storage and distributed energy resources, planning for resource adequacy becomes increasingly complex.**

The growing presence of solar (both utility-scale and customer sited) and wind resources will soon force planners to look outside of the traditional summer peak period in their efforts to ensure resource adequacy. Increasing penetrations of solar generation will shift the periods of highest "net load" – electric demand minus renewable generation – into the evening, causing the period of greatest reliability risk to occur in the evening after sundown. To account for these effects, planners need methods and tools to quantify resource adequacy needs across all times of day and year – as well as to capture the inherent limitations of variable and energy-limited resources –to ensure reliability.

Increasing amounts of energy storage will similarly pose new challenges. Unlike traditional firm resources, batteries and other "energy-limited" resources are constrained by their "duration": the length of time that they can dispatch at full capacity. In practical terms, this limitation means that such energy-limited resources are well-equipped to meet a portion of a utility's resource adequacy needs; how much will depend on the specific loads and resources in the utility's portfolio.

The transition to a portfolio that is increasingly reliant on energy storage to meet resource adequacy needs poses additional implementation risks for utilities. While the market segment is growing quickly, the operational history of grid-scale battery storage is short – as of the end of 2020, the total installed capacity in United States was 1,650 MW[4] – and its performance under the extreme temperature conditions of the Southwest is an uncertainty. High-profile outages at storage facilities in the past several years serve as warnings that a technology in its commercial infancy may not perform as expected during its initial phases of deployment.

► **Climate change will continue to drive increased frequency and severity of extreme weather events.**

These changes to the region's loads and resources will occur against the backdrop of climatic uncertainty and volatility. While the types of extreme temperature events that typically strain the electricity grid will become more frequent and more severe, the extent and rate of this change will be difficult to quantify. Reliability planning has always required characterizing events at the "tails" of the distribution – that is, the frequency and magnitude of high impact, low frequency events. With limited empirical data and imperfect models of extreme climate impacts, planners face a difficult challenge in quantifying the frequency and magnitude of rare peak load events.

But the implications of climate change upon resource adequacy planning are farther reaching than simply the directional impact that more extreme temperatures will have upon loads – the changing climate will impact resource availability as well. Higher temperatures will result in reductions in generator thermodynamic efficiencies and could lead to stress that leads to increased risk of generator failures;

[4] EIA, 2021. "U.S. large-scale battery storage capacity up 35% in 2020, rapid growth set to continue." https://www.eia.gov/todayinenergy/detail.php?id=49236#.

changing wind, rainfall, and cloud cover patterns will impact the distribution of energy availability from variable resources relative to historical patterns. Extreme weather events, such as the west-wide heat wave of August 2020 and Winter Storm Uri in February 2021, are increasing in frequency and are capable of causing widespread outages.

- **The region faces significant risk of extended droughts, threatening the long-term dependability of some of the region's hydroelectric resources.**

The scarcity of water in the Southwest has shaped and constrained civilization within the region throughout human history. Multiple sectors of the region's economy rely upon an extensive network of water storage, transportation, and delivery infrastructure that stretches from the Rocky Mountains to the Pacific Ocean. The region's electric utilities depend upon water resources for cooling at thermal power plants and for the generation of electricity at hydroelectric facilities, primarily along the Colorado River. These facilities – the Glen Canyon, Hoover, and Parker-Davis Dams – and others supply several publicly owned utilities with meaningful shares of their energy and capacity needs.

Today, due to multiple consecutive years of low precipitation and increasingly high summer temperatures, the Western United States is experiencing historic severe drought conditions. At the beginning of summer 2021, reservoirs across the six-state region of Arizona, California, Colorado, Nevada, New Mexico, and Utah were at an average of 57% of their average seasonal capacity.[5] Projections indicate that these conditions could persist through 2022 and perhaps longer. Sustained drought conditions and low reservoir levels within the region would not only reduce the capabilities of the region's hydroelectric facilities but could threaten their ability to operate altogether. Under certain future scenarios in which reservoir levels drop below specified thresholds, the United States Bureau of Reclamation has indicated that potential closure of generation facilities along the Colorado River may be unavoidable – resulting in a decrease in the region's available hydro supply.

- **More broadly across the Western Interconnection, tightening conditions are increasingly resulting in scarcity conditions in wholesale markets.**

Many of the same dynamics that will bring resource adequacy into sharp relief in the Southwest are playing out in neighboring regions as well. The load-resource balance across the Western Interconnection is tightening, and a period characterized by a comfortable cushion of resources that began in the aftermath of the 2001 Energy Crisis appears to be coming to a close. A shrinking surplus and corresponding tight conditions in energy markets marked by high prices and low liquidity leave little room for error in planning for resource adequacy – the likelihood that a neighbor's surplus may be available to cure a deficiency is shrinking. California's 2020 outages – and a near miss in the Pacific Northwest during the "heat dome" of summer 2021 – highlight the risk of extreme events across the Interconnection.

[5] Mankin JS, Simpson I, Hoell A, Fu R, Lisonbee J, Sheffield A, Barrie D. (2021) NOAA Drought Task Force Report on the 2020–2021 Southwestern U.S. Drought. NOAA Drought Task Force, MAPP, and NIDIS.

1.3 Relationship to Utility IRPs and Other Efforts

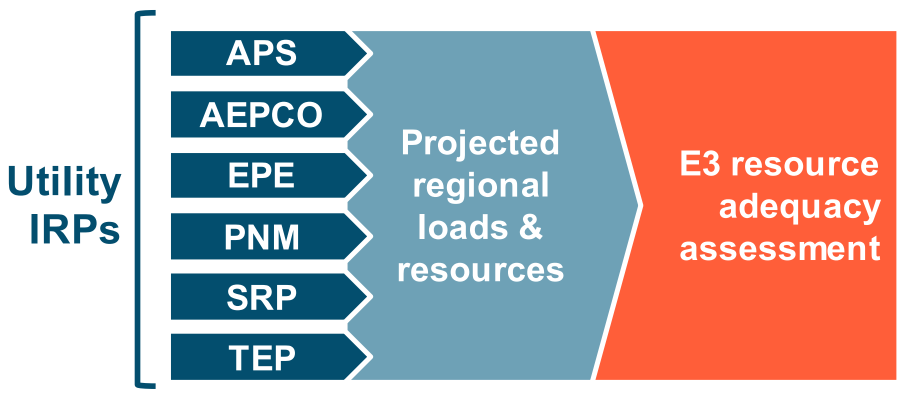
Most utilities within the region conduct periodic Integrated Resource Plans (IRPs), in which they assess short- and long-term needs for new resources and identify a preferred plan for meeting them. While the specific goals and approaches of utilities' IRPs differ, most involve an effort to balance objectives relating to cost, reliability and/or resource adequacy, and environmental impact or sustainability while also complying with relevant regulatory and policy requirements.

This study focuses on resource adequacy but does not examine questions relating to cost or environmental impact. As such, this study does not represent an effort to develop or endorse a regional resource plan; instead, it seeks to answer the following questions relating to resource adequacy at a regional scale based on the utilities' current plans:

+ What is the size of the need for new capacity in the region needed to ensure regional reliability?
+ How effective are different types of resources in meeting this need, considering their specific constraints and limitations?
+ Do the utilities' current resource plans, as reflected by the portfolios produced in their IRPs, position the region to meet resource adequacy needs in the future?

To answer these questions, this study relies heavily on utilities' IRPs as a key source of inputs and assumptions. Utilities' IRPs directly inform the loads and resource portfolios evaluated within this study as illustrated in Figure 1-2.

Figure 1-2. Relationship between utility IRPs and E3's resource adequacy study



While the insights gained from this effort are intended to help utilities, regulators, policymakers, and stakeholders understand the evolving nature of the challenge facing the region, the most appropriate forums for evaluation of utilities' actions in response to these challenges will be through individual utilities' planning and procurement processes. This holds true for multiple reasons:

+ At present, resource adequacy requirements are administered on a utility-by-utility basis. Individual utilities are currently responsible for planning for their own system's resource adequacy – not the region at large – and so the specifics of their own resource adequacy needs and the value that different resources provide to them may differ from the broader region.

- Key uncertainties may change the planning landscape in ways that reshape the needs for new capacity. This study relies on scenario analysis and specific assumptions regarding uncertainties like load growth, hydro conditions and climate conditions; as new information becomes available and some of these uncertainties come into focus, utilities should adjust their plans accordingly. While the methods highlighted herein are robust and the general findings are unlikely to change, a rapidly shifting landscape will require utilities to update plans frequently and proactively.

Western Resource Adequacy Program

Another evolving dynamic with possible future implications for utilities in the Southwest is the Western Resource Adequacy Program (WRAP), [6] a nascent resource adequacy pooling program led by the Northwest Power Pool (NWPP). Originally conceived as a resource adequacy program within the Pacific Northwest, where a shared concern among utilities that overreliance on market purchases and front-office transactions that weren't supported by physical assets might leave the region short on capacity, the potential footprint of the WRAP has grown to include utilities across the Western Interconnection. Participating utilities – including APS and SRP – have currently made non-binding commitments to pursue an implementation phase as they continue to evaluate the benefits of participating in such an effort.

Whether the WRAP moves forward with or without southwestern utilities as participants, the key guiding principle that underpins the effort – that a robust approach to counting capacity that is backed by physical assets – remains a useful guiding tenet for sound resource adequacy planning. While future participation in such a resource adequacy program would surely impact the specific quantification of a utility's resource adequacy requirement and the resources available to it to meet that requirement, the approach used in this study to evaluate regional resource adequacy in the Southwest is largely consistent with the current direction of the WRAP effort. However, this study does not consider or account for the role of any formal future resource adequacy program in meeting the needs of the Southwest region.

1.4 Report Contents

This report is organized as follows:

- **Section 2** presents a survey of the topic of resource adequacy and discusses best practices;
- **Section 3** describes the scope of the technical analysis included in this study;
- **Section 4** summarizes key inputs and assumptions used in the modeling;
- **Section 5** presents key results of the analysis and discusses their implications for utilities within the region;
- **Section 6** examines a number of key risks and uncertainties – both quantitatively and qualitatively – that could affect regional reliability; and
- **Section 7** summarizes the conclusions and recommendations of this study.

[6] https://www.nwpp.org/resources/2021-nwpp-ra-program-detailed-design

2 Resource Adequacy Overview & Best Practices

2.1 What is Resource Adequacy?

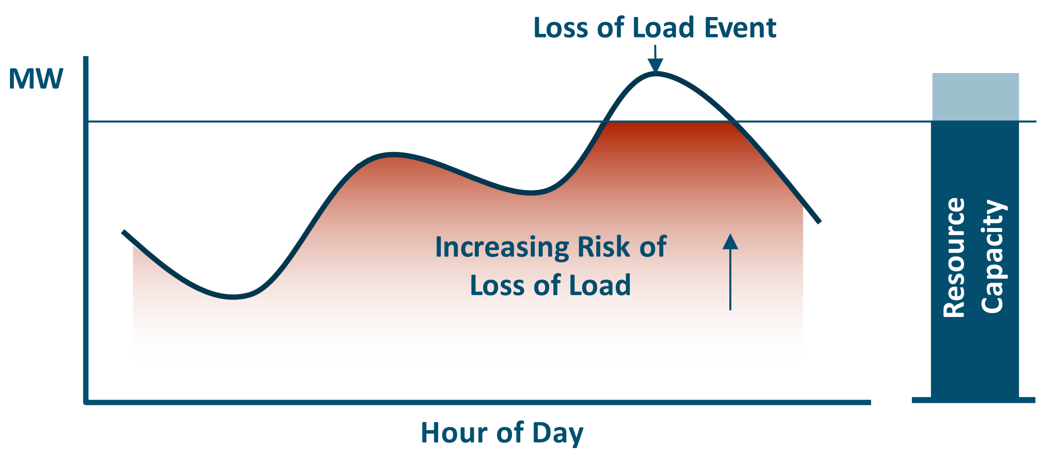
2.1.1 Defining Resource Adequacy

Resource adequacy is the ability of an electric power system to produce sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

NERC Definition of Resource Adequacy

"The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Figure 2-1. Illustration of a loss of load event due to insufficient generation



2.1.2 Relationship to Other Aspects of Reliability

Resource adequacy is one aspect of electric system reliability. Planning an electric system that is capable of providing reliable service requires advance planning of infrastructure from the point of generation to the point of ultimate consumption, spanning the traditional generation, transmission, and distribution functions of a utility. Maintaining reliability during day-to-day operations requires operators to adjust to real-time conditions in order to maintain an instantaneous balance between load and generation throughout the system, including the stability of frequency and voltage. The various functions encompassed by the overarching umbrella are shown in Figure 2-2.

Figure 2-2. Multiple aspects of reliability planning

Distribution System Reliability

Ensure distribution systems are planned to enable delivery of electricity to loads even under severe contingency conditions

Transmission System Reliability

Ensure transmission systems can deliver electricity from generators to distribution systems under steady state and dynamic contingency conditions

Resource Adequacy

Ensure sufficient generation resources are available to meet load with an acceptable level of reliability across a broad range of load conditions while accounting for generator outages, weather impacts on loads & resources, and other constraints on generator availability

Operational Reliability

Maintain system reliability in real-time operations by balancing loads with generation while maintaining sufficient operating reserves to meet flexibility needs and respond to contingencies

Resiliency

Anticipate, respond to, and recover from extreme unexpected events and systemic shocks to any and all parts of the electricity system, including extreme weather events and cyber threats

Further discussion of two of these facets that are closely related to but distinct from resource adequacy planning are explored in further detail below.

Operational Reliability

While the goal of resource adequacy planning is to ensure there is enough physical "steel in the ground" to meet a desired level of reliability, providing reliable service requires a system operator to maintain a real-time balance between supply and demand. This critical function is often described as the need for operational reliability and has, in more recent years, also encompassed questions around the need for flexible resources to ensure this balance can be achieved in spite of an increasingly variable electricity supply. In order to achieve this objective, operators dispatch the portfolio of resources while also maintaining a variety of "operating reserves" (or "ancillary services") to account for forecast error and sub-hourly variability of load and renewables as well as to respond to contingencies.

Naturally, resource adequacy planning and operational reliability intersect: to ensure resource adequacy, a planner must account for the minimum level of operating reserves needed to maintain operating reliability in real time.

Resilience

The traditional definition of resource adequacy focuses on meeting customer loads under "reasonably expected" outages of system elements – and yet, instances when outages have clearly exceeded "reasonable expectation" have led to some of the most notable and impactful reliability events in recent memory. Most recently, during Winter Storm Uri in 2021, widespread unplanned outages due to extreme cold temperatures and cascading failures of gas supply infrastructure left millions in Texas without power for days; at points, the amount of expected capacity unavailable due to unplanned outages reached 34,000 MW, nearly half the system's all time winter peak.[7] Four years earlier, Hurricane Maria destroyed generation, transmission, and distribution electric infrastructure across the island of Puerto Rico, leaving millions without power for months; restoration of electric service for some required nearly a year.[8] The risks posed by these type of hard-to-predict extreme events – known as "High Impact, Low Frequency" (HILF) events – underscore the importance of complementary efforts to consider possibilities beyond the bounds of "reasonable expectation." Such extreme events are the focus of an emerging area of planning often described as "resilience."

In comparison to other aspects of reliability planning, which have well-defined standards and methods for evaluation, definitions of resilience are less precise; however, most definitions focus on the ability of a system to anticipate, absorb, recover from, and adapt to exceptionally rare and disruptive events.[9] The focus on minimization of impacts and recovery from the events are key features of this definition, considering that under some extreme events maintaining reliability is likely impossible. Events typically characterized under the banner of threats to resilience include (1) extreme weather events and natural disasters, particularly those that trigger widespread or cascading failures of electric infrastructure; (2) human-caused threats such as cyberattacks. Because their scope, scale, and probability are not well-known and difficult to quantify, HILF events such as these are not traditionally considered in planning for resource adequacy. Instead, a complementary planning framework that identifies and analyzes event-specific risks and their consequences will become increasingly important, especially considering the growing probability of extreme weather as a result of climate change.

2.1.3 Origins of Modern Resource Adequacy Planning

The foundation for modern resource adequacy planning was established in the middle of the twentieth century, rooted in probabilistic methods for utilities to assess the frequency of extreme load and plant outages. Planners recognized that planning a reliable portfolio of resources would require consideration of both (a) a broad range of possible weather conditions and their associated impacts on load; and (b) the likelihood that power plants may be unavailable at any time due to unplanned outages. To measure the level of reliability risk associated with a specific portfolio, planners engineered probabilistic approaches

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[7] https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[8] Robles, Frances. "Puerto Rico Spent 11 Months Turning the Power Back On. They Finally Got to Her." *New York Times*. https://www.nytimes.com/2018/08/14/us/puerto-rico-electricity-power.html

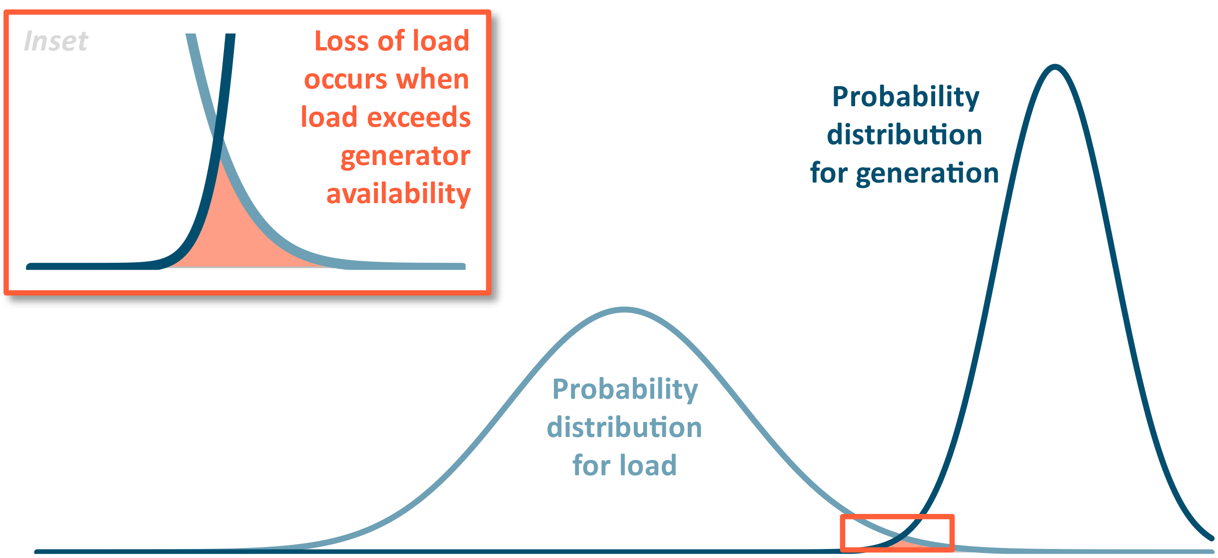
[9] See, for example, https://www.cisa.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf

to assess the likelihood that supply might be insufficient to meet demand. The recognition that a robust approach to resource adequacy would require a probabilistic approach was articulated as early as 1947:

> "A fundamental problem in system planning is the correct determination of reserve capacity. Too low a value means excessive interruption, while too high a value results in excessive costs. The greater the uncertainty regarding the actual reliability of any installation the greater the investment wasted. The complexity of the problem, in general makes it difficult to find an answer to it by rules of thumb. The same complexity, on one side, and good engineering and sound economics, on the other, justify the use of methods of analysis permitting the systematic evaluations of all important factors involved. There are no exact methods available which permit the solution of reserve problems with the same exactness with which, say, circuit problems are solved by applying Ohm's law. However, a systematic attack of them can be made by 'judicious' application of the probability theory."[10]

Designed at the time to focus on the two principal uncertainties that could lead to reliability events – exceptionally high loads and unit outages – these methods compared probability distributions for load and resource availability to assess the chances that load might exceed available supply (see Figure 2-3). These probabilistic approaches reflect the earliest applications of loss-of-load-probability modeling.

Figure 2-3. Illustration of the early conception of loss of load probability modeling

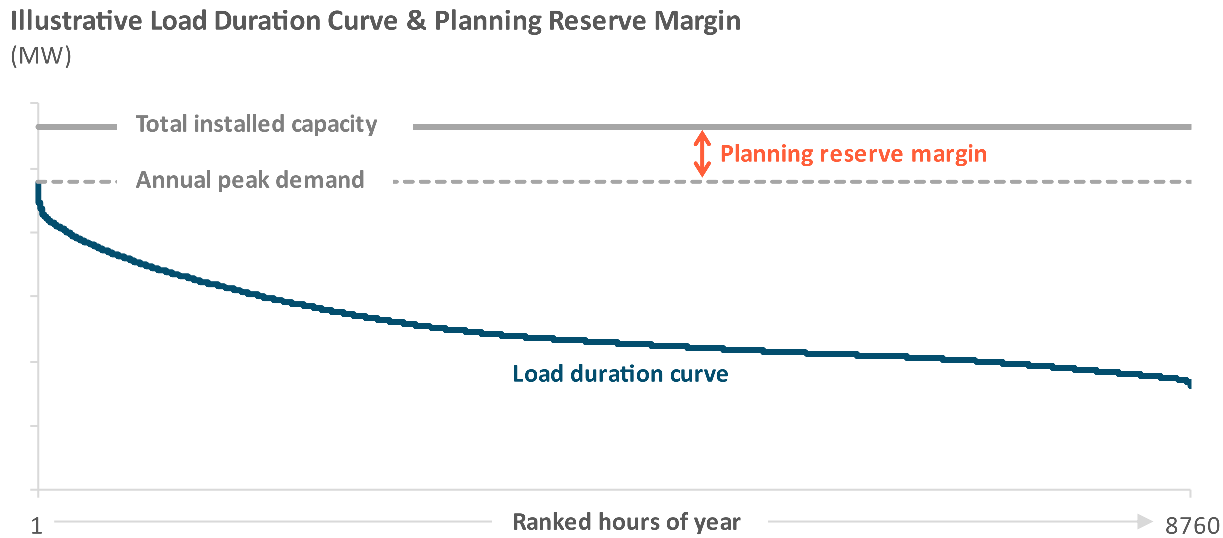


Over time, as the understanding of these risks improved, this probabilistic approach was used to inform simplified heuristic approaches to planning for resource adequacy, the most prevalent of which was the introduction of a **planning reserve margin** (PRM) requirement illustrated in Figure 2-4. The planning reserve margin, defined as a percentage relative to median peak demand, specified the amount of installed capacity above the expected peak demand that would be needed to ensure resource adequacy while accounting for the potential for exceptional extreme loads, resource forced outages, and the operator's need to maintain a margin of operating reserves. Because most systems at the time comprised

[10] Calabrese, G., "Generating reserve capacity determined by the probability method", AIEE Transactions, 66 (1947), pp. 1439-50.

almost exclusively firm resources, ensuring that sufficient installed capacity was available during the period of highest demand also meant that enough resources would be available throughout the year.

Figure 2-4. Illustration of the traditional planning reserve margin heuristic in resource adequacy planning



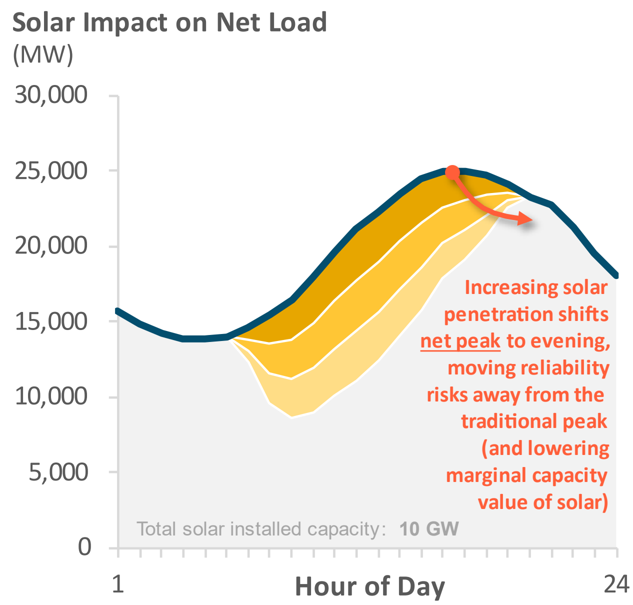
2.2 New Challenges in Resource Adequacy Planning

The heuristic-based approach to planning for resource adequacy using a simple planning reserve margin has, for the most part, been sufficient to ensure resource adequacy of the bulk power system – largely due to the fact that the characteristics of load were well understood and the resources that utilities relied upon were predominantly firm resources that could be called upon when needed. However, a number of fundamental changes to the electricity system have already begun to strain these heuristics, and it is clear that more sophisticated approaches will be needed to ensure reliability in the coming decades. This section discusses how resource adequacy is fundamentally changing, motivating a discussion of how conventional approaches might be adapted for the future.

2.2.1 Increasing Penetrations of Variable & Energy-Limited Resources

One of the trends that has introduced new complexity into resource planning is the increasingly prominent role of "variable" and "energy-limited" resources in utility portfolios. **"Variable"** – typically wind and solar – refers to resources whose output varies hour by hour, usually as a function of meteorological conditions; **"energy-limited"** – for example, hydroelectric generation, energy storage, and demand response – denotes resources with constraints on how long (and sometimes how often) they can generate at full capacity. Due to their constraints and limitations, both categories differ in their impacts on resource adequacy from traditional firm resources. The challenges associated with the transition to a clean energy portfolio have been widely recognized; the resulting changes in the generation mix are described by NERC as "the greatest challenge to reliability"[11] in its *2021 Long Term Resource Assessment*.

Figure 2-5. Increasing levels of solar generation shift the net peak into the evening



The contribution of variable resources towards a system's resource adequacy needs will depend upon the shape of their production profiles. Because their output is often lower than their rated capacity during the periods in which supply is most constrained, the contribution of intermittent resources to resource adequacy is typically lower than their rated capacity. At low penetrations, derates based on simple heuristics may be sufficient to capture this limitation, but as the penetration of variable resources increases, saturation becomes a significant effect. Saturation causes the period in which "net load" – load minus variable resource production – is highest to shift away from gross system peak demand. Figure 2-5, based on load and solar shapes representative of the Southwest region, illustrates this effect. While the period of highest load occurs in the late afternoon during summer, the presence of a large quantity of solar causes the net peak to occur in the evening after the sun has set.

This same effect was clearly apparent during the August 2020 blackouts experienced in California – which occurred during the evening net peak and are further discussed below – and have been well-documented in renewable integration studies. For instance, researchers at National Renewable Energy Laboratory (NREL) recently highlighted the impacts of increasing variable resource penetrations on net load:

> "We found that at these higher penetrations of PV, peak net load hours shift into the evening, or in the case of morning peak hours in the winter, into the earlier morning. We also found a greater frequency of peak net load hours in the winter."[12]

Due to these dynamics, the increasing reliance on variable resources has two significant and related implications for resource adequacy planning. First, as levels of variable resources grow, the periods of greatest resource adequacy risk will shift away from the traditional peak period and into the "net peak." Second, the saturation effect means that the marginal capacity value of variable resources declines as the net peak shifts to periods of lower renewable production (e.g. an evening net peak in solar-heavy systems).

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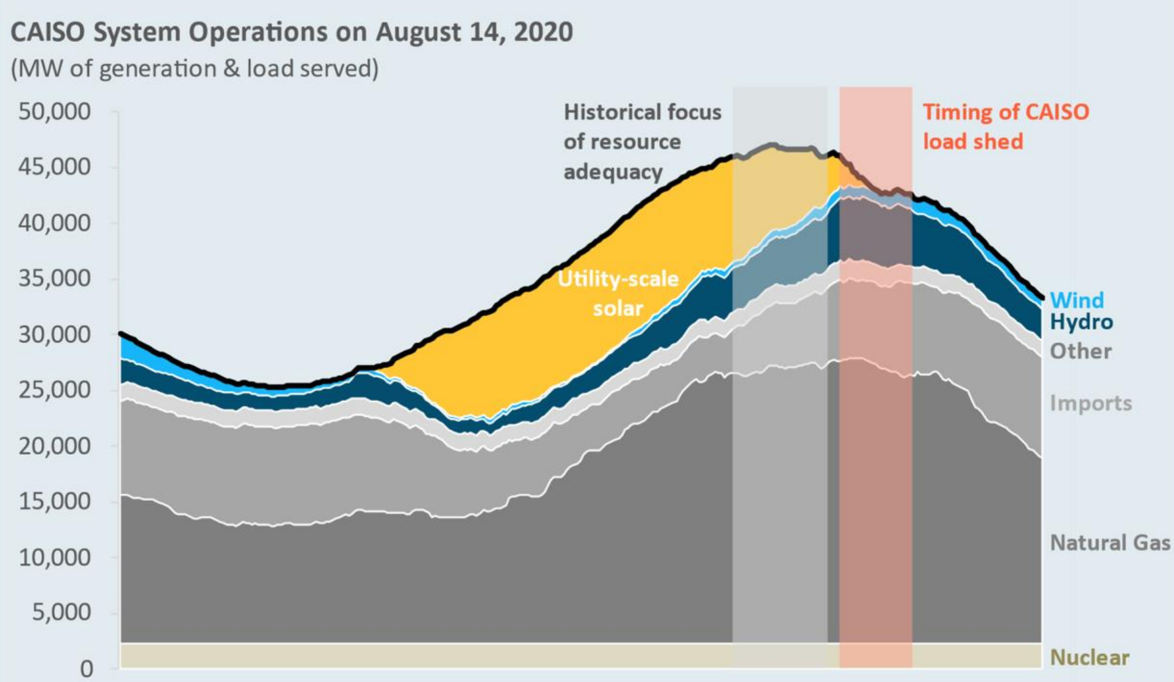
[11] NERC, 2021 Long Term Resource Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[12] Cole, W., D. Greer, J. Ho, and R. Margolis. Considerations for maintaining resource adequacy of electric systems with high penetrations of PV and storage. Applied Energy, Volume 279, 2020, 115795, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2020.115795.

Lessons Learned from California's 2020 Blackouts

California's 2020 blackouts provide the clearest picture of how increasing penetrations of renewable resources can shift the reliability risk outside the traditional peak planning window. The figure below, developed from data published by CAISO, highlights the changing nature of resource adequacy risks under increased penetrations of solar; the period of the day during which load shedding was required occurred after the traditional peak period that has historically been the focus of resource adequacy planning.



In its root cause analysis – cosponsored by the California Public Utilities Commission (CPUC) and California Energy Commission (CEC), CAISO describes how California's resource adequacy planning has not kept pace with the need to plan for this evening net peak:

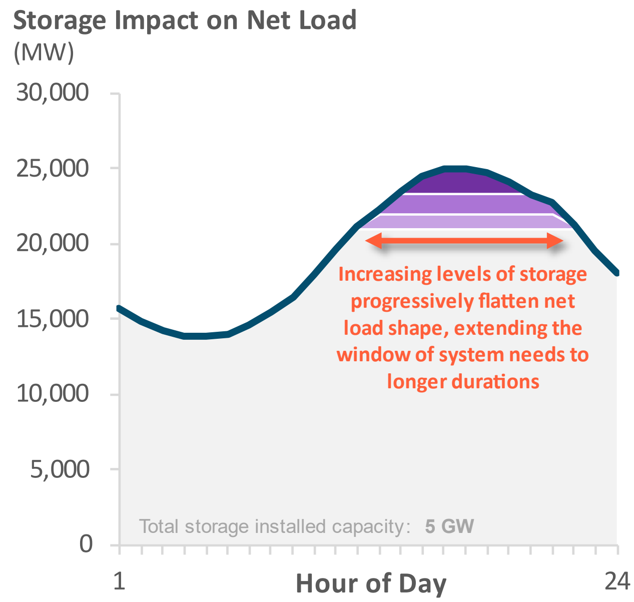
> "In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave."

California's experience provides several generalizable lessons for all jurisdictions in which reliance on renewables and storage is increasing; namely:

- **Planning effectively for resource adequacy will require methods and tools that identify reliability risks that may occur at all times of year – not only during the traditional peak period.**
- **Resource adequacy planning must consider how the potential distribution of weather conditions may change in the future, particularly in light of the risk of increasing probability of extreme**

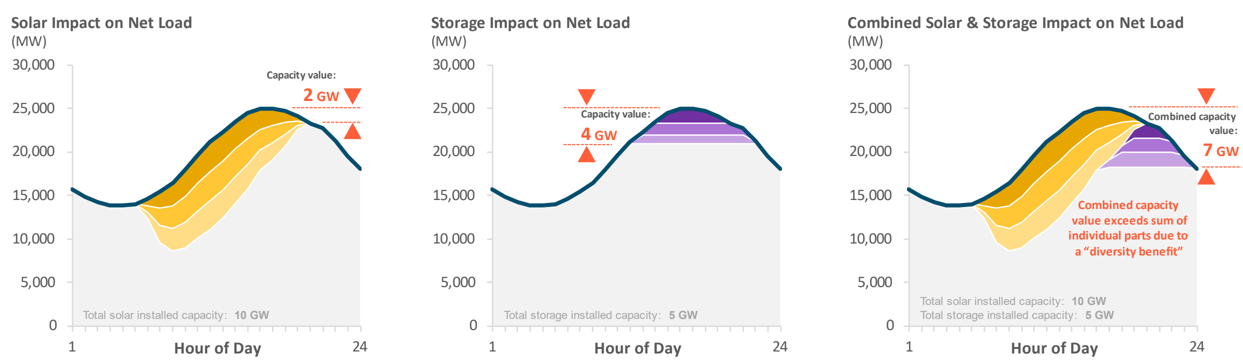
Energy-limited resources – which include energy storage, hydro, and demand response – will also pose novel challenges for planners as their roles in the system grow. Most importantly, their ability to generate for sustained periods is limited; for instance, a four-hour battery can only dispatch at full capacity for four consecutive hours before its state of charge is depleted and it needs to recharge. One of the implications of these constraints is that like variable resources, energy-limited resources also exhibit saturation effects. The capacity contribution of storage declines because, as successive tranches of storage reduce peak demand, the next tranche of storage must dispatch over a longer period to have the same effect. This effect is illustrated in Figure 2-6.

Figure 2-6. Impact of increasing levels of storage on net load shape



The declining marginal value of both variable and energy-limited resources may be partially offset by the presence of interactive effects among different resources, often described as a "diversity benefit": a portfolio of complementary resources can provide a contribution to resource adequacy that exceeds the sum of its individual parts. The nature and size of this effect will vary based on the combination of resources (and can even be negative); Figure 2-7 provides one illustrative example of how a portfolio of solar and storage resources may provide a value that is greater than the sum of its individual components.

Figure 2-7. The "diversity benefit" of solar and storage in their impact on resource adequacy



As the penetrations of renewables, storage, and other non-firm resources continue to grow, so will the prominence of these complex dynamics. One of the implications that follows from these evolving challenges is that the timing of reliability risks will continue to shift to other times of year. Multiple studies have examined the implications of deep decarbonization upon resource adequacy, finding that at very high penetrations of variable generation, reliability risks shift to the winter – even in a summer peaking system – as the most significant challenge to resource adequacy becomes planning for renewable "droughts": extended periods (e.g., multiple consecutive days) of low renewable production. This result has been demonstrated in studies of regions as different as California[13] and New England.[14]

During these periods of sustained low renewable production, the essential role of firm generation that can dispatch at full capacity for prolonged periods is incontrovertible. While the amount of firm resource capacity needed will vary from system to system, the essential role of firm capacity in maintaining resource adequacy – even in electricity systems with very high penetrations of renewables and storage – has been affirmed by many studies, including:

+ *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*, a study completed by E3 in 2019;
+ "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation" (Sepulveda et al.), published by researchers at the Massachusetts Institute of Technology;
+ *Net Zero America*, led by researchers at Princeton University to study pathways to meet a "net zero" carbon target for the United States by 2050;
+ The *Los Angeles 100% Renewable Energy Study*, completed by the NREL to develop plans that would meet the City of Los Angeles' 100% renewable goals; and
+ "Clean Firm Power is the Key to California's Carbon-Free Energy Future," a study co-funded by the Environmental Defense Fund and the Clean Air Task Force.

In many of these studies, the presence of firm resources alongside large penetrations of wind, solar, and storage secures the reliability of the system; while these resources may be rarely needed, their role in ensuring reliability is significant.

2.2.2 Changing Characteristics of Customer Demand

Changing customer preferences and increasing customer engagement also has implications for how utilities plan for resource adequacy. Distributed energy resources (DERs) – including solar, energy storage, and demand response capable devices such as programmable thermostats – are growing in popularity, and their adoption changes how customers consume – and produce and store – electricity. NERC's 2021 LTRA succinctly summarizes the opportunities and complexities resulting from increased deployment of DERs:

> "Distributed energy resources (DER) growth promises both opportunity and risks for reliability. Increased DER penetrations can improve local resilience and offset peak electric demand on the [bulk power system]. However DER can also increase variability and uncertainty in demand and therefore requires careful attention in planning for resource adequacy and energy sufficiency. DERs also increase the complexity of operating the BPS as operators often lack visibility into the effect of the DER on loads. Consequently, there is an immediate concern

[13] E3, 2018. Long-Run Resource Adequacy under Deep Decarbonization Pathways for California. https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf.

[14] E3 and Energy Futures Initiative, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf.

> to ensure that data transfer, models, and information protocols are in place to support BPS planners and operators."[15]

In many ways, the effects of DERs on resource adequacy will parallel the impacts of utility-scale non-firm resources: they are generally variable and/or energy-limited and will be subject to saturation effects and interactive effects. A durable framework for resource adequacy must therefore account for the impacts of customer-sited resources in a manner that accounts for their contributions to resource adequacy consistent with methods applied to utility-scale resources.

Electrification of new end uses will also have implications for future resource adequacy planning. Transportation electrification is already occurring today, but electrification of buildings and industry may follow as the imperative to electrify in pursuit of economy-wide decarbonization intensifies. Growing shares of these new end uses will further add complexity to resource adequacy planning, as the shape of electricity demand will evolve in the future. Transportation load impacts are both uncertain and complex, since they depend on customer driving behavior, charging infrastructure availability (home vs. workplace vs. public), charging speed (high-power rapid charging vs. slower overnight charging), charging costs, and electricity rate design.

Electrification of building loads will further increase resource adequacy needs in deeply decarbonized electric grids due to its outsized impact on winter loads. The addition of load during winter heating seasons further compounds the challenge that planners will have to ensure adequacy during the winter as well as the summer. A recent analysis of wind and solar droughts – defined as week-long anomalies of low wind and solar resource availability – in the Western Interconnection notes that these periods tend to occur during the coldest periods of the year, during which demand for space heating would be highest:

> "Compound wind and solar droughts occurred seasonally when [heating degree days] were largest and the synoptic circulation associated with the compound drought events exacerbates this to a small degree. This means that the electrification of heating could potentially make these compound wind and solar droughts high stress events on a hypothetical underlying energy system (though this may be simultaneously mitigated by global warming)."[16]

But while meeting newly electrified loads will likely require additional resources, the addition of these new loads also offers opportunities for new demand-side flexibility. Electric water heating has already proven itself as a flexible load resource and space heating may provide similar demand response opportunities as space cooling has (one of the primary demand response resources today). Industrial customers often have savvy energy managers dedicated to minimizing energy costs, who are likely to unlock relevant load flexibility opportunities.

[15] NERC, 2021 Long Term Resource Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[16] Brown, Patrick T., et al. "Meteorology and climatology of historical weekly wind and solar power resource droughts over western North America in ERA5." https://link.springer.com/content/pdf/10.1007/s42452-021-04794-z.pdf

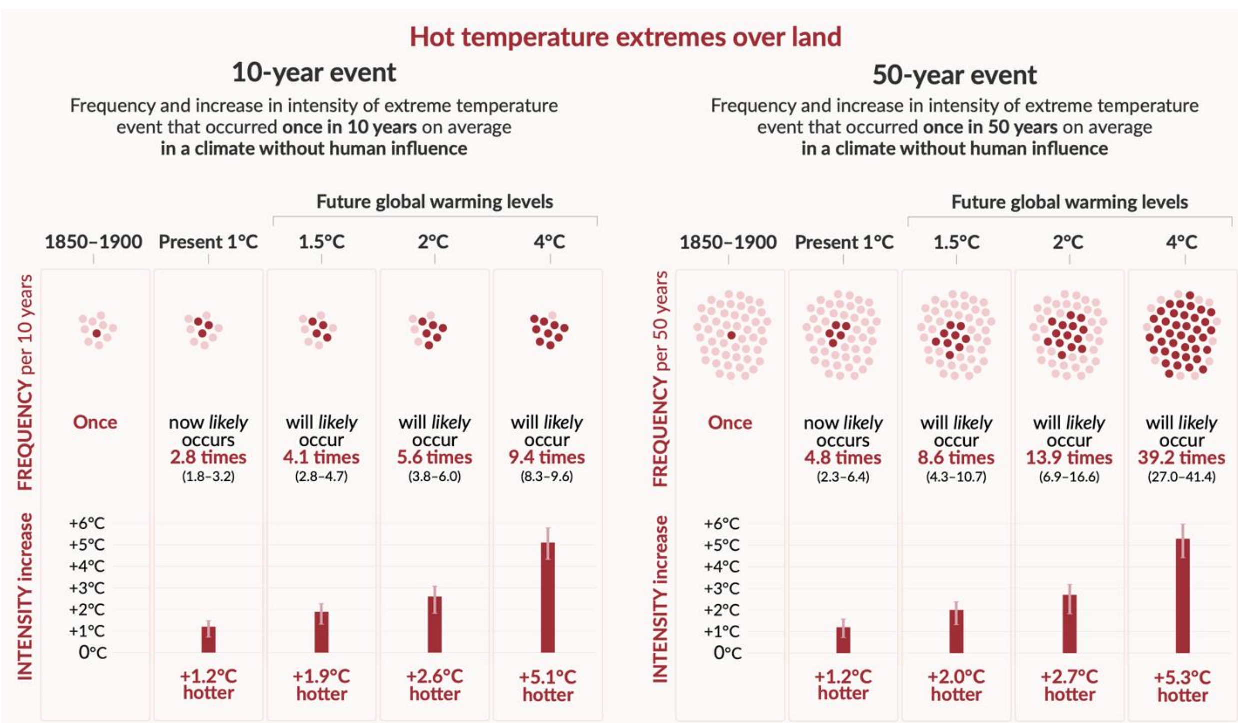
2.2.3 Increasing Climatic & Weather Uncertainty

Concurrent with these changes to customer loads and energy supply, climate change is impacting weather system fundamentals, which has implications for loads and resource availability. Scientific consensus, as captured in the Intergovernmental Panel on Climate Change's (IPCC) *Sixth Assessment Report*, has concluded that "it is unequivocal that human influence has warmed the atmosphere, ocean and land," and that these trends will continue in the future notwithstanding any efforts to mitigate greenhouse gas emissions:

> "Global surface temperature will continue to increase until at least mid-century under all emissions scenarios considered. Global warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO2 and other greenhouse gas emissions occur in the coming decades."[17]

The impacts of these global trends are far-reaching; the effects are expected to include "increases in the intensity and frequency of hot extremes, including heat waves (*very likely*), and heavy precipitation (*high confidence*), as well as agricultural and ecological droughts in some regions (*high confidence*)." Figure 2-8, reproduced from the IPCC *Sixth Assessment Report*, illustrates a range of plausible outcomes on the future impacts of climate change on frequency and severity of extreme heat events.

Figure 2-8. Projected increase in frequency and intensity of extreme weather events under a range of future warming scenarios[18]



[17] IPCC Sixth Assessment Report

[18] Image source: IPCC, "Climate Change 2021: The Physical Science Basis: Summary for Policymakers." https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM.pdf

More concretely, extreme weather events, such as the polar vortex of February 2021 and the Pacific Northwest "heat dome" of June 2021, are causing planners to rethink what conditions should be captured in reliability modeling. Historically, such high-impact, low frequency events have not often been given special attention in resource adequacy modeling datasets, given the limited data available to characterize these events. These recent events highlight that the industry also needs increased scrutiny on how rare, extreme weather events lead to correlated generator outages and how planning exercises focused on resilience may complement resource adequacy planning.

2.2.4 Fuel Security

Reliance on natural gas generation – as well as upstream production, storage, and transportation infrastructure – has increased across the country over the past two decades. The "just-in-time" delivery of fuel exposes natural gas plants to risks of disruption, which may occur due to failures or limitations of upstream pipeline infrastructure or supply constraints resulting from wellhead freeze-offs or other extreme weather events.

The identification of these risks underscores the importance of continued efforts to mitigate risks to electric reliability. NERC's 2021 LTRA offers several recommendations for regulators and policymakers to this effect:

> "With increased reliance on natural gas comes the need to deeply understand natural gas and electric system interdependencies. Improved coordination between natural gas and electricity is required. The lack of that coordination was a major contributor to the devastation in ERCOT during winter storm Uri in 2021. The natural gas system was not built or operated with electric reliability as the first concern. Electric grid planners must understand natural gas system vulnerabilities to assess contingencies and plan for grid reliability. Moreover, NERC believes that the regulatory structure and oversight of natural gas supply for electric generation needs to be rethought to assure reliable fuel supply for electric generation to support the reliable operation of the BPS."[19]

These recommendations highlight the importance of ongoing efforts to characterize the specific risks associated with natural gas infrastructure, which are highly location dependent and can vary dramatically depending on a system's level of reliance on gas generation, what types of transportation service gas generators rely on, the number and size of pipelines serving the region, the availability of natural gas storage, the characteristics of upstream production basins, and a variety of other factors.

2.3 Best Practices for Resource Adequacy Planning

The emerging challenges described above have exposed limitations of the common planning reserve margin heuristic that many utilities have successfully used for decades to ensure resource adequacy. One of the most important implicit assumptions of the traditional planning reserve margin approach has been that resources counted towards the requirement are capable of generating at full capacity at any time of year (absent unexpected plant outages). Neither variable renewables – whose output is typically lower

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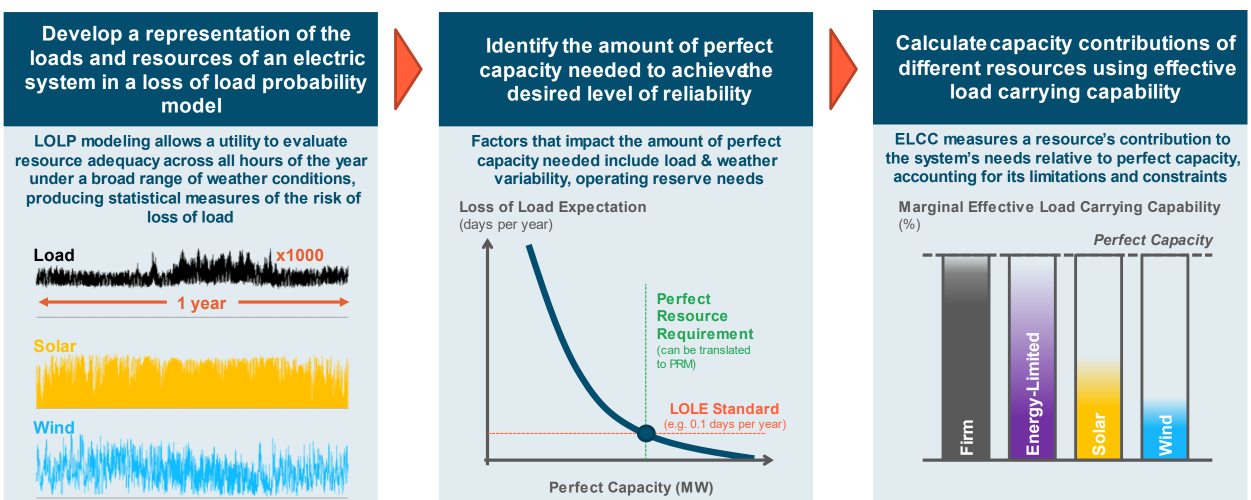
[19] NERC, 2021. 2021 Long-Term Reliability Assessment. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

than installed capacity due to their intermittency – nor energy-limited resources – whose output is limited by the duration of the device – can meet this performance standard. As a result, the planning reserve margin heuristic in which the installed capacity of generation resources is compared against the system peak is no longer sufficient to ensure adequacy.

However, the well-established probabilistic framework for resource adequacy analysis from which these heuristics were originally derived remains a strong foundation for the analysis of resource adequacy in the future. Enabled by an improved understanding of the challenges ahead and innovations in probabilistic methods designed to capture the limitations of variable and energy-limited resources, utilities and program administrators have taken important steps to modernize their toolkits and approaches to resource adequacy planning. The necessity of a framework for resource adequacy analysis that is strongly rooted in the fundamentals of probabilistic analysis is increasingly widely supported by practitioners and thought leaders in the industry.

Based on a survey of the methods currently in use throughout the industry as well as recommendations offered by regulators and thought leaders, this section defines a concrete set of best practices for future resource adequacy planning, summarized in Figure 2-9. These best practices reflect an aspirational approach to resource adequacy planning; that is, while many utilities and program administrators' current approaches to planning are generally aligned with the methods and principles articulated below, most also have room to improve.

Figure 2-9. Three foundational pillars underpinning a robust approach to resource adequacy



At its most foundational level, a robust framework for resource adequacy requires three components:

1. Development of a **loss-of-load-probability model** that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather conditions to identify periods in which an electricity system is vulnerable to reliability risks;
2. Derivation of a **total capacity requirement** that reflects the amount of "perfect capacity" needed to achieve an acceptable standard of reliability; and

3. Application of an **effective load carrying capability (ELCC)** accounting framework to measure the contribution of each resource (or portfolio of resources) towards the total capacity requirement.

While a loss of load probability model alone can provide the most robust and detailed view of a specific portfolio, there are multiple reasons to pair it with a simplified capacity accounting framework for resource adequacy, namely:

- **Computational burden:** the computational burden of each simulation – which requires evaluation of thousands of years' worth of conditions – means that relying solely on LOLP analysis is not a practical approach to resource adequacy planning; the use of a capacity accounting framework calibrated by an LOLP model allows planners to evaluate the impacts of decisions upon resource adequacy without needing to rerun costly simulations.
- **Ease of understanding & accessibility:** the statistical metrics output by LOLP models are difficult to contextualize; a capacity accounting framework provides all parties with a more concrete framework in which different resources' contributions can be evaluated.

Is the Planning Reserve Margin "Too Focused on the Peak?"

The argument that the planning reserve margin is focused exclusively on meeting peak demand – and is therefore not well-suited for use in a highly renewable, highly storage dependent electricity system – has become a common criticism of current resource adequacy methods. The extent to which this criticism is valid depends on the accounting conventions with which resources are counted towards that requirement. If resources are counted only during their ability to generate during the peak window – a common heuristic that has been applied to variable resources in the past – then the PRM accounting framework will indeed fail to capture the complex dynamics occur the risk of loss of load shifts to other periods of the day (and year). If, on the other hand, resources are counted towards the requirement using an approach that measures their value to the system relative to a perfect benchmark unit, a PRM accounting construct can continue to capture the emerging complexities of a grid in transition – even as the risk of loss of load migrates outside of the peak period. Under this paradigm, the PRM requirement is not a requirement for capacity during the peak window, but is instead a requirement for equivalent firm capacity – which is exactly what effective load carrying capability is designed to measure. When paired with the right methods for counting capacity, the PRM remains a valid construct for capacity planning.

2.3.1 Developing a Loss of Load Probability Model

Among industry experts and utility planners, there is a broad and growing consensus that probabilistic methods that allow for analysis of resource adequacy across all periods of the year – not just during the system peak – will be essential. The importance of a probabilistic approach to resource adequacy assessments has been emphasized by a number of notable groups, including:

- NERC, which has published technical reports on best practices in modeling approaches and data collection and has hosted a biannual Probabilistic Analysis Forum;
- The Western Electricity Coordinating Council (WECC), whose recent study of resource adequacy in the Western Interconnection recommends that "[p]lanning entities and their regulatory authorities should consider moving away from a fixed planning reserve margin to a probabilistically determined margin"[20];
- The IEEE Resource Adequacy Working Group, wherein industry experts meet annually to share learnings and findings related to probabilistic analysis of resource adequacy; and
- The Energy Systems Integrations Group (ESIG), whose recent whitepaper *Redefining Resource Adequacy for Modern Power Systems* introduced six philosophically grounded principles for resource adequacy analysis that emphasize the importance of probabilistic methods.

Among its six guiding principles for resource adequacy, ESIG's Redefining Resource Adequacy Task Force includes a direct endorsement that "[c]hronological operations must be modeled across many weather years" elaborating:

> "Modeling sequential grid operations is critical to capture the whole picture: the variability of wind and solar resources along with the energy limitations of storage and load flexibility. Chronological stochastic analysis is thus increasingly important, simulating a full hour-to-hour dispatch of the system's resources for an entire year of operation across many different weather patterns, load profiles, and random outage draws."[21]

The consensus behind the importance of probabilistic methods is further underscored by their increasingly prevalent use within the industry, from RTOs & ISOs charged with managing resource adequacy in the context of organized markets to utilities that manage their own portfolios to ensure reliability for their customers.

The need for a probabilistic approach to resource adequacy implicates a type of analysis known as **"Loss of Load Probability" (LOLP)** modeling. LOLP models employ a variety of statistical and simulation techniques to compare forecast electricity demand with available generation resources under a very broad range of conditions that accounts for variability of weather, loads, renewable generation; unforced outages; and a number of other constraints and stressors that could impact the ability of a portfolio of generators to meet loads.

Modern LOLP models typically simulate the performance of the electricity system on an hourly basis over the course of the entire year. Within an LOLP analysis, these annual simulations are repeated hundreds or thousands of times – each iteration stochastically capturing a different combination of weather conditions and outages – to provide a robust assessment of the probability of tail events that drive resource adequacy challenges.

The simulation of conditions across a broad range of conditions allows LOLP models to calculate a variety of statistical measures of resource adequacy. These metrics provide insights into the expected frequency,

[20] WECC, *The Western Assessment of Resource Adequacy Report*, https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf

[21] Energy Systems Integration Group (ESIG), Redefining Resource Adequacy for Modern Power Systems, https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf

size, and duration of expected unserved energy events based on the results of the simulation of thousands of years. Table 2-1 lists the typical metrics produced by LOLP models; among these, the most commonly discussed is **Loss of Load Expectation (LOLE)**, defined by NERC as "the expected number of days per time period (usually a year) for which the available generation capacity is insufficient to serve the demand at least once per day."[22]

Table 2-1. Typical metrics produced by LOLP models

Metric	Type (Units)	Definition
Loss of Load Expectation (LOLE)	**Frequency** (days per year)	Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity
Loss of Load Events (LOLEV)	**Frequency** (events per year)	Average number of loss of load events per year, of any duration or magnitude, due to system demand exceeding available generating capacity
Expected Unserved Energy (EUE)	**Magnitude** (MWh per year)	Average total quantity of unserved energy (MWh) over a year due to system demand exceeding available generating capacity
Normalized EUE (nEUE)	**Magnitude** (parts per million)	Expected unserved energy normalized by total expected annual demand
Loss of Load Hours (LOLH)	**Duration** (hours per year)	Average number of hours per year with loss of load due to system demand exceeding available generating capacity

Best Practices for LOLP Modeling

Loss of load probability modeling has advanced significantly from its roots in the mid-1900s and today utilities and resource adequacy program administrators use both commercial and in-house software solutions to simulate the system under a broad range of conditions. Most LOLP models in use in the industry today use a Monte Carlo approach to simulate load and resource availability on an hourly, chronological basis to capture the inherent complexities of today's systems. While each model has unique qualities and idiosyncrasies, it is nonetheless useful to define a minimum standard for functionality needed to address the complex issues discussed above. These include the needs to:

+ **Capture a diverse range of load conditions that account for potential extreme weather.** Electricity demand should reflect expected range of possible weather variability across many years. Where possible, these distributions should incorporate information on the potential localized impacts of climate change on frequency and intensity of extreme weather.

[22] NERC, "Probabilistic Adequacy and Measures: Technical Reference Report." https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

+ **Simulate generator outages stochastically.** Generator outages should be modeled stochastically for all resources. If historical data suggests a possible risk of correlated outages among generators, this information should be included in simulation of outages.
+ **Incorporate realistic profiles for renewable generation that capture correlation with load.** Production patterns for variable resources (e.g. solar and wind) should incorporate multiple years of meteorological data and reflect underlying correlations with electricity demand.
+ **Simulate dispatch of energy-limited resources on a time-sequential basis.** A chronological approach to simulation of loads and resources should be used to incorporate constraints of energy-limited resources (e.g. energy storage, demand response, and hydro).

Convolution vs. Simulation Techniques in Loss of Load Probability Modeling

Loss of load probability models typically fall into two categories: "convolution" approaches, which use a mathematical technique known as convolution to combine distributions for load and resource availability to compute direct numerical metrics, and "simulation" approaches, which simulate the actual operations of the system on an hour-to-hour basis over many possible years. While convolution approaches offer much shorter computing time, simulation methods have quickly become the gold standard for modern LOLP modeling. Simulation techniques offer multiple advantages over convolution techniques in their ability to represent complex systems with chronological dependencies; most important among these is the ability to represent the dispatch of energy-limited resources like energy storage in a way that is not possible using the convolution approach. For this reason, the convolution approach to LOLP modeling is no longer widely used.

Data Challenges & Uncertainties

Like most technical analyses, curating a robust, quality-controlled set of inputs and assumptions is critical to meaningful analysis of resource adequacy; at the same time, because LOLP models seek to capture exceptionally rare events in a probabilistic manner, developing data sets that appropriately represent the magnitude and frequency of "tail" events (and correlations among them) is a marked challenge. In *Reliability Evaluation of Power Systems*, author Roy Billinton recognizes this challenge: "Meaningful reliability data are not always easy to obtain, and there is often a marked degree of uncertainty associated with the required input."

The challenges in gathering data and the corresponding uncertainties have compounded since this observation was written nearly thirty years ago. Practitioners of LOLP modeling must be cogently aware of the inherent limitations in their datasets and the implications they may have upon their evaluations. Among the most significant data challenges facing planners today:

+ **Distributions of extreme weather events:** as greenhouse gas emissions continue to push global climate into new territory, the level of climatic uncertainty is unprecedented. While planners have long relied on extended samples of historical weather data to inform probability distributions of tail weather events; the assumption that historical conditions provide an accurate representation of the future is no longer appropriate. As climate change continues to alter weather system fundamentals, planners must be cautious to consider a broad plausible range of conditions that may extend beyond historical distributions. How to incorporate future projections of downscaled climate impacts into LOLP modeling is an emerging area of research within the field.

- **Renewable production data:** the adequacy of a system will depend, in part, on how renewables perform during rare extreme load events. For many renewable facilities, little to no historical data is available that can be used directly for this purpose. For this reason, the use of simulated renewable profiles, which rely on historical meteorological data as inputs into simulations of wind and solar plant performance, is common practice. However, modelers must understand that this introduces a risk of simulated profiles deviating from actual performance due to simulation error and a variety of real-world factors that may not be captured in the simulation.
- **Performance assumptions for emerging technologies:** generation technologies are quickly advancing, and utilities are presented with new resource options to meet their needs that would not have been available a decade ago. This trend is likely to continue, as research, development, and deployment will continue to bring new technologies into the market. While these advances offer long-term promise, planners should also take caution in assumptions made regarding the performance of new resources with limited operational history at commercial scale. Especially during early years of commercialization, new technologies may not perform as expected.
- **Correlations among unit outages:** the assumption that forced outages of generators can be modeled as independent, uncorrelated events is common practice in LOLP modeling; to the extent that underlying factors like weather patterns and fuel supply issues may affect outages at multiple plants simultaneously, a correlated risk that is not often captured may exist. While evidence of this type of correlated relationship exists, it is typically highly geographically specific and difficult to generalize. While capturing these types of relationships would improve the rigorousness of reliability modeling, the limited availability of robust data sets that might inform this type of approach remains a real barrier.

2.3.2 Identifying Total Capacity Needs

The first step in a resource adequacy assessment is “need determination”: an evaluation of how much supply is needed to maintain resource adequacy while accounting for the probabilities of extreme weather events and operators’ needs to maintain operating reserves. This section describes how an LOLP model can be used to establish a robust requirement for need that is directly informed by probabilistic standards for resource adequacy.

2.3.2.1 Selecting a Reliability Standard

While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. NERC and WECC publish information and projections about resource adequacy but have no formal governing role. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so.

"One Day in Ten Years"

While there is no single mandatory standard defined for resource adequacy, many utilities today rely on some interpretation of the "one day in ten years" rule of thumb. While this rule of thumb has been interpreted in a number of different ways, the most common interpretation relies on the statistical metric Loss of Load Expectation (LOLE). Under this interpretation, an electricity system with an LOLE of 0.1 days per year meets the one day in ten year standard. While other statistical standards are used in some jurisdictions, the LOLE standard of 0.1 days per year remains the most common throughout the industry. Table 2-2 lists the reliability standards used by select utilities and jurisdictions across North America.

Comparing LOLE = 0.1 days per year and LOLH = 2.4 hours per year

A less common interpretation of the "one day in ten year standard" relies on Loss of Load Hours and allows for up to 24 hours of loss of load over a ten year period (or 2.4 hours of lost load per year). The difference between an LOLH standard of 2.4 hours per year and an LOLE standard of 0.1 days per year is nuanced but significant: LOLE measures the expected number of days on which an unserved energy event occurs – regardless of duration – whereas LOLH measures the expected number of hours of unserved energy. Many unserved energy events that result from insufficient generating capability last several hours - implying that a system planned to meet an LOLH standard of 2.4 hours per year will likely experience a loss of load expectation above 0.1 days per year. As a result, the LOLH standard of 2.4 hours per year is generally less stringent than the LOLE standard of 0.1 days per year.

Alternative Standards

While the LOLE standard of 0.1 days per year remains the most common probabilistic standard across North America and is generally accepted as industry standard, it has been criticized by some observers who suggest that alternative standards should be considered. The two most common critiques of the LOLE standard are:

+ **Some critics argue that an LOLE standard of 0.1 days per year is arbitrary.** While the "one day in ten year" standard is meant to ensure loss of load events are exceedingly rare, its critics highlight the lack of a clear basis to justify this specific standard. As described in one study: "this reliability criterion was developed in the middle of the 20th century, with limited rationale as to how the criterion was selected, and with limited evaluation of the costs and benefits of reliability."[23]
+ **Some critics highlight that the LOLE metric focuses only on frequency.** A second criticism of the LOLE standard is that its focus on frequency inherently ignores the potential magnitude and duration of loss of load events, information that may also be useful in the determination of what level of reliability to plan for.

These criticisms notwithstanding, the "one day in ten years" standard has gained nearly universal adoption among utilities and program administrators across North America. Proper application of the "one day in ten years" standard should be sufficient to achieve its intended objective – to ensure that

[23] Stenclik, D. and M. Goggin. "Resource Adequacy for a Clean Energy Grid: Technical Analysis." https://acore.org/wp-content/uploads/2021/11/RA-for-a-Clean-Energy-Grid_Technical-Analysis.pdf.

reliability events due to insufficient supply occur exceedingly rarely. However, its common use does not make it sacrosanct, and as the transition to an energy-limited system continues, alternative standards – in particular, those focused on expected unserved energy or other measures that account for the size of events – should be investigated.

Table 2-2. Probabilistic standards for resource adequacy for select utilities & jurisdictions

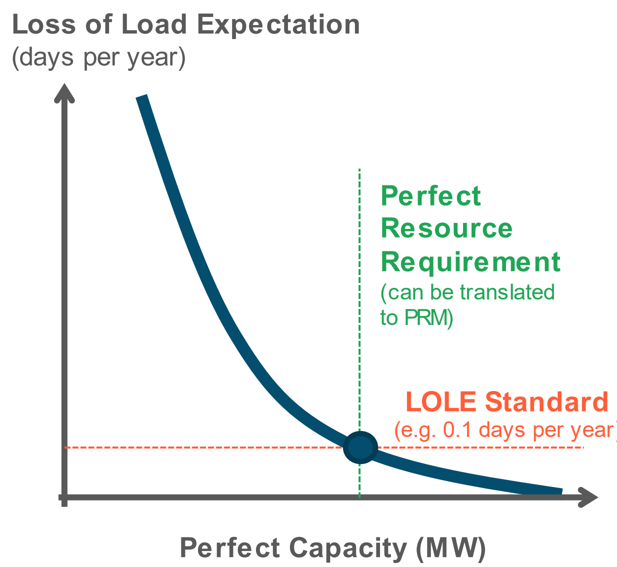
Category	Utility/Jurisdiction	Metric	Current Standard
Southwest Utilities	Arizona Public Service Co	LOLE	0.1 days per year
	El Paso Electric Co[1]	LOLE	0.2 days per year
	Public Service Company of New Mexico[2]	LOLE	0.2 days per year
	Salt River Project	LOLH	2.4 hours per year
	Tucson Electric Co[3]	PRM	15%
Other Western Utilities	Avista Corporation	aLOLP[4]	5% per year
	Idaho Power Company	LOLE	0.1 days per year
	Nevada Power Company	LOLE	0.1 days per year
	Portland General Electric	LOLH	2.4 hours per year
	Public Service Company of Colorado	LOLE	0.1 days per year
	Puget Sound Energy	aLOLP[4]	5% per year
Other Utilities	Duke Energy Carolinas	LOLE	0.1 days per year
	Duke Energy Progress	LOLE	0.1 days per year
	Florida Power & Light	LOLE	0.1 days per year
	Georgia Power Co	LOLE	0.1 days per year
	Nova Scotia Power, Inc.	LOLE	0.1 days per year
RTOs & Resource Adequacy Programs	ISO New England	LOLE	0.2/0.1/0.01 days/yr
	Midcontinent ISO	LOLE	0.1 days per year
	New York ISO	LOLE	0.1 days per year
	PJM	LOLE	0.1 days per year
	Southwest Power Pool	LOLE	0.1 days per year
	Western Resource Adequacy Program[5]	LOLE	0.1 days per year

1 El Paso Electric's 2021 IRP assumed a transition from a standard of 0.2 days per year to 0.1 days per year by 2030
2 In recent filings, PNM has indicated its intention to move towards the more common industry standard of 0.1 days per year
3 TEP's current planning reserve margin is not directly tied to a probabilistic resource adequacy requirement
4 Annual loss of load probability (aLOLP) is a metric used predominantly in the Northwest that measures the probability of at least one reliability event occurring over the course of the year.
5 While the Western Resource Adequacy Program is still in conceptual phases of implementation, its sponsors have indicated an intent to rely on a standard of 0.1 days per year

2.3.2.2 Calculating the Planning Reserve Margin Requirement

Once an appropriate statistical standard is determined, a utility can identify the amount of "perfect capacity" needed to meet a desired standard for resource adequacy using a loss of load probability model. Increasing quantities of perfect capacity will result in an increasingly reliable system; Figure 2-10 illustrates the characteristic functional form of the relationship between the quantity of perfect capacity and LOLE. The asymmetry of this curve has significant implications for resource adequacy planning: a increasing capacity shortfall below the desired standard quickly escalates to rapid degradation of the portfolio's reliability.

Figure 2-10. Illustrative relationship between perfect capacity and loss of load expectation



The denomination of a requirement in terms of the total amount of *perfect capacity* needed to achieve a specified standard is a notable characteristic of this approach and a small change from the traditional planning reserve margin requirement – in which the reserve margin reflected the amount of *installed capacity* needed to achieve the desired level of adequacy. Expressing the requirement in terms of perfect capacity enables a more consistent treatment of various resources through capacity accreditation using an ELCC approach.

Dividing this total requirement for perfect capacity by the system's expected peak demand yields the planning reserve margin requirement. Because a planning reserve margin based on absolute perfect capacity needs depends only on the system's load and operating reserve needs and is independent of its resource mix, this relative ratio will remain stable over time so long as no substantial changes to the load shape occur.

2.3.3 Calculating Effective Load Carrying Capability

Effective load carrying capability (ELCC), increasingly used by utilities and RTOs throughout North America, is the preferred metric to measure the capacity contribution of different resources towards the system's resource adequacy needs. The ELCC is a robust measure of a resource's contribution to a utility's reliability standard, defined as the quantity of "perfect" capacity that could be replaced or avoided by a resource while providing equivalent system reliability. For example, if a 100 MW resource has an ELCC of 50 MW, that means that that this resource could displace the need for 50 MW of perfect capacity with no impact on system reliability. The ELCC can also be expressed in percentage terms by dividing by the nameplate capacity; in this example, the ELCC of the resource would be 50 percent.

The strength of an ELCC-based approach lies in the use of a common benchmark ("perfect capacity") against which the impacts of all resources can be measured. In "Redefining Resource Adequacy for Modern Power Systems", the authors espouse the principal that "there is no such thing as perfect capacity," elaborating: "Future resource adequacy analysis should explicitly recognize that all resources have limitations based on weather-dependence, potential for outages, flexibility constraints, and common points of failure."[24] By measuring each resource's impact on system reliability relative to this common benchmark, an ELCC-based approach is well-suited to achieve this aspirational level of technological agnosticism, placing all resources on a level playing field that accounts for the various constraints and limits on their availability.

2.3.3.1 Origins & Theoretical Basis

The earliest applications of the ELCC approach introduced the method to measure the capacity value of conventional resources in a manner that differentiated individual plants' contributions to resource adequacy based on their size and forced outage rates.[25] Since this time, the method has been extended to a much broader set of technologies with more varied constraints on availability, including wind, solar, storage, hydro, and demand response.

The calculation of ELCC is tied directly to LOLP modeling. Calculating the ELCC for a resource (or portfolio of resources) occurs through a three-step process. First, a representation of a "base" portfolio of resources and loads is developed in an LOLP model and "tuned" via the addition of perfect capacity[26] to meet a desired reliability target (e.g., LOLE of 0.1 days per year). Next, the resource of interest is added to the portfolio, resulting in an improvement in reliability. Finally, through an iterative process, perfect capacity is removed until the original level of reliability is restored. In this process, the amount of perfect capacity removed is equal to the resource's ELCC. This process is illustrated in Figure 2-11.

Figure 2-11. Methodology to calculate ELCC from an LOLP model

Due to its derivation directly from LOLP modeling, the ELCC metric intrinsically captures a broad range of factors that may limit a resource's ability to contribute to the system's reliability need, incorporating the effects of any correlations (positive or negative) that might exist between energy-limited resource production and load. As described in a 2008 NREL study surveying methods used to determine wind capacity value:

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[24] Redefining Resource Adequacy Task Force. 2021. Redefining Resource Adequacy for Modern Power Systems. Reston, VA: Energy Systems Integration Group. https://www.esig.energy/reports-briefs.

[25] Garver, L. L. (1966) "Effective Load-Carrying Capability of Generating Units." IEEE Transactions on Power Apparatus and Systems. Vol PAS-85.

[26] In some approaches, ELCC is calculated using a tuning process that adds or removes flat load – rather than perfect capacity. These two methods should not yield substantially different results.

> "ELCC decomposes the individual generator's contribution to system reliability. It can discriminate among generators with differing levels of reliability, size, and on-peak vs. off-peak delivery. Plants that are consistently able to deliver during periods of high demand have a high ELCC, and less reliable plants have a lower ELCC. For variable generators such as wind, the method can discriminate between wind regimes that consistently deliver during high-risk periods, sometimes deliver during high-risk periods, or never deliver during high-risk periods. In fact, ELCC can provide for a continuum of capacity values over these potential outcomes."[27]

Thus, while the ELCC method considers a resource's performance across all hours and under all possible conditions, the resulting ELCC will reflect a measure of the resource's contribution to system needs during the periods in which supply is most constrained.

2.3.3.2 Current Applications and Uses

Administrators of capacity markets and resource adequacy programs are likewise turning to ELCC as a means of adapting market-based frameworks to accommodate the challenges of variable and energy-limited resources. Several markets already rely on ELCC for accreditation of at least one technology, and most others are in the process of transitioning towards ELCC or are actively considering its implementation. Most recently, PJM secured FERC's approval for tariff updates needed to implement an ELCC-based accreditation framework for renewables, energy-limited resources, and hybrid resources. FERC's decision approving the tariff noted that the application of ELCC would better allow the PJM market to ensure resource adequacy:

> "…we find that the ELCC framework, which is grounded in a probabilistic LOLE analysis, offers a significant improvement over the 10-hour rule and PJM's other existing provisions for determining the capacity value of ELCC Resources, and will ensure that the PJM capacity market continues to deliver a level of reliability commensurate with the prevailing industry standard (i.e., an LOLE of 0.1, or 1 day of outage per 10 years)."

Table 2-3 summarizes the current status of implementation of ELCC across the various organized capacity markets and resource adequacy programs throughout North America. Two markets currently rely on ELCC for accreditation of at least one technology; two are in the process of implementation; and two are currently evaluating the proposition of implementing ELCC.

While most uses of ELCC to date have focused on renewables (and, to a lesser extent, energy storage), the conceptual framework is broadly applicable to all resource types. No resource is truly perfect, but all resources' contribution to reliability can be measured using an ELCC framework. The broad application of ELCC for resource accreditation across all types of resources provides the strongest foundation for a robust resource adequacy planning framework into the future, as it would treat all resources on an equitable basis.

[27] Milligan, M. and K. Porter. "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation." https://www.nrel.gov/docs/fy08osti/43433.pdf.

Table 2-3. Current applications of ELCC across organized markets & resource adequacy programs

Region	Utility/Jurisdiction	Application of ELCC
Southwest Utilities	Arizona Public Service Co	• Relied on expected production during top 90 load hours to measure capacity value in 2020 IRP
	El Paso Electric Co	• Currently using ELCC methods to value capacity from all resources, including renewables, storage, and firm in 2021 IRP
	Public Service Company of New Mexico	• Currently using ELCC methods to measure capacity contributions from variable & energy limited resources; UCAP accreditation for thermal resources in 2020 IRP
	Salt River Project	• Currently using ELCC methods to value renewables and storage resources
	Tucson Electric Co	• Relied on expected production during time of system peak to measure capacity value in 2020 IRP
Other Western Utilities	Avista Corporation	• Used an ELCC methodology to measure capacity contribution of all resource options
	Idaho Power Company	• Implemented an ELCC methodology to assign credits to solar, wind, demand response, storage, and solar plus storage in 2021 IRP
	Nevada Power Company	• Began studying ELCC for solar in 2017; adopted ELCC method for valuing renewables in Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan filed in 2020
	Portland General Electric	• Currently using ELCC methods to measure capacity value of renewables and storage resources in IRP planning
	Public Service Company of Colorado	• Currently using on ELCC methods to measure capacity contributions of wind, solar, and storage in IRP planning
	Puget Sound Energy	• Adopted ELCC methodology to measure value of all new resource options, including renewables, storage, and demand response beginning in 2017 IRP
RTOs & Resource Adequacy Programs	CPUC	• Adopted an ELCC approach in the CPUC Resource Adequacy program for wind and solar accreditation in 2015[28] • Used ELCC for wind, solar, and storage in IRP proceeding, including for compliance with California's recent procurement order for 11.5 GW
	ISO-NE	• Began assessing and discussing ELCC methodologies with stakeholders in 2020 to see how it could be used to quantify renewable and energy storage resource contribution
	MISO	• Implemented ELCC accreditation for wind generation in 2011

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Region	Utility/Jurisdiction	Application of ELCC
	NYISO	• Currently exploring reforms to capacity accreditation, including ELCC and "marginal reliability improvement" (MRI, a closely related concept); considering application of reforms to all types of generation resources
	PJM	• Received FERC approval in July 2021 for tariff revisions adopting an ELCC accreditation methodology for variable resources, duration limited resources, and hybrid resources
	SPP	• Received Supply Adequacy Working Group (SAWG) approval to use ELCC as guiding principle for accreditation of renewable and storage resources in 2019; transition will become effective in 2023 summer
	WRAP	• Proposed implementation of an ELCC accreditation approach for wind, solar, and run-of-river hydro

Comparing "Unforced Capacity" (UCAP) and Effective Load Carrying Capability (ELCC)

Multiple resource adequacy programs and capacity markets use "Unforced Capacity" (UCAP) to assign capacity credits to firm resources – where UCAP is calculated as the rated capacity derated by the forced outage rate. This approach is designed to recognize that no resource is perfect in its availability and to distinguish among resources with different outage probabilities. In many instances, the simple UCAP calculation of a firm resource will serve as a reasonable approximation of its ELCC. In some cases, such as small systems where the size of a single unit outage may have an outsized impact on reliability or where multiple generators are subject to a common mode failure, this approximation may break down and the ELCC of a firm resource may be lower than its UCAP.

2.3.3.3 Advantages of an ELCC Approach

The ELCC method has emerged as the preferred metric for capacity accounting to meet resource adequacy for multiple reasons:

- **ELCC is determined directly from the LOLP analysis utilized to calculate the total capacity need, reflecting a resource's contribution to a specified statistical standard and leaving no need for heuristics or other inferior accreditation metrics**

As a derivative of the LOLP modeling used to calculate need, ELCC captures a resource's performance across a wide range of system conditions. This ensures that the estimation of capacity contributions is robust across a wide distribution of potential outcomes, including infrequent tail events (e.g., higher load and lower renewable output than expected) that are the primary drivers of reliability challenges.

- **ELCC provides a technology-agnostic framework for the measurement of resources' reliability contributions, thereby offering an economically efficient signal for new resource investment**

This approach therefore puts all resources on a level playing field and ensures equitable treatment among them. A resource with an ELCC of 1 MW has the same contribution toward resource adequacy, regardless of whether that capacity contribution comes from solar PV, wind, energy storage, natural gas, or coal.

- **ELCC directly accounts for complex interactive effects between different resources in the portfolio, including saturation effects that occur when the penetration of a single resource increases and the diversity benefit attendant to complementary resources**

ELCC naturally accounts for both the saturation effects that occur as a particular resource type is added to the system in increasing quantities and the interactive effects between different types of technologies to provide a more complete and accurate measurement of the contribution of dispatch-limited resources to the system. These dynamics are crucial to consider in planning a reliable system that relies heavily on renewable and storage resources.

2.3.3.4 Applying ELCC as a Vertically Integrated Utility

In practice, the same qualities that make ELCC the most robust method for measuring capacity contribution also make it a complex method to apply. The simplest example of an application of ELCC is in the context of a vertically integrated utility that is responsible for meeting its own resource adequacy requirement with a single portfolio of resources. For such a utility, accrediting capacity value to individual resources is not strictly necessary—what matters is whether the utility's total portfolio meets its total needs. In this case, the application of ELCC may reasonably rely directly on the two "measurable" ELCC values: portfolio and marginal. Both are directly useful to the utility:

+ To assess whether a given combination of resources is sufficient to meet a utility's resource needs, the **portfolio (or average) ELCC** provides a measure of the combined capacity contribution of all resources in its portfolio.
+ To evaluate potential resource additions, the **marginal ELCC** for each resource provides a measure of how much that resource will increase the total ELCC of the utility' s portfolio, offering a means of comparing the relative capacity value of resource alternatives to identify the least-cost resource among a discrete set of options.

Within this framework, once a new resource has been procured, it is no longer necessary for the utility to ascribe a capacity value to that specific resource, and it may be treated as part of the portfolio ELCC calculation. Together, these two constructs can allow a utility to simultaneously ensure the reliability of its existing portfolio of resources and make economically efficient decisions in the procurement of new capacity resources to meet incremental need.

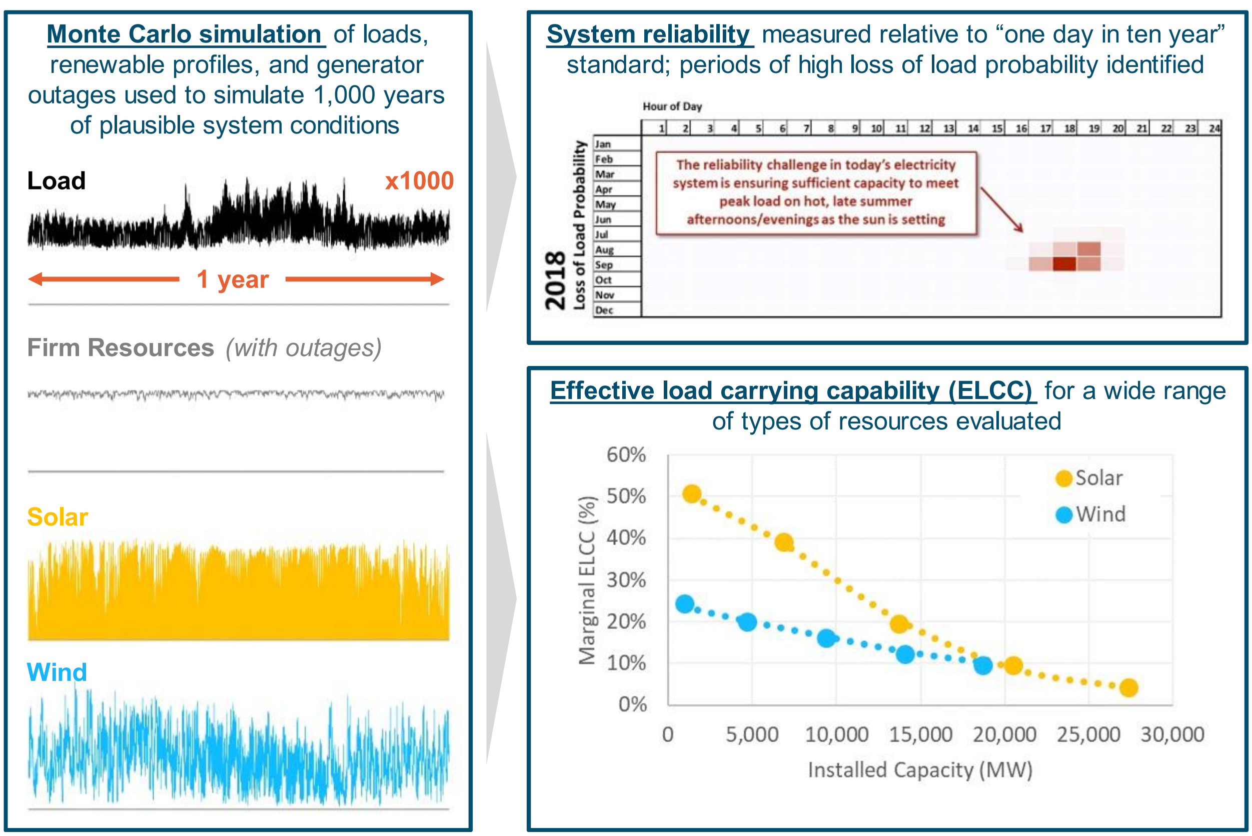
3 Analytical Framework

3.1 RECAP Methodology

This study relies upon E3's **Renewable Energy Capacity Planning (RECAP)** model, a proprietary loss-of-load probability (LOLP) model, to determine the regional capacity need and resource capacity value for the Southwest. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven variability of electric demand, forced outages of power plants, the natural variability and energy-limitation of resources such as hydro, wind and solar, and operating constraints for resources like storage and demand response. These simulations determine the likelihood and magnitude of loss of load – energy demand that cannot be served – and provide the basis for calculating the PRM.

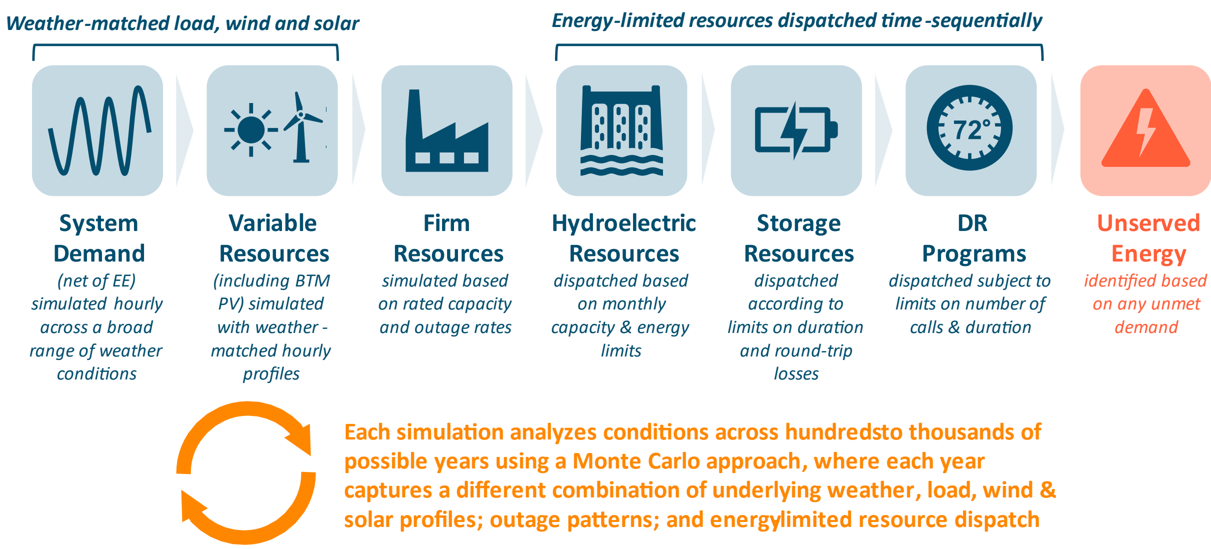
This section includes a short description of the RECAP simulation methodology; additional detail is provided in Technical Appendix B.

Figure 3-1. Overview of E3's RECAP model



RECAP simulates hundreds of "years" of potential conditions using stochastic techniques to appropriately capture the risk of tail events (e.g., higher load and lower renewable output than expected).[29] RECAP simulates balance between system demand and available generation in each hour of a year and repeats this process hundreds of times with different system conditions (see Figure 3-2). This ensures that RECAP captures a wide distribution of potential outcomes, including unlikely tail events that may not occur in a "typical" year. Relevant correlations are preserved within the model to ensure linkage among load, weather, and renewable generation conditions based on historical observations.

Figure 3-2. RECAP simulation methodology



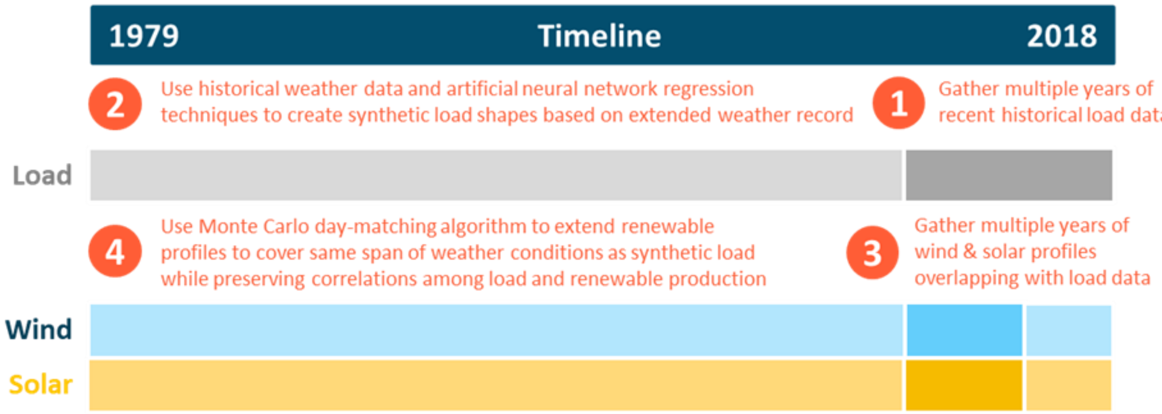
Through this simulation process, RECAP calculates the usual suite of statistical metrics produced in LOLP modeling to characterize the frequency, magnitude, and duration of potential reliability events (LOLE, LOLH, EUE, and others). Additionally, RECAP can be used to calculate common "derivative" metrics, including the planning reserve margin and ELCCs for individual resources.

Treatment of Load and Renewable Data

Typically, hourly load and renewable data is available only for a limited sample of years. To reflect a more extensive weather record, RECAP uses a combination of statistical techniques to simulate plausible load and renewable profiles under a broader sample of weather conditions, relying on meteorological data that spans multiple decades. The multi-year profiles of load and renewable are "reshuffled" through Monte Carlo simulation to produce hundreds of total simulation years so that the expected values of various metrics can be calculated. The typical high-level steps in this process are illustrated in Figure 3-3.

[29] In this approach, each "year" represents a different realization of conditions on the Southwest region over the course of a year. Factors that will vary from one "year" to the next include underlying weather patterns – and by extension, load and renewable profiles – power plant outages, and energy-limited resource dispatch.

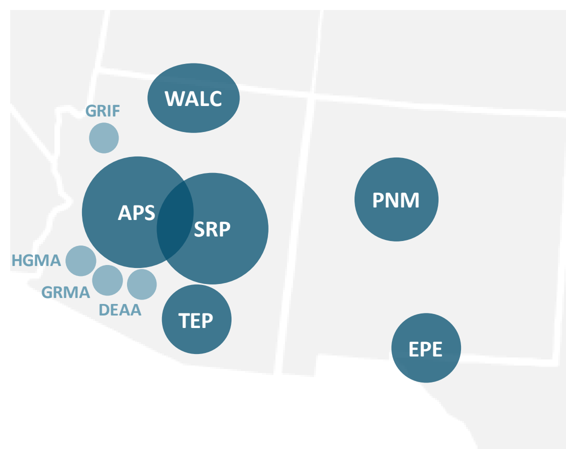
Figure 3-3. Process to extend load and renewable profiles



3.2 Geographic Footprint

The resource adequacy analysis in this study focuses on the ability to meet loads in the Southwest region within the Western Interconnection, defined to include Arizona, New Mexico, and a portion of northwest Texas. These loads span six balancing authorities (shown in Figure 3-4): APS, EPE, PNM, SRP, TEP, and WALC; the loads of these balancing authorities are included in their entirety.[30] The generation resources against which these loads are compared include all resources physically located within the region – including those in the four "generation-only" balancing authorities in the region–with some specific adjustments to account for interregional plant ownership and offtaker agreements:

Figure 3-4. Study geographic footprint



+ Resources physically located in the Southwest that are owned by or under contract to utilities outside the region are excluded from the study. This includes the share of the Palo Verde Nuclear Generating Station owned by California utilities, shares of federal hydro projects under long-term contract to utilities in California and Nevada, and wind and solar projects in the region whose offtakers are located in California.

[30] In other words, the loads considered in this study reflect the entirety of the Southwest region, not just those of the sponsoring utilities.

+ Resources owned by utilities in the Southwest that are located outside of this footprint are included within the scope. This applies to several coal plants with partial ownership attributed to Southwest utilities.

This analysis does not reflect transmission constraints within or between balancing authorities of the Southwest. To the extent that transmission congestion impedes delivery of generation resources to load, the level of regional resource adequacy observed in this study could be overstated. While most utilities secure transmission to enable delivery of their own resources to their own loads at the times of highest need, intraregional constraints – especially between utility systems – could serve as an impediment to harnessing the full benefits of load and resource diversity at a regional scale as characterized in this study.

Additionally, this analysis assumes that utilities within the region are able to co-optimize resource dispatch across the entire footprint to maximize the value of resources to the regional grid – rather than in their individual portfolios. While an active bilateral wholesale market and the presence of the Western Energy Imbalance Market (EIM) provide opportunities for sharing of resources in real time today, there may be instances where the assumption of perfect coordination overstates the likely real-world level of coordination. For example, this study assumes demand response program calls are optimized to meet regional reliability; in reality, utilities are likely to reserve their calls for when their own systems are most constrained. Similarly, this study dispatches all energy storage resources to meet regional needs; in reality, utility operators may be more conservative in their sharing of an energy-limited resource if they anticipate a risk to reliability on their own system. In the absence of a more formal capacity pooling arrangement among utilities, the assumption that resources will be dispatched for regional needs rather than utility needs may overstate the region's reliability.

Finally, it is important to emphasize that while this study provides some perspective on expected directional reliability outcomes across the region, the administration of resource adequacy remains the responsibility of individual utilities under the jurisdiction of their respective regulators. Accordingly, while the trends and dynamics explored herein are broadly applicable to the region as a whole, individual utilities' resource adequacy needs – and their options to meet those needs with different types of resources – may reasonably vary from those identified here.

3.3 Scenarios & Sensitivities

To assess the future resource adequacy needs in the region, this study analyzes four primary scenarios that reflect two different resource portfolios at two specific snapshots in time. The two resource portfolios examined in this study are:

+ **Existing and committed resources**, which includes existing resources (except those planning to retire) and resources with signed contracts under development by utilities; analyzing this portfolio provides a perspective on whether and how much additional resource capacity will be needed to ensure regional resource adequacy.
+ **Utility IRP portfolios**, which includes all resources in the scenario described above in addition to generic future resources identified by the regional utilities' current plans; the purpose of this scenario is to assess the degree to which utilities' current plans will position the region favorably to meet regional resource adequacy needs.

These two portfolios are examined in two specific future years, each chosen to reflect a future milestone in which the regional portfolio will have experienced significant changes: 2025 (after retirement of San Juan and Cholla coal plants) and 2033 (after retirement of Coronado, Four Corners, and Springerville Units 1 & 2). Additionally, an analysis of the region's historical resource adequacy position in 2021 is included as a useful historical benchmark. Figure 3-5 summarizes the scenarios considered in this study.

Figure 3-5. Four scenarios (and a historical benchmark) evaluated in this study

	Time Horizon		
Resource Portfolios	**2021**	**2025**	**2033**
Existing & Committed Resources	0	1	2
Utility IRP Portfolios		3	4

In addition to analyzing these scenarios under a set of specified "Base Case" assumptions, this study also investigates key uncertainties and risks through sensitivity analysis on these scenarios. Sensitivity analysis helps highlight the range of impact associated with each risk and helps to bound this studies' assessment of regional resource adequacy. The sensitivities explored in this study include variations on hydro conditions, plant outage rates, battery storage performance, "peakiness" of loads, regional market interactions, and a "summer stress" sensitivity designed to highlight a worst-case combination of sensitivities.

Table 3-1 lists the specific sensitivities explored in this study. Not all sensitivities are studied under all scenarios due to their limited impacts in certain cases; for example, the battery storage performance sensitivities focus on the IRP portfolios, where the penetration of battery storage is large enough for these uncertainties to have a material impact on regional resource adequacy.

Table 3-1. Sensitivities considered within this study

Category	ID	Description	2025 E&C	2025 IRP	2033 E&C	2033 IRP
Hydro Conditions	A	WAPA “critical” hydro conditions	●	●	●	●
	B	WAPA “dry” hydro conditions	●	●	●	●
Gas Outages	C	Higher Outage Rate (2x)	●	●	●	●
Increased Peak Demand	D	Median peak scaled to 1-in-5	●	●	●	●
	E	Median peak scaled to 1-in-10			●	●
Battery Storage Performance	F	Storage outage rate increased to 10%		●		●
	G	Storage outage rate increased to 10%		●		●
	H	Storage duration derated by 10%		●		●
	I	Storage duration derated by 20%		●		●
	J	Combine F & H		●		●
	K	Combine G & I		●		●
Regional Support	L	Include shaped imports from CA & NV	●	●	●	●
Timing	M	One-year delay for new additions		●		
“Summer Stress”	N	Combine A, C, D, G, J		●		●

4 Inputs & Assumptions

Developing a representation of the Southwest region in an LOLP model requires a broad range of inputs to characterize the range of expected system demands and the capabilities of the available generating resources. The inputs and assumptions needed for this analysis are summarized in Table 4-1.

Table 4-1. Summary of key inputs to RECAP analysis

Module	Inputs Needed
System Demand	• Annual energy demand • Annual 1-in-2 peak demand • Hourly profiles corresponding to a wide range of weather conditions (20+ years) • Minimum operating reserve requirements
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	• Monthly capacity rating by resource • Forced outage rate by resource • Maintenance profile by resource
Variable Resources *(e.g. wind, solar)*	• Installed capacity by resource • Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Hydroelectric Resources	• Installed capacity by resource • Monthly/daily energy budgets across a range of plausible hydro conditions • Minimum output levels by month/day • Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	• Installed capacity by resource • Duration by resource • Charging & discharging efficiency by resource • Paired variable resource (for hybrids) • Interconnection configuration & rating (for hybrids)
Demand Response Resources	• Expected load impact by program • Limits on number of program calls (per year or per month) • Duration of calls

The remainder of this chapter describes the key inputs and assumptions used to simulate future resource adequacy of the Southwest region. Additional detail on data and assumptions used to simulate the loads and resources of the Southwest region is provided in Technical Appendix A.

4.1 Electricity Demand

The projections of annual demand for energy and hourly system peak are developed from load forecasts provided by each of the Southwest utilities. These numbers are derived from the most recent load forecast developed in their IRPs (or comparable planning processes). Each utility's forecast reflects their projection of future loads based on expected demographic trends, changes in consumption patterns, etc. Forecasts reflect the impact of various load modifiers, including:

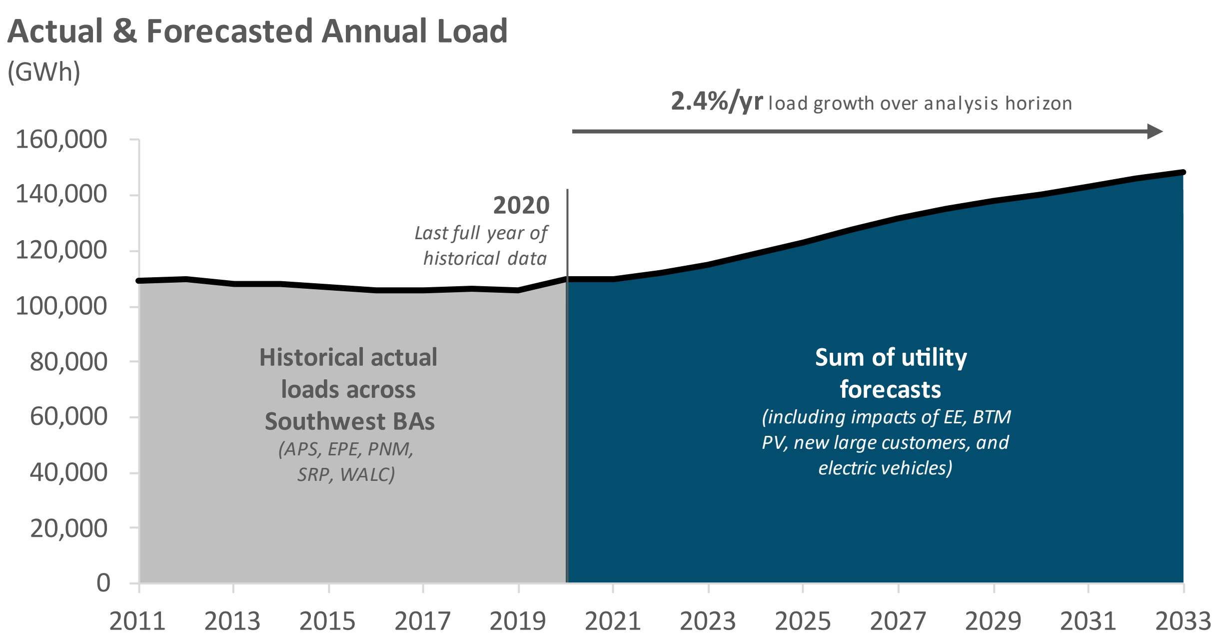
- **Energy efficiency**, which offsets approximately 12% of utilities' total projected load growth between 2021 and 2033;
- **Behind-the-meter solar PV**, which is projected to grow from roughly 2,200 MW-ac in 2021 to 3,000 MW-ac in 2025 and 4,300 MW-ac in 2033;
- **Increasing electric vehicle load** based on utilities' latest projections of electric vehicle adoption in their respective service territories; and
- **New large customer loads** that capture the impacts of future economic development associated with data centers.

All load modifiers – both their levels and shapes – are treated as static inputs for the purposes of this analysis to align with utility planning assumptions. This assumption notwithstanding, demand-side management resources may contribute to regional resource adequacy needs beyond the levels considered in this study. For example:

- Incremental energy efficiency that reduces load during periods of the greatest resource adequacy risks; or
- Programs to manage the shape of electric vehicle charging that shift consumption away from the periods of greatest reliability risk to other times of day.

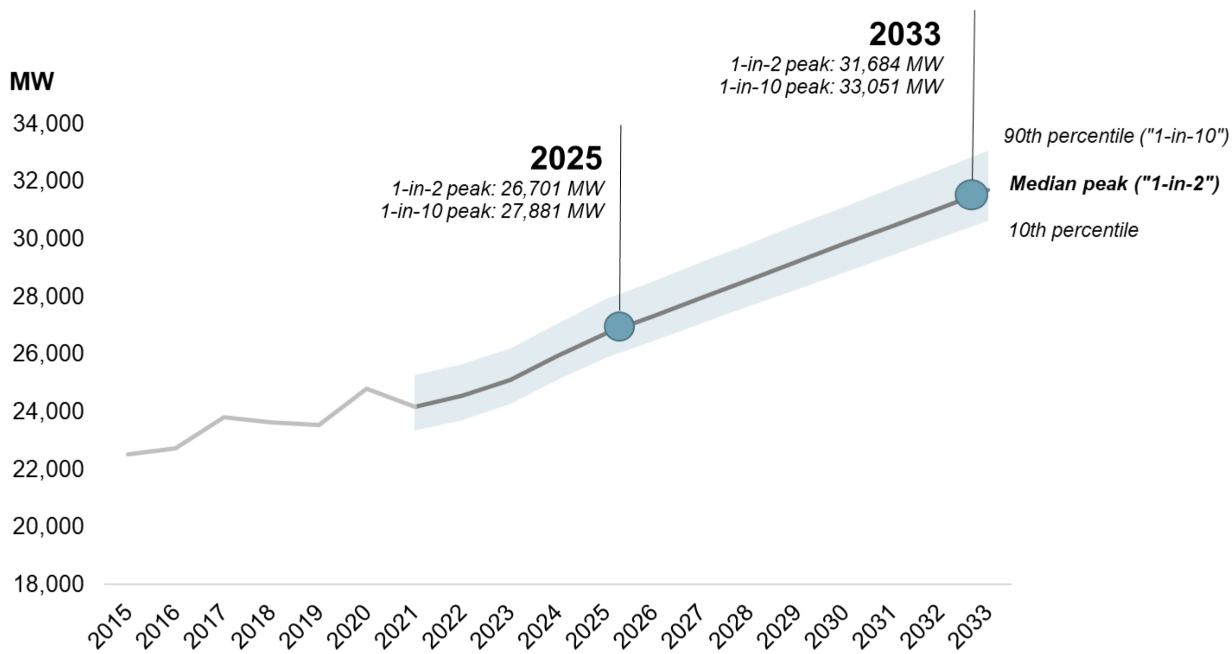
The resulting forecast for annual energy demand across the region based on utilities' forecasts is shown in Figure 4-1. Over the twelve year study period, annual load is forecast to grow at an average rate of 2.4% per year. Significant portions of this growth are driven by new large customers, transportation electrification, and demographic changes.

Figure 4-1. Annual energy demand projection developed from utility forecasts



The regional coincident peak demand is determined through an aggregation of load shape components (base load, EV load, large customer load, and BTM PV). Peak demand, like total energy demand, is projected to grow over the forecast period in each of the BA territories, driven by expected population growth, electric vehicle adoption, and new large commercial loads. The projection of peak demand developed based on utilities' forecasts is shown Figure 4-2, which shows both the peak demand under a typical weather year (the "1-in-2" or "median" peak) as well as an expected peak demand under a more extreme weather condition that might occur only once in a ten year period (the "1-in-10" peak). These are reported here for informational purposes; in the simulations, each year's peak is sampled from a broad distribution of possible weather conditions.

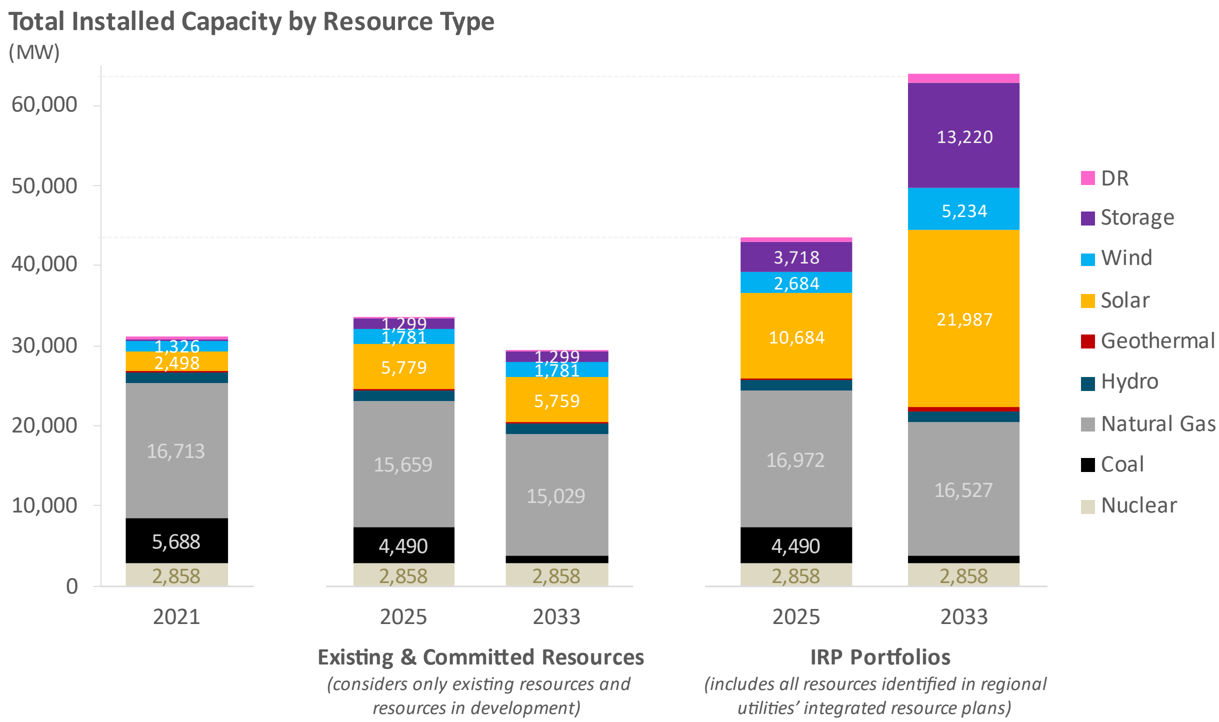
Figure 4-2. Southwest coincident peak load forecast developed from utility forecasts



4.2 Resource Portfolios

The portfolios of resources analyzed in this study incorporate data from a variety of sources. The database of generation resources included in this study – which reflects the characteristics of existing and future resources – includes inputs from utility IRPs as well as data gathered from ABB Velocity Suite and EIA Form 860. Generally, all operating resources located within the Desert Southwest region and those outside the regional that are owned or contracted by a Southwest utility are included in the portfolio. Figure 4-3 shows the composition of regional existing resource portfolio at three snapshot years: 2021 as today; 2025 as a short-term outlook, and 2033 as a long-term view.

Figure 4-3. Summary of resource portfolios analyzed in this study[31]



4.2.1 Existing Plant Retirements

The portfolios analyzed in this study incorporate future plant retirements based on current utility plans. The specific retirements – which do not vary between the "Existing & Committed Resources" and "IRP Portfolios" scenarios – are summarized in Table 4-2. Today, 5,688 MW of coal-fired generation serve utilities within the region; of this quantity, cumulative coal plant retirements during the study horizon total 1,198 MW by 2025 and 4,702 MW by 2033. Including natural gas plants with planned shutdowns, these retirements will reflect approximately 20% of today's existing firm resource capacity in the Southwest.

In addition to the formally announced retirements listed in Table 4-2, this study assumes that the Harquahala Generating Station, a 1,000 MW merchant natural gas generator located in Arizona that is not currently under long-term contract and is not included in any utility's long-term plan, will not be available to support regional needs by 2025. This assumption reflects the risk that (a) the plant may retire within the study horizon, or (b) its capacity obligations may be sold to another offtaker outside of the region.

[31] A portion of the solar and storage resources added in all scenarios are expected to be paired (or "hybrid") facilities. For clarity of reporting – and because relative sizing of solar and storage at a hybrid facility can vary considerably from one plant to another – this study uses a convention in which the solar and storage capacity are reported separately, as if each was a standalone resource. Within the modeling, a separate interconnection limit limits the combined output of paired resources.

Table 4-2. Planned unit retirements during study horizon

Plant Type	Plant Name & Unit		Location	Summer Capacity (MW)	Retirement Date	Operational Status in 2025	Operational Status in 2033
Coal	Cholla	1	AZ	116	4/30/2025	Retired	Retired
		3	AZ	271	4/30/2025	Retired	Retired
	Coronado	1	AZ	380	12/31/2032	Online	Retired
		2	AZ	382	12/31/2032	Online	Retired
	Craig*	1	CO	124	12/31/2025	Online	Retired
		2	CO	119	12/31/2028	Online	Retired
	Four Corners	4	NM	770	7/6/2031	Online	Retired
		5	NM	770	7/6/2031	Online	Retired
	Hayden*	2	CO	130	12/31/2027	Online	Retired
	San Juan	1	NM	340	6/30/2022	Retired	Retired
		4	NM	507	6/30/2022	Retired	Retired
	Springerville	1	AZ	387	12/31/2027	Online	Retired
		2	AZ	406	12/31/2032	Online	Retired
Coal Subtotal				**4,702**			
Natural Gas	Copper	1	TX	63	12/1/2030	Online	Retired
	H Wilson Sundt	ST3	AZ	104	12/31/2032	Online	Retired
	Newman	1	NM	73	12/1/2022	Retired	Retired
		2	NM	73	12/1/2022	Retired	Retired
		3	NM	90	12/1/2026	Online	Retired
		CC4	NM	227	12/1/2026	Online	Retired
	Reeves	1	NM	44	12/1/2030	Online	Retired
		2	NM	44	12/1/2030	Online	Retired
		3	NM	66	12/1/2030	Online	Retired
	Rio Grande	6	NM	45	12/31/2021	Retired	Retired
		7	NM	46	12/1/2022	Retired	Retired
		8	NM	144	12/1/2033	Online	Online
Natural Gas Subtotal				**1,019**			

* For plants located outside the Southwest, listed capacities reflect Southwest utilities' ownership interests (rather than the full plant capacity)

4.2.2 New Capacity Additions

The new capacity additions included in each portfolio vary across the scenarios. Cumulative nameplate capacity additions are summarized in Table 4-3. The "Existing & Committed" scenarios include only additions of resources already under development at the time of this study – defined as either having a signed PPA or EPC contract (and regulatory approval, if applicable). Resources under development, which total nearly 5,000 MW of new installed capacity, consist primarily of solar (3,281 MW) and storage (1,040 MW), with smaller amounts of wind (455 MW) and one new natural gas unit (Newman CC6, a 226 MW gas-fired power plant). Because all resources under development are expected to be online prior to summer 2025, these assumptions do not vary between the 2025 and 2033 analysis. Additions in the "IRP

Portfolios" scenarios – provided for this study by each utility – reflect an additional 10,000 MW of installed capacity by 2025 and 35,000 MW by 2033 – again, predominantly solar and energy storage.

Table 4-3. Cumulative nameplate capacity additions by scenario relative to 2021

	Existing & Committed Resources		IRP Portfolios	
	2025	2033	2025	2033
Natural Gas*	228	228	1,541	1,726
Geothermal	-	-	-	500
Solar	3,281	3,281	8,186	19,509
Wind	455	455	1,358	3,908
Storage	1,040	1,040	3,459	12,961
DR	5	5	385	889
Total	**5,009**	**5,009**	**14,794**	**39,173**

* Includes microgrid resources

4.3 Load & Renewable Profiles

Of particular importance in LOLP modeling of future electric systems is the ability to capture the inherent variability of load and variable resource profiles across a wide range of weather conditions – while preserving any underlying weather-driven relationships between them. The development of an extensive library of load, wind, and solar profiles that capture possible states of the system across multiple weather years is therefore essential. Figure 4-4 summarizes the data sources used to generate the hourly profiles used in this study.

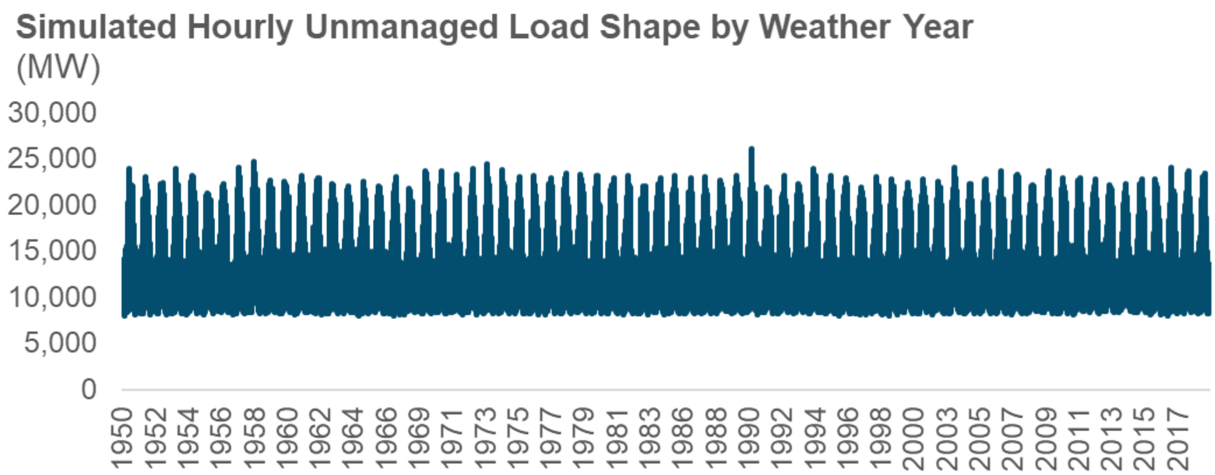
Figure 4-4. Load, renewables, and weather data sources

Profile	Primary Source(s)	Weather Conditions Captured	Notes
Loads	**WECC** Data request **NOAA** Historical Weather Data	2011 2019 1950 2019	• Neural network regression used to backcast hourly load patterns under broad range of weather conditions using recent historical load data (2011-2019) and long-term weather data (1950-2019) • Historical shape scaled to match future forecasts of regional energy demand • Shapes for load modifiers (transportation electrification, new large loads) layered on top of neural network results
Wind	**NREL** WIND Toolkit	2007 2012	• Profiles for **existing wind resources** simulated based on plant locations, known characteristics (e.g. hub height & power curve) • Profiles for **future wind resources** simulated based on generic locations chosen by E3 with input from sponsors
Solar	**NREL** System Advisor Model	1998 2020	• Profiles for **existing utility-scale solar resources** simulated based on plant locations, known characteristics (tracking vs. tilt, inverter loading ratio) • Profiles for **future utility-scale solar resources** simulated based on generic locations and technology characteristics chosen by E3 with input from sponsors • Profiles for **behind-the-meter/distributed solar** simulated for each utility service area

4.3.1 Hourly Demand

To generate hourly load shapes consistent with the statistically adjusted weather record, this study uses neural network regression techniques to extend the short record of historical data. Through this process, this study relies on a library of hourly load profiles that represent how today's electric demands would behave under a wide range of plausible weather conditions consistent with today's climate. This method allows the analysis to capture the variability of load across very long time horizons (i.e., 1-in-2, 1-in-5, 1-in-10 year events, etc.). Additional detail on this simulation process is provided in Technical Appendix A.

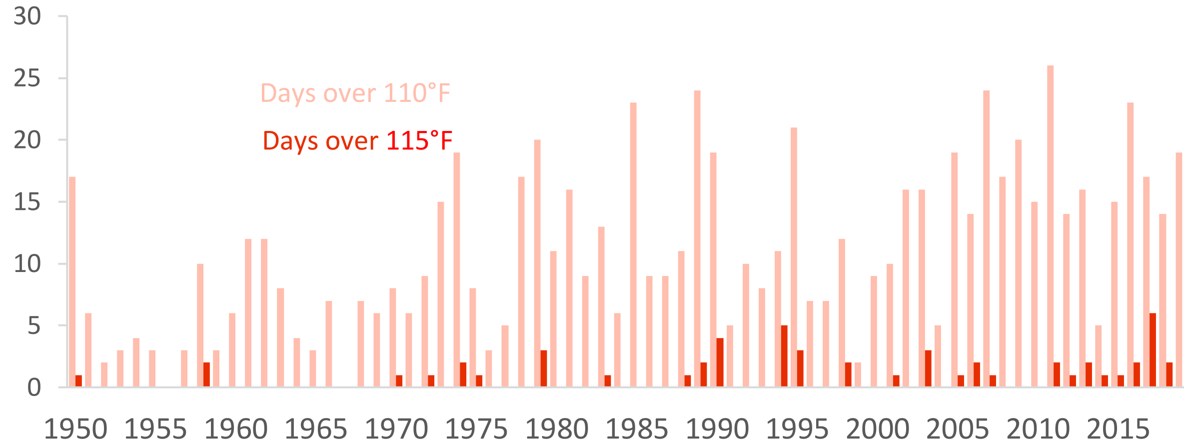
Figure 4-5. Simulated load shape across 70 potential weather years



Climate Adjustment of Historical Data

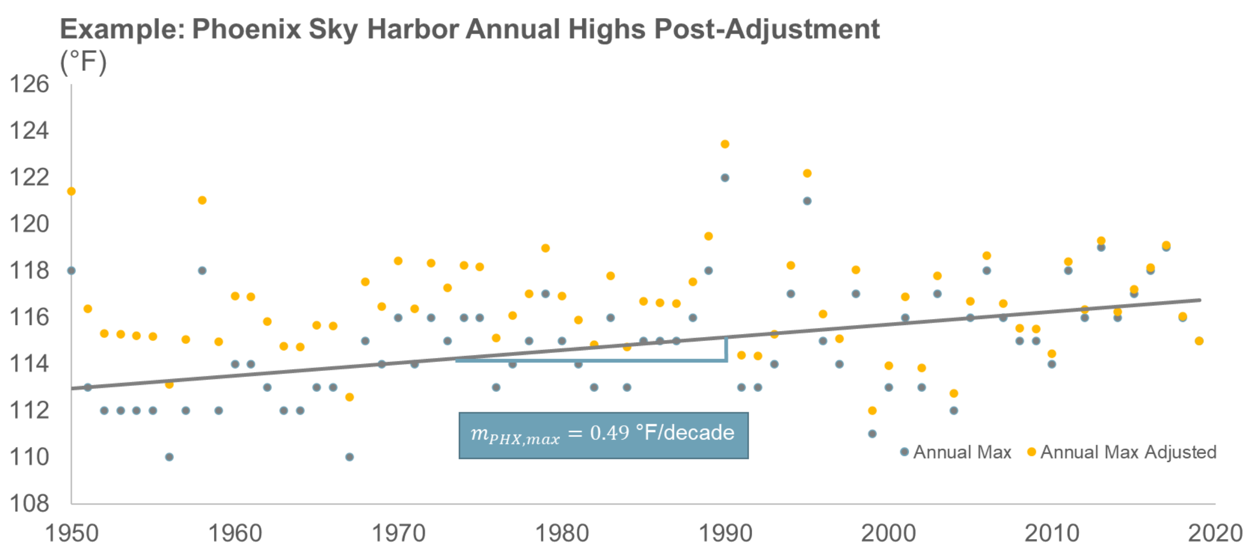
Incorporating a broad range of possible weather conditions is essential to robust probabilistic modeling. In the past, extensive historical weather records have been used directly to represent the distribution of possible future conditions; however, as the impacts of climate change have become more apparent in the historical record, calling this common assumption into question. The presence of a warming trend in historical data is especially clear in the Southwest, where the frequency of extreme high summer temperatures has increased dramatically since the mid-twentieth century (see Figure 4-6). Should observed warming trends continue, traditional analyses which sample only from historically observed weather data risk failing to capture the even-hotter extreme temperatures and resulting reliability events.

Figure 4-6. Increasing Frequency of High Temperature Days at Phoenix Sky Harbor



To account for these warming trends, this study incorporates a linear adjustment to the historical weather record to detrend the warming impacts apparent in the historical data. A statistically adjusted weather record was produced by developing a linear regression on the annual average temperatures observed at each weather station. That regression was then used to create an adjusted temperature for each daily temperature at each weather station, effectively "de-trending" historical temperatures to conditions representative of present-day climate. Figure 4-7 illustrates the effect of this detrending for the Phoenix Sky Harbor weather station.

Figure 4-7. Adjusted Weather Record Methodology Example

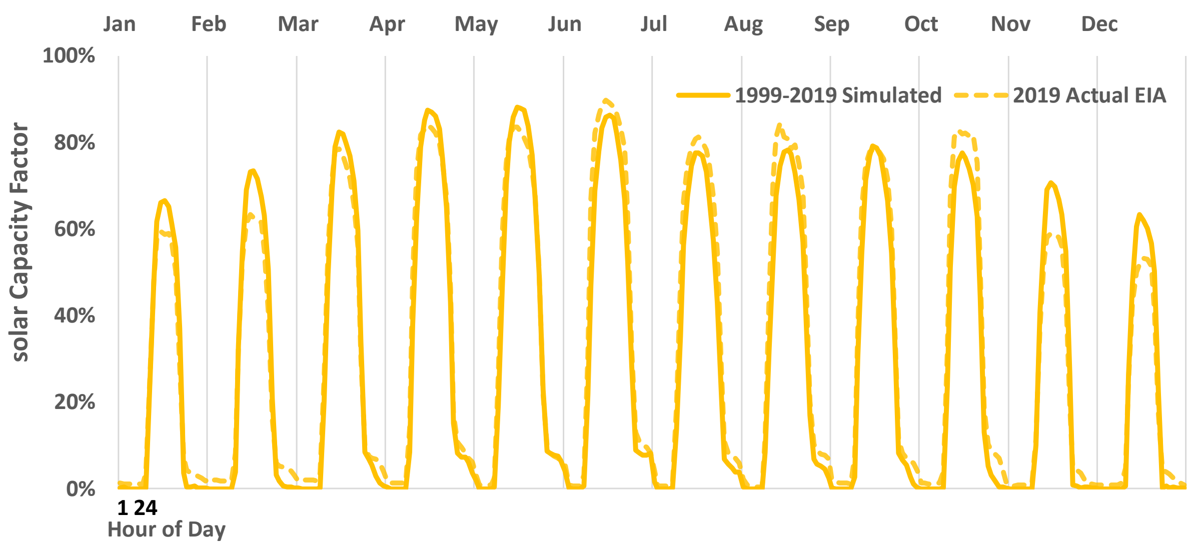


4.3.2 Hourly Solar Generation

Hourly profiles for utility-scale and behind-the-meter solar resources are simulated using NREL's System Advisor Model (SAM) for the historical period 1998-2019. Utility-scale profiles are simulated based on plant-specific characteristics (location, tracking type, tilt, azimuth and inverter loading ratio) as reported in EIA Form 860 for existing plants; future resources are simulated assuming a generic representative single-axis tracking plant with an inverter loading ratio of 1.3 based on industry trends as captured in Lawrence Berkeley National Laboratory's (LBNL) *Utility-Scale Solar* report. Behind-the-meter solar profiles are simulated for major load centers in the Southwest region based on generic assumptions for residential and non-residential installations reflected in LBNL's *Tracking the Sun*.

Simulated profiles from existing solar plants were benchmarked against aggregate BA-level historical hourly production data gathered from EIA for the period 2019-2020. The simulated profiles capture the diurnal and seasonal production patterns well; average daily and seasonal patterns for simulated and historical data sets are illustrated in Figure 4-8. Generally, simulated solar shape shows similar behavior and capacity factor in most months of a year. Average production profiles and levels track particularly well in the summer months (June through September) when electric demand is highest.

Figure 4-8. Benchmarking month-hour average solar capacity factor (%)[32]



4.3.3 Hourly Wind Generation

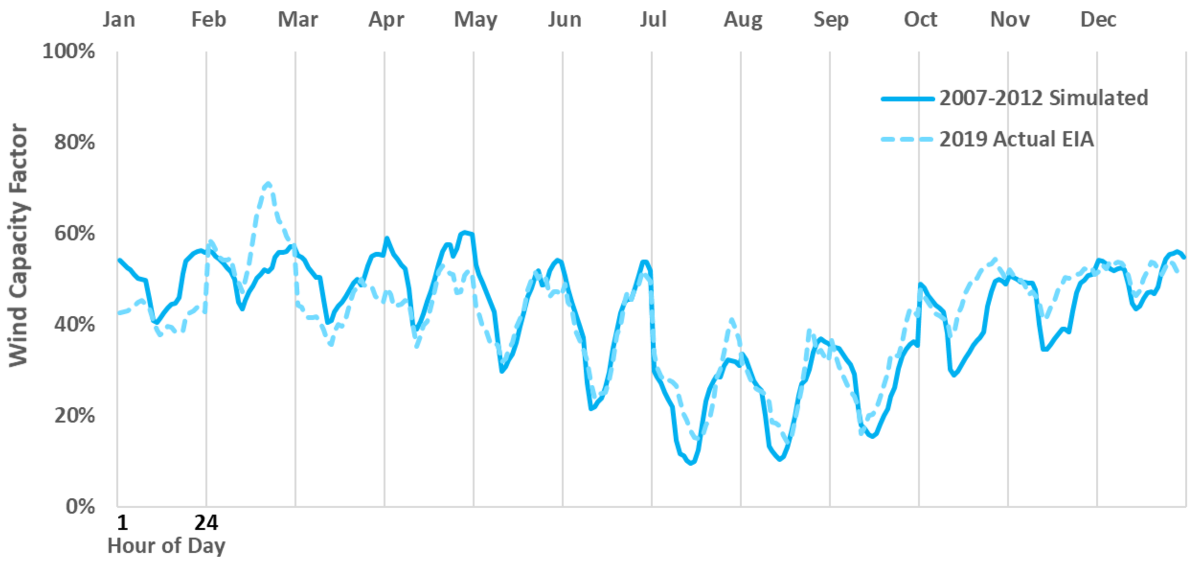
Hourly profiles for existing & committed wind plants are simulated from meteorological and turbine power data gathered from NREL's WIND Toolkit for the historical period 2007-2012. Each plant's profile depends upon plant-specific design characteristics, including the hub height and power curve for the turbines installed.

These profiles are then benchmarked against actual hourly production data from wind resources in the region in 2019. Because the WIND Toolkit does not produce simulations for a historical period during which actual historical data for wind production is readily available, benchmarking of wind profiles focuses on seasonal and diurnal patterns through a comparison of month-hour capacity factors in the simulations

32 The low level of production that persists into the evening is a result of APS' Solana concentrating solar power (CSP) plant. This pattern is unique to this plant and is not reflected in any of the solar PV simulations (for existing or future resources).

(2007-2012 weather) and in historical data (2019) available from EIA. The benchmark results are illustrated in Figure 4-9. Generally, hourly wind output is higher during winter months and lower during summer months. However, while overall capacity factors tend to be lower in the summer months, the times of day when wind capacity factors are the highest – typically later in the day and evening – complement the diurnal production patterns of solar resources well.,

Figure 4-9. Month-hour average wind capacity factor (%)



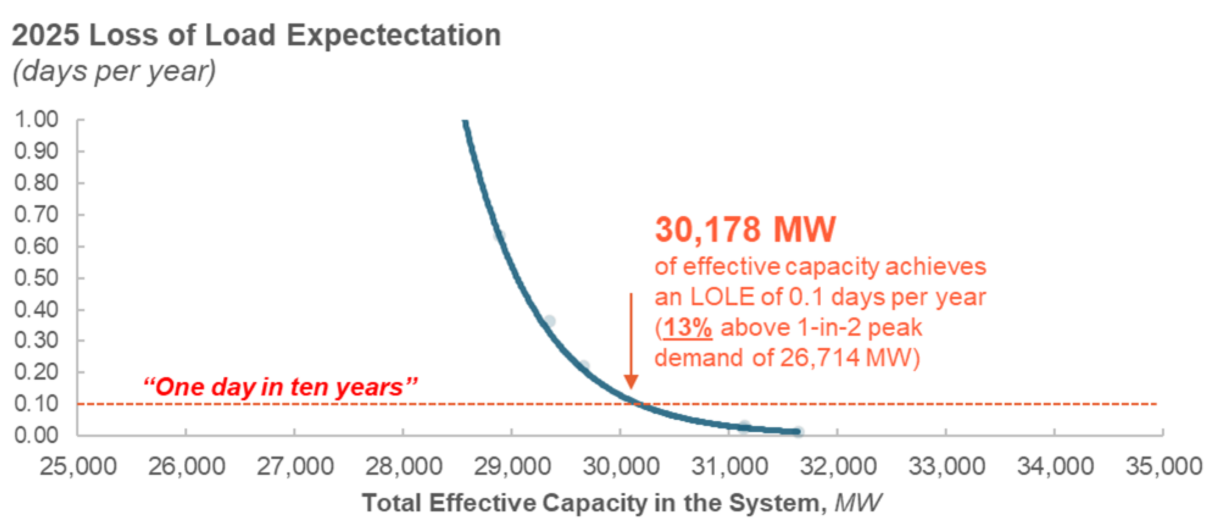
5 Results

5.1 Regional Capacity Need

Determining the Southwest region's effective capacity need and ensuring the regional electric system's reliability depend on two main factors: the patterns of electricity demand across all hours and the need to maintain a minimum level of operating reserves. Electricity demand in the Southwest is highest during the intensely hot summers. The total effective capacity requirement must cover those load peaks and troughs and the additional operating reserve throughout the year.

Loss of load probability modeling provides a method of establishing a requirement for effective capacity that is directly tied to a specific statistical standard for adequacy. The relationship between these two quantities – illustrated in Figure 5-1 for a 2025 system – is such that increasing levels of effective capacity yield an increasingly reliable system. To meet a reliability standard of LOLE of 0.1 days per year in 2025 – when the expected regional coincident peak demand is forecasted to reach 26,700 MW – the Southwest needs 30,178 MW of effective capacity to cover the region's load and operating reserves. Expressed in percentage terms relative to peak demand, this is equivalent to 13% planning reserve margin above the 1-in-2 peak.

Figure 5-1. Relationship between loss of load expectation (LOLE) and the total need for effective capacity



By 2033, continued increases in load will continue to drive the absolute need for effective capacity higher. By 2033, the region's 1-in-2 peak grows to 31,800 MW; meeting regional needs according to a 0.1 LOLE reliability standard in 2033 requires 35,800 MW of effective capacity. While the absolute quantity of capacity needed grows, the relative requirement remains relatively stable: this quantity of capacity is 13% higher than the regional 1-in-2 peak demand. The stability of this planning reserve margin throughout the horizon holds true because the amount of effective capacity needed is independent of the resources in the portfolio: "need" is calculated in a manner that only reflects the nature of electricity demand and operating reserves across all hours of the year.

The 13% requirement for effective capacity identified in this study differs from the specific planning reserve margin requirements currently used by utilities in the region; however, this result does not directly conflict with individual utilities' PRM requirements. There are several key differences between the analysis presented here and utilities' own analysis to inform their respective requirements:

+ Most importantly, the PRM requirement is intrinsically tied to the conventions used to count capacity towards the requirement. In this analysis, regional capacity needs in terms of *effective* capacity, in which all resources – firm and non-firm – must be derated based on their respective limitations, using a "perfect capacity" resource as a benchmark. While conventions throughout the region vary, a number of the region's utilities continue to rely on a more traditional accounting scheme, in which resources are counted towards the requirement without deration for the possibility of outages. Under this accounting scheme, higher requirements would be expected, as the requirement itself must build in some margin for the risk of unit outages.
+ Additionally, while this analysis presents a view of the level of reliability that might be achieved across the region, each utility remains responsible for planning a portfolio of resources to meet the reliability needs of its own customers' loads. In the absence of a formalized protocol for sharing of capacity resources among entities within the Southwest, utilities plan for the resource adequacy of their own systems in a way that may not harvest the full physical load and resource diversity of the region.
+ Finally, this analysis assumes that all resources are available to serve all loads in the region at all times (except when unavailable due to unplanned outages) with no transmission constraints or transactional friction. In reality, each utility operates its own BAA, market transactions are subject to significant friction and transaction costs, and transmission constraints sometimes prevent power from flowing from one BAA to another.

The Exponential Relationship Between LOLE and Effective Capacity

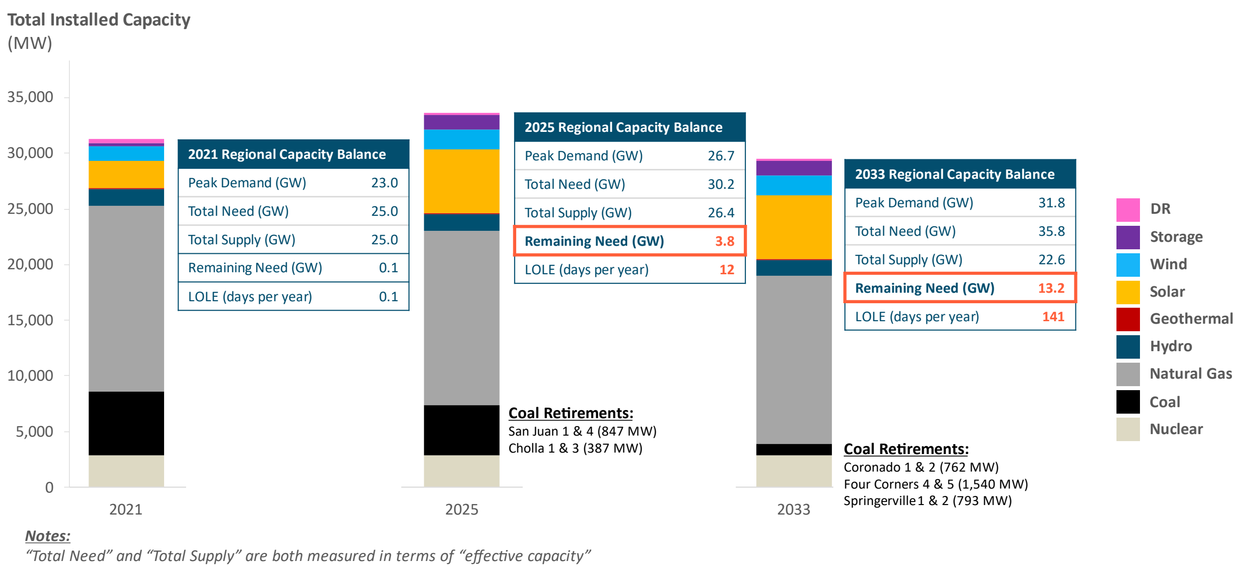
One of the most striking and important aspects of the relationship highlighted in Figure 5-1 is its nonlinearity: each unit of effective capacity removed from a system in balance results in degradation of reliability by an increasing amount. For instance: removing 500 MW of effective capacity from a system that meets an LOLE standard of 0.1 days per year approximately double the frequency of loss of load events to 0.2 days per year; however, the loss of an additional 500 MW of effective capacity from this same system would approximately double frequency once more to 0.4 days per year. These effects are characteristic of a relationship that is exponential in nature. Understanding this relationship is particularly important in an era in which so many new uncertainties could impact the real-world reliability of the system, as the consequences of unanticipated shortfalls could have outsized impacts on the level of reliability achieved.

5.2 Existing & Committed Resources

A portion of the total capacity needs identified above will be met by resources that exist today or that have already been procured by utilities.[33] Figure 5-2 summarizes the evolution of the load-resource balance in the region considering only resources that exist today or that are in development. These results highlight a steadily increasing need for additional effective capacity throughout time:

+ As of 2021, the level of reliability provided by the portfolio of existing resources was roughly in line with a traditional "one-day-in-ten-years" standard.
+ By 2025, due primarily to load growth and resource retirements, an effective capacity gap of 3.8 GW. Without any additional resources, this portfolio would be insufficient to meet demand in the region on roughly twelve days each year.
+ By 2033, continuation of these trends expands the effective capacity gap to over 13 GW; the remaining existing resources would be insufficient to meet regional loads on almost half the days of the year.

Figure 5-2. Summary of regional loads and resources, Existing & Committed scenarios



5.2.1 Regional Load-Resource Balance

The 2025 load-resource balance is further decomposed by resource type in Table 5-1. This table, repeated for subsequent scenarios, includes three metrics for each technology:

+ **Installed capacity (MW)**, which is based on the maximum summer nameplate plant rating;

[33] For the purposes of this study, a resource is treated as "committed" if it has a signed PPA with a utility (and regulatory approval, where necessary). The classification of what counts as "committed" for the purposes of this study was determined in fall 2021; utilities' ongoing procurement efforts since this time may have increased the amount of capacity that would qualify as "committed" today.

- **Effective capacity (MW)**, which reflects its total contribution to resource adequacy as measuring using an ELCC methodology;[34] and
- **Effective capacity (% of Rated)**, which expresses the average contribution, per unit of nameplate capacity, of the resources in the portfolio.

By 2025, the combination of remaining existing resources and new resources in development will, in aggregate, contribute 26,388 MW towards the region's total capacity need of 30,178 MW, falling 3,789 MW short of total need for effective capacity. Contributing to the 2025 existing and contracted portfolio's capacity value, nuclear, coal, natural gas, and other thermal resources provide 82%, Hydro, wind, and solar provide 13%, and batteries, pumped hydro, and demand response provide 5% of the portfolio's total capacity value. Compared to the benchmark 0.1 days per year of LOLE, the Southwest's capacity shortfall position will result in 12 days per year of LOLE, far higher than the target level of reliability.

Table 5-1. 2025 load and resource table, Existing & Committed resources only

Loads & Resource	Installed Capacity (MW)[1]	Effective Capacity (MW)[2]	ELCC (% of Installed)
Nuclear	2,858	2,783	97%
Coal	4,490	4,026	90%
Natural Gas	15,659	14,711	94%
Other	84	83	98%
Hydro	1,437	1,137	79%
Geothermal	77	72	93%
Solar	5,778	1,531	27%
Wind	1,781	696	39%
Storage	1,299	1,167	90%
Demand Response	238	184	77%
Total Resources	33,701	26,388	
Median ("1-in-2") Peak Demand		26,741	
Total Effective Capacity Need (+13% PRM)		**30,178**	
Capacity Surplus (Shortfall)		**(3,789)**	
Achieved Reserve Margin		-1%	

[1] "Installed capacity" refers to the resource's maximum summer rated capacity
[2] "Effective capacity" is a measurement of the resource's contribution to resource adequacy needs

The 2033 load-resource balance is shown in Table 5-2. By 2033, additional retirements and continued load growth will increase the remaining capacity need to 13,277 MW of effective capacity. Without additional

[34] Because of the presence of interactive effects between variable and energy-limited resources, attributing capacity value to individual resources and/or technologies within a portfolio requires an allocation of the total effective capacity value of the aggregate portfolio. This study relies on the "Delta Method" for ELCC allocation, which attributes value to individual technologies based on their respective marginal ELCCs relative to a system with no other non-firm resources ("First-In Marginal ELCC") and a portfolio with all other non-firm resources ("Last-In ELCC"). This method, recently adopted by PJM for capacity accreditation in its market, is summarized in greater depth in the E3 whitepaper "Capacity Planning in the Decarbonization Era."

resources, the region's risk of experiencing reliability events would far exceed the traditional LOLE benchmark of 0.1 days per year.

Table 5-2. 2033 load and resource table, Existing & Committed resources only

Loads & Resource	Installed Capacity (MW)[1]	Effective Capacity (MW)[2]	ELCC (% of Installed)
Nuclear	2,858	2,783	97%
Coal	1,022	966	95%
Natural Gas	15,029	14,281	95%
Other	84	83	98%
Hydro	1,437	1,101	77%
Geothermal	77	72	93%
Solar	5,758	1,416	25%
Wind	1,781	594	33%
Storage	1,299	1,174	90%
Demand Response	163	128	79%
Total Resources	29,508	22,597	
Median ("1-in-2") Peak Demand		31,787	
Total Effective Capacity Need (+13% PRM)		35,824	
Capacity Surplus (Shortfall)		**(13,227)**	
Achieved Reserve Margin		-29%	

[1] "Installed capacity" refers to the resource's maximum summer rated capacity
[2] "Effective capacity" is a measurement of the resource's contribution to resource adequacy needs

5.2.2 *Statistical Reliability Metrics*

Direct statistical metrics produced by RECAP provide a useful complementary perspective to the load-resource balance accounting discussed above. Table 5-3 summarizes a number of these outputs for the Existing & Committed resource scenarios. Without addition of new capacity to the utilities' portfolios, these metrics highlight the potential for rapid degradation of reliability in the region: by 2025, the region's resources would be insufficient to meet load roughly 12 days each summer for an average of three hours per day; by 2033, the region would experience supply shortfalls 140 days per year (i.e. throughout the entire summer) for an average of ten hours per day if no new resources were added.

Table 5-3. Reliability metrics for 2025 and 2033 systems

Metric	2021 Existing	2025 Existing & Committed	2033 Existing & Committed
Loss of Load Expectation *(days per year)*	0.15	12	140
Average Event Duration *(hours per event)*	3.0	3.0	10.1
Normalized Expected Unserved Energy	2.7	266	34,272

(parts per million)			
Effective Capacity Surplus (Shortfall) *(MW)*	**(225)**	**(3,789)**	**(13,227)**

Understanding when the greatest risk to resource adequacy occurs lays the foundation on calculating new resources' ability to contribute to resource adequacy. The types and quantities needed to ensure regional reliability depend not only on the size of the resource need identified above, but on the characteristics of existing loads and resources – and, by implication, the timing of remaining need. As renewable penetration grows in the Southwest, the challenge for utilities will be the net load, rather than the gross load. For summer peaking systems aiming to integrate large quantities of solar, planners will need to contend with emerging dynamic of an evening net peak: even as solar resources are capable of producing large amount of generation during the period of higher demand, their presence will shift the "net peak" period into the evening. This dynamic – accounting for the variable resources in the "Existing and Committed" scenario – is illustrated in Figure 5-3. Increased renewable penetration in the Southwest's 2025 system sharpens and pushes the daily peaks out later to the evening.

Figure 5-3. Increased renewable penetration in the Southwest's 2025 system sharpens and pushes the daily peaks out later to the evening

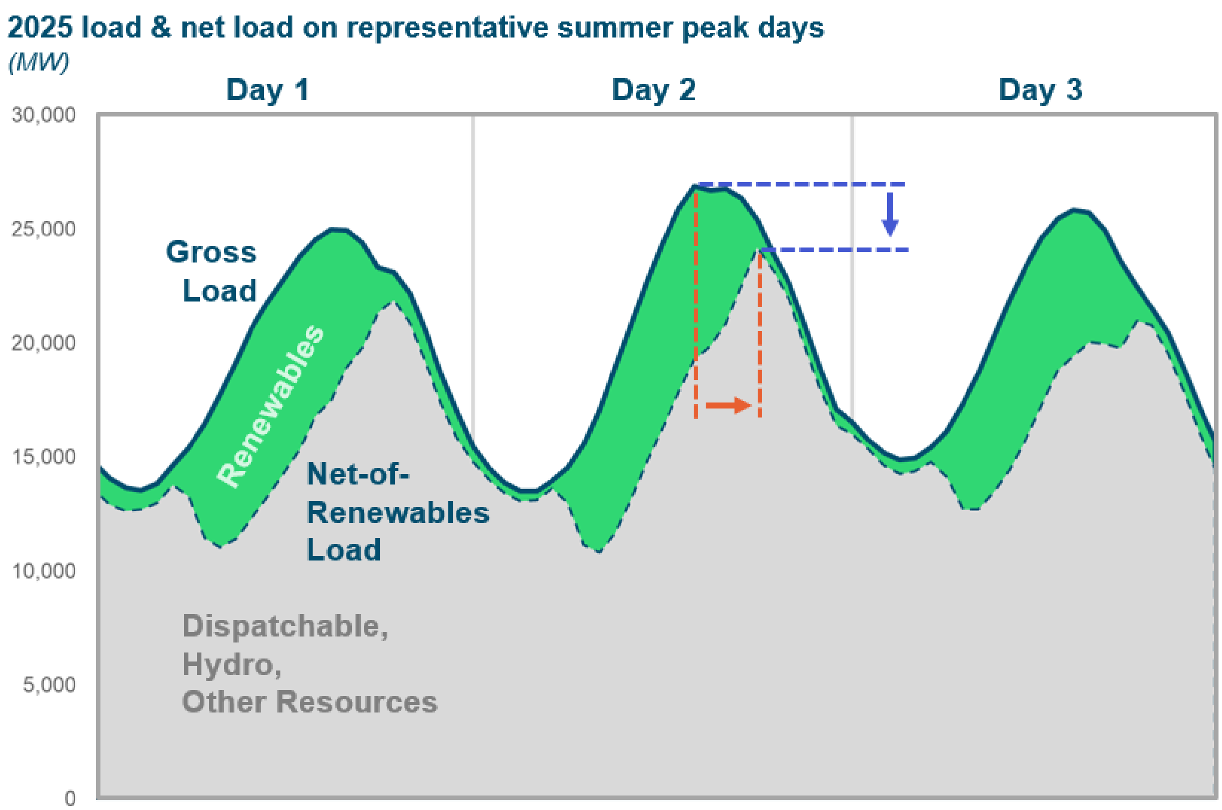
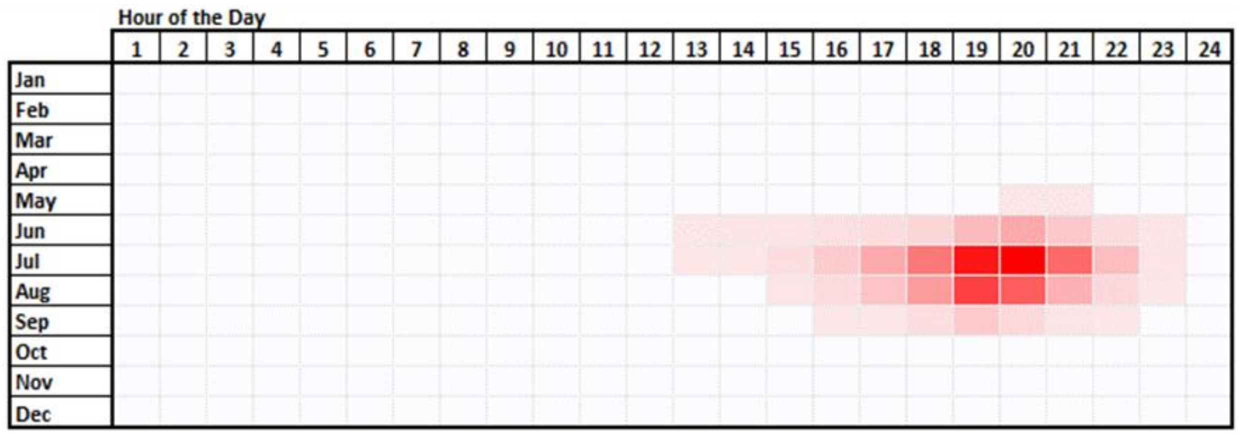


Figure 5-4, which summarizes the relative risk of experiencing a generation shortage (or "loss of load probability") by month and time of day, offers a more generalized view of this same phenomenon. The periods in which risk – and by extension, need for new resource capability – is greatest will shift into the summer evenings, with the highest loss of load probability occur at 7-8pm in July and August. Due to the "shape" of this need, resources that are capable of generating on demand consistently during evening hours will tend to achieve higher capacity value in this future Southwest system.

Figure 5-4. Relative periods of resource insufficiency by month and time of day, Existing and Committed resources in 2025[35]



5.3 Meeting the Region's Remaining Needs

With few opportunities to contract for additional existing resources within the region remaining, meeting future resource needs will require addition of new generation at significant scale. This study identifies effective capacity gaps of roughly 4,000 MW and 13,000 MW by 2025 and 2033, respectively – but the amount of new *installed* capacity that will be needed to cure these deficiencies will be larger still due to the physical and operational constraints that impact each resource's ability to contribute effective capacity.

To illustrate how various resources (and combinations of resources) can contribute to meeting these remaining needs, this study presents two analyses:

1. A marginal ELCC analysis, which examines how much effective capacity is provided by incremental additions of specific types of resources; and
2. A portfolio analysis of the utilities' IRP resources, which assesses the extent to which that portfolio of resources will result in a reliable mix of resources for the region.

5.3.1 ELCC Analysis of Additional Resources

As described above, the Southwest will face a near-term capacity shortfall and new resources should be procured to meet growing loads reliably. For utilities choosing resources to fill the capacity shortfall, planners should choose resources that effectively contribute to system need, more specifically, the timing

[35] Note that because this system is far below typical standards for resource adequacy, the periods of non-zero loss of load probability are spread across a broader number of hours and months than in a system that is in balance.

of the capacity need. To measure a resource's effectiveness, this study uses effective load carrying capability (ELCC) to explore the capabilities of different resources to fill this remaining need.

As discussed in Section 2.3.3, ELCC is a technology-agnostic metric that captures how well a resource can provide capacity when the system needs it most, capturing both its coincidence with load and also how it interacts with other resources in the portfolio. This section presents the role of renewables and energy storage resources can play to contribute to the Southwest's capacity position.

Analysis of the ELCC of individual resources (or portfolios of resources) provides useful insights into how the remaining resource needs may be met. The following charts show how renewables and storage provide capacity to the Southwest system in two different ways:

(1) **Total Portfolio ELCC,** the total amount of capacity value provided by a portfolio of solar, wind, storage, and demand response resources and changes as a function of their respective penetrations; and
(2) **Marginal ELCC,** the amount of additional effective capacity provided by an incremental unit of installed capacity of a specific resource.

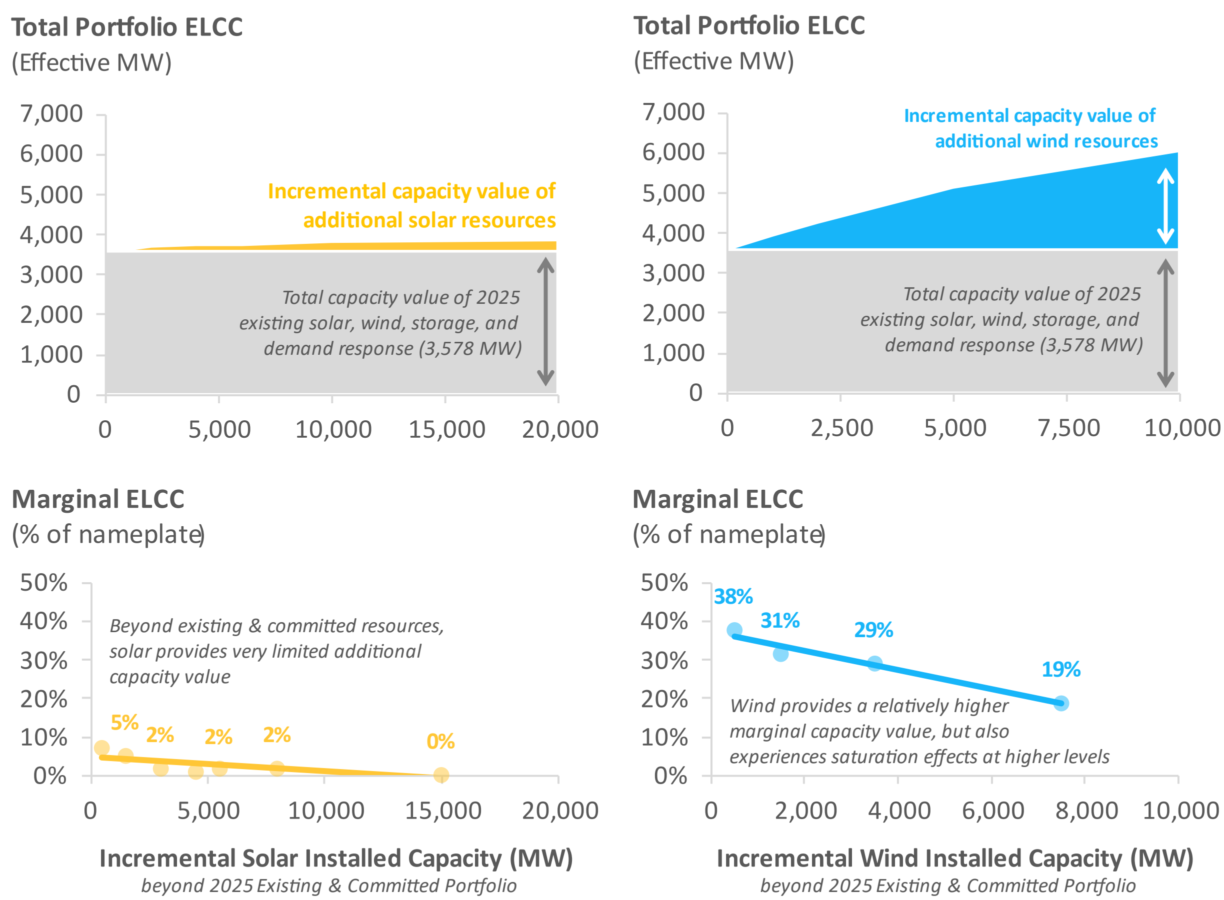
Both charts use the same data but tell the story in two different ways. The capacity value chart shows how much total effective capacity the entire resource group provides, useful for utilities procuring new resources to fill their need. The Incremental ELCC chart shows additional capacity value utilities can get from each addition of a resource, useful to understand how value changes as a function of penetration.

5.3.1.1 Variable Resources

While both wind and solar provide more capacity upfront, the incremental ELCC curves for solar and wind resources highlight the limited value that variable renewable resources alone can contribute to meeting the region's remaining resource needs. Solar's capacity value diminishes due to the misalignment relative to the highest load hours across the year—hot summer late evenings and when the sun is set—and thus, saturating solar resources' capacity value. While wind's capacity value does not saturate as quickly, increasingly levels of the same wind resource will inevitably diminishes its capacity value.

These dynamics are illustrated in Figure 5-5, which shows how much capacity value results from the addition of incremental wind and solar resources beyond those already included in the Existing & Committed scenarios. The marginal capacity value of additional solar beyond this level is below 10% and, with increasing levels, declines towards zero as the net peak shifts entirely to hours after sundown. The marginal capacity value of additional wind is higher due to its more favorable production patterns during summer evenings, but it, too, will exhibit saturation effects at increasing penetrations.

Figure 5-5. Solar and wind capacity value and incremental ELCC in 2025



5.3.1.2 Energy-Limited Resources

Energy-limited resources, which include hydroelectric generation, demand response, and storage, can often be dispatched flexibly by system operators but are typically limited in the length or duration of their output. These restrictions may be a result of hydrological conditions (hydro), limits on state of charge (battery storage), or program limitations on the number and duration of program calls (demand response). These limitations have direct implications for the value these resources can contribute to resource adequacy.

Figure 5-6. Potential contribution of additional storage resources to regional resource adequacy needs

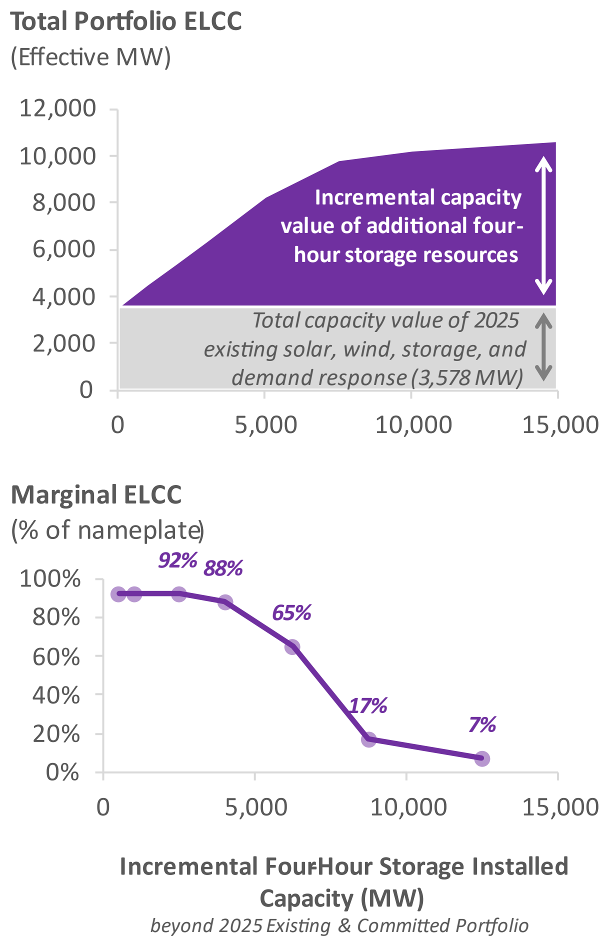


Figure 5-6 shows the incremental ELCCs that result from the addition of four-hour storage to the 2025 Existing & Committed resource portfolio. The characteristics of four-hour storage make it well-suited to dispatch during the net peak period when load is highest; as a result, at low penetrations, the capacity value of additional storage resources is relatively high. As the total additions of storage increase, however, saturation effects become evident, and the capacity value of storage declines steeply beginning at approximately 5,000 MW of installed capacity. The amount of additional capacity value that storage alone can provide eventually levels out as the marginal capacity value drops below 10%. The saturation effect and the reduction in value can be attributed to several causes:

+ At low penetrations, storage resources are only needed to dispatch for a small number of hours each day. As the penetration of storage resources increases, the time horizon across which they must dispatch increases. The increasing need for duration results in a reduction in its capacity value (e.g. a four-hour battery can only dispatch at 50% of rated capacity if needed for eight hours).
+ At low penetrations, energy storage resources have sufficient opportunities to charge from surplus energy available to the system (either excess solar during the day or excess thermal at night). As their penetration increases, so does the amount of energy needed to recharge the fleet between cycles. As a result, portfolios heavily reliant on energy storage may face challenges under multi-day high load events, when their opportunities to recharge fully before being needed again may be limited.

The contribution of demand response to resource adequacy – an "energy-limited" resource by virtue of the inherent limits on frequency and length of calls included in program design – is, in many respects similar to energy storage. Its capacity value depends significantly on its "duration," and it will also exhibit saturation effects for the same reasons as energy storage. Figure 5-7 illustrates this effect for incremental tranches of a generic four-hour demand response resource, whose capacity value declines as successive increments are added to the system.

The capacity value of additional demand response resources may vary as a function of limits on the frequency and length of calls; this effect is illustrated in Table 5-4 for demand response programs with varying characteristics. Not surprisingly, the capacity value of additional demand response resources increases with (a) increasing frequency of calls, and (b) increasing duration of calls.

While this study did not examine the nature of interactive effects between battery storage and demand response, it is important to note that because of their similar abilities and constraints in contributing to resource adequacy needs, these two resources typically exhibit negative interactive effects. Much like the marginal capacity value of battery storage decreases as its penetration increases, the marginal capacity value of *demand response* will also decrease as the penetration of *battery storage* increases. Similarly, the marginal capacity value of *battery storage* will also decrease as the penetration of *demand response* increases. Accounting for these interdependencies accurately is crucial to ensuring that the total capacity value from a portfolio of storage and demand response resources is not overstated.

Figure 5-7. Potential contribution of additional demand response resources to regional resource adequacy needs

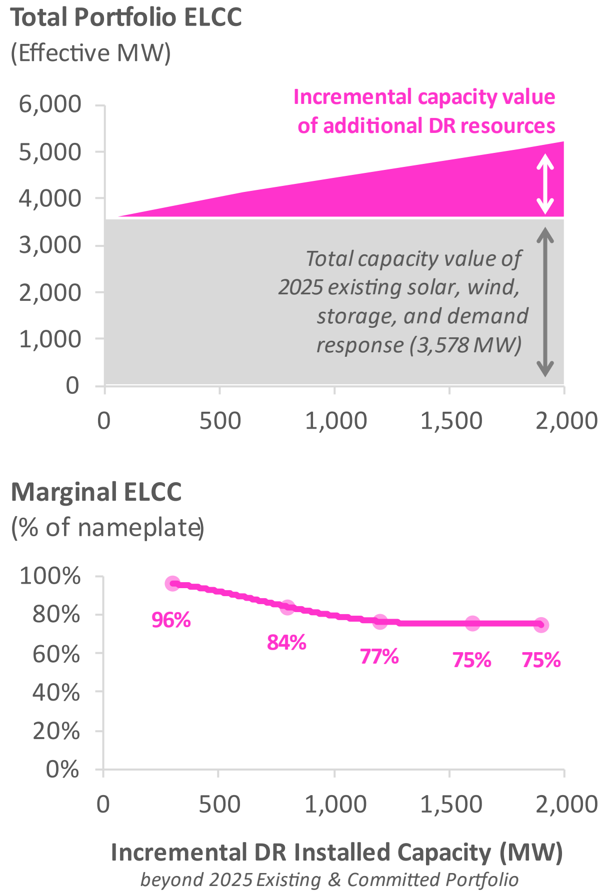


Table 5-4. Capacity value of additional demand response programs as a function of limits on frequency and duration (relative to 2025 Existing & Committed portfolio)

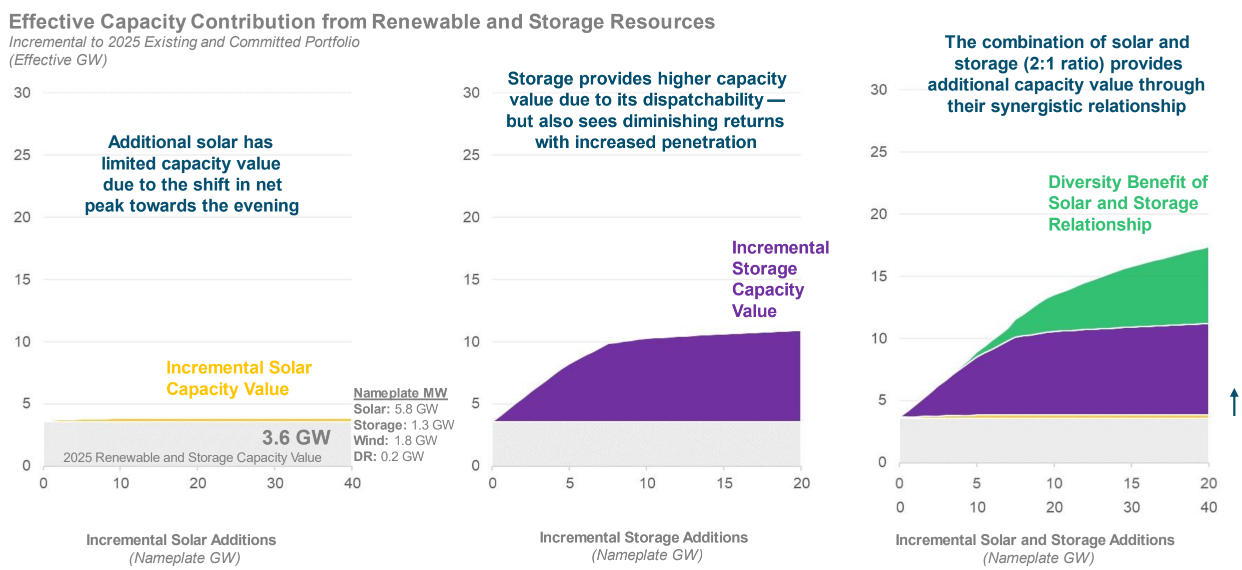
		Max Number of Calls per Year			
		1	2	5	10
Max Duration of Call (hrs)	2	45%	58%	72%	72%
	4	50%	63%	83%	85%
	8	50%	64%	84%	86%

5.3.1.3 *Combinations of Resources*

While each individual resource highlighted above exhibit saturation effects at some scale, combinations of resources also exhibit interactive effects. In some cases, this can lead to outcomes where the total capacity value provided by a portfolio is greater than the sum of its individual parts. This is characteristically true of solar and storage resources, which form a natural complementary pair: as solar shifts load away from the peak, it also reduces the duration of the “net peak” period, allowing storage resources to contribute more effectively to resource adequacy.

To illustrate the importance of this effect, the combined ELCC for a portfolio of solar and four-hour storage resources is compared against the value of those two resources independently. For the purposes of this example, additional solar and storage resources are added to the 2025 portfolio at a two-to-one ratio; that is, 2,000 MW of solar are added for every 1,000 MW of storage added. The results of this exercise are shown in Figure 5-8.

Figure 5-8. Illustration of the diversity benefit captured by ELCC that results from the presence of solar and storage on the same system



In this example, the presence of a “diversity benefit” is clear:

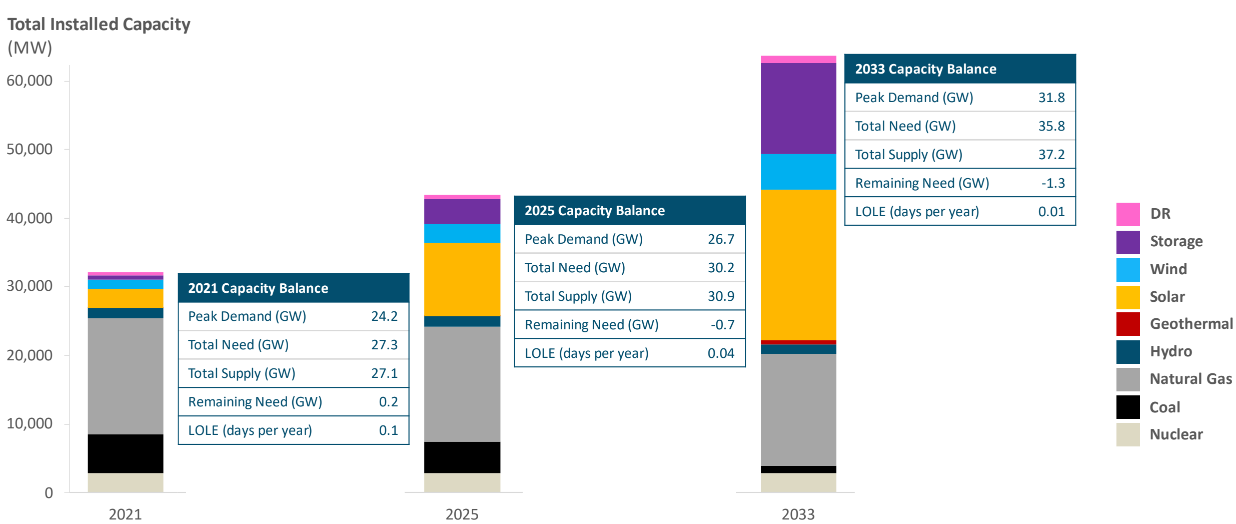
- **Adding solar alone** to the portfolio provides very little additional capacity value; this is due to the fact that by 2025 the net peak period has already shifted into the evening.
- **Adding storage alone** initially provides significant value to the portfolio, but beyond 5,000 MW of incremental capacity its value drops off sharply (reflected in the flattening trend of the incremental storage capacity value).
- **Adding solar and storage together** can mitigate some of the decline in ELCC that results from individual resource saturation; the green wedge in the chart reflects the incremental diversity benefit that results from the two resources together in combination.

While this effect can be significant, even a combination or portfolio of variable and energy-limited resources will eventually exhibit saturation effects and declining marginal value (note that the curve in the far right also eventually flattens out).

5.3.2 IRP Portfolio Analysis

In assessing options for meeting regional capacity needs, this study also examines the degree to which the Southwest utilities' execution of the plans laid out by their IRP portfolios would position the region to maintain reliability. These plans, in aggregate, envision development of substantial quantities of new resources in the coming decade: a total of nearly 15,000 MW of new installed capacity by 2025 and nearly 40,000 MW by 2033. While most of the additional capacity reflected in these plans is solar and energy storage, these additions also include smaller quantities of wind, demand response, geothermal, and natural gas. Figure 5-9 summarizes the impact these portfolios would have upon regional reliability; under Base Case assumptions, these new resources are sufficient to meet the region's residual reliability needs. In 2025, when the total need for effective capacity is 30,200 MW, the aggregate IRP portfolios provide 30,900 MW of effective capacity, limiting the frequency of loss of load to 0.04 days per year.

Figure 5-9. Summary of regional load-resource balance, IRP Portfolio scenarios



Notes:
"Total Need" and "Total Supply" are both measured in terms of "effective capacity"

5.3.2.1 Regional Load-Resource Balance

Table 5-5 and Table 5-6 summarizes the load-resource balance under the IRP scenario in 2025 and 2033, respectively. Both portfolios have sufficient effective capacity to meet the 13% reserve margin requirement (or the 0.1 LOLE standard), largely due to the significant scale of solar and storage additions. Wind, demand response, and natural gas additions also play important roles in allowing these portfolios to meet the target reliability standard

Table 5-5. 2025 load and resource table with IRP portfolio resources

Loads & Resource	Installed Capacity (MW)[1]	Effective Capacity (MW)[2]	ELCC (% of Installed)
Nuclear	2,858	2,783	97%
Coal	4,490	4,026	90%
Natural Gas	16,972	16,064	95%
Other	84	83	98%
Hydro	1,437	1,124	78%
Geothermal	77	72	93%
Solar	10,683	2,327	22%
Wind	2,684	996	37%
Storage	3,718	2,996	81%
Demand Response	618	468	76%
Total Resources	**43,621**	**30,938**	
Median ("1-in-2") Peak Demand		26,741	
Total Effective Capacity Need (+13% PRM)		**30,178**	
Capacity Surplus (Shortfall)		**760**	
Achieved Reserve Margin		16%	

[1] "Installed capacity" refers to the resource's maximum summer rated capacity
[2] "Effective capacity" is a measurement of the resource's contribution to resource adequacy needs

Table 5-6. 2033 load and resource table with IRP portfolio resources

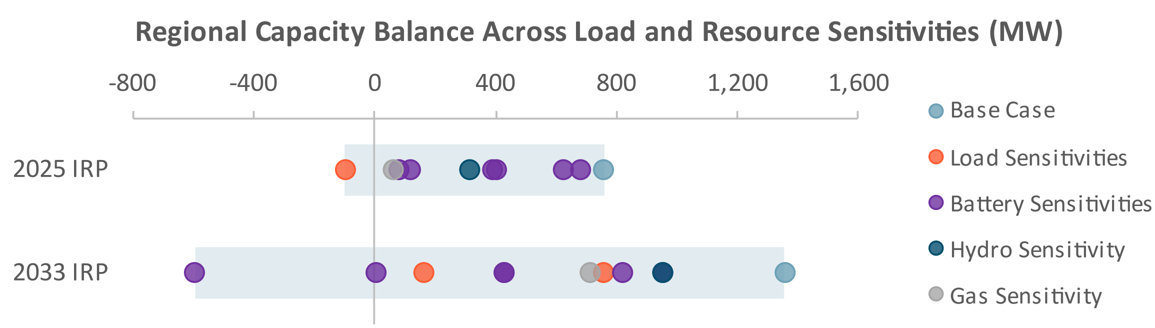
Loads & Resource	Installed Capacity (MW)[1]	Effective Capacity (MW)[2]	ELCC (% of Installed)
Nuclear	2,858	2,783	97%
Coal	1,022	966	95%
Natural Gas	16,527	15,920	96%
Other	84	83	98%
Hydro	577	537	93%
Geothermal	1,437	1,050	73%
Solar	21,986	5,601	25%
Wind	5,234	1,693	32%
Storage	13,220	8,082	61%
Demand Response	1,047	465	44%
Total Resources	**63,492**	**37,180**	
Median ("1-in-2") Peak Demand		31,787	
Total Effective Capacity Need (+13% PRM)		**35,824**	
Capacity Surplus (Shortfall)		**1,356**	
Achieved Reserve Margin		17%	

[1] "Installed capacity" refers to the resource's maximum summer rated capacity
[2] "Effective capacity" is a measurement of the resource's contribution to resource adequacy needs

While solar and storage will provide most of the region's new capacity between now and 2033, incremental additions of solar and storage after 2033 will see less capacity value. This diminished value already starts in 2025 and continues to see larger declines in 2033. At today's level of storage penetration, the entire resource group receives between 90-100% of capacity value, but at nearly ten times this penetration by 2033, Table 5-6 shows that the total class of storage's capacity value is only 62% of its total nameplate. This diminishing effect can be seen in [Figure storage ELCC and Figure Solar + Storage ELCC]. By 15 GW of total storage resource, the contribution of additional storage start to diminish rapidly. This reduction in incremental capacity value can be attributed to the timing of loss of load risk as more solar and storage connect to the grid in the Southwest.

While these margins are indicative of a small capacity surplus within the region under Base Case assumptions, the breadth of uncertainties regarding future conditions prevents a conclusion that these portfolios might be overly reliable. Uncertainties regarding the future impacts of climate change on extreme load, the performance of newly commercialized battery storage technologies, performance of natural gas generators during increasingly extreme weather conditions, and the risk of extreme drought and its corresponding impact on hydro capability could all have material impacts on the resource balance. This study investigates each of these risks through sensitivity analysis (discussed in detail in Section 6.1 through 6.4); Figure 5-10 summarizes the range of different reliability outcomes across the sensitivities on these risk factors.

Figure 5-10. Range of regional capacity surplus (shortfall) relative to a one-day-in-ten-year standard across a range of sensitivities



5.3.2.3 Statistical Reliability Metrics

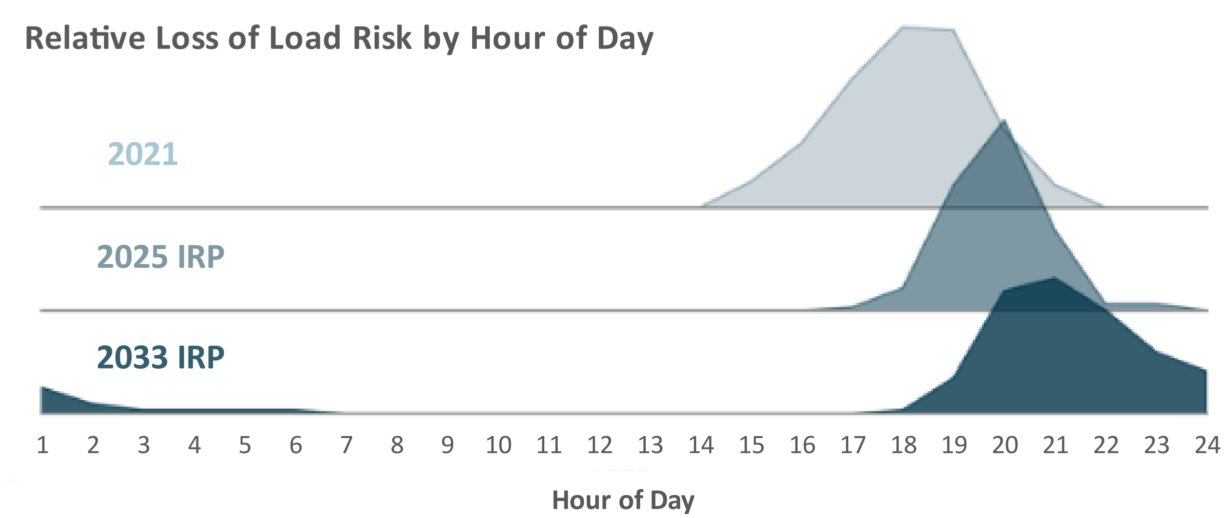
Table 5-7 summarizes the statistical metrics for the IRP portfolios. Under Base Case assumptions, both the 2025 and 2033 portfolios achieve an LOLE below the 0.1 days per year standard.

Table 5-7. Reliability statistics for the IRP portfolio scenario analysis

Metric	2021 Existing	2025 IRP	2033 IRP
Loss of Load Expectation *(days per year)*	0.15	0.04	0.01
Average Event Duration *(hours per event)*	3.0	1.9	1.2
Normalized Expected Unserved Energy *(parts per million)*	2.7	0.34	0.15
Effective Capacity Surplus (Shortfall) *(MW)*	**(225)**	**760**	**1,356**

While the near-term net load challenge in 2025 occurs during a narrow band during the late evenings, the mid-term and long-term net load challenge extends far into the night and into the early mornings, extending past the duration of short-duration storage resources. In Figure 5-11, this chart shows how the risk today's loss of load probability shifts from the early evening into the night in 2033, extends into the early morning. The shifting nature of the reliability risk impacts the marginal value of different technologies in the portfolios.

Figure 5-11.Increasing levels of solar and storage push the net peak and extend the relative risk of loss load



6 Risk Assessment

As the Southwest continues to rely on new technologies and face new risks associated with climate change, these uncertainties to resource adequacy and grid reliability intensifies. This section explores the variety of sensitivities and risks that could further impact the region's overall reliability.

6.1 Extreme Load Uncertainty & Climate Change Impacts

The prospect of increasing frequency and severity of extreme weather due to climate change represents a growing uncertainty in resource adequacy planning, as historical weather records do not serve as a reasonable basis for characterizing the probabilities of future events. This study directly accounts for the impacts of past warming trends in the development of simulated load shapes that are representative of today's climate, but additional uncertainty exists as the tails of the distribution will likely continue to shift in the coming decade.

To address this uncertainty, this study examines two sensitivities on more extreme load conditions that are intended to illustrate the potential impacts of further increases in extreme weather events. In the first sensitivity, the distribution of peak load conditions is scaled so that an extreme event that occurs once every five years today occurs once every other year in the future (tested in 2025 and 2033); in the second sensitivity, the distribution is scaled so that an extreme event that occurs once every ten years today occurs once every other year in the future (tested in 2033 only).

Table 6-1 shows the increase in peak load representing the abnormally hot years due to climate change. These increases in peak demand result in a direct increase the amount of capacity needed to maintain regional resource adequacy. Each 100 MW increase in median peak results in an additional need of 113 MW of effective capacity (100 MW plus the 13% reserve margin).

Table 6-1. Modeled increased peak loads due to climate change

Sensitivity	% of Current Median Peak	2025 Median Peak Load	2033 Median Peak Load
Base Case	100.0%	26,741 MW	31,787 MW
Increased Peak (1)	103.1%	27,570 MW	32,772 MW
Increased Peak (2)	104.5%		33,159 MW

Table 6-2 shows how these different levels of peak demand could impact the level of reliability in the region under the IRP portfolios. While the Base Case results indicate a small surplus of effective capacity in the IRP portfolios, the potential for more extreme peak demands could plausibly reduce or eliminate this apparent surplus over the timeline studied.

Table 6-2. Impact of peak demand sensitivities on level of reliability, IRP scenarios

	2025 IRP Portfolios		2033 IRP Portfolios		
Metric	Base	Increased Peak (1)	Base	Increased Peak (1)	Increased Peak (2)
Loss of Load Expectation *(days per year)*	0.04	0.12	0.01	0.04	0.08
Loss of Load Hours *(hours per year)*	0.07	0.23	0.02	0.10	0.20
Average Event Duration *(hours per event)*	1.9	1.9	1.2	2.3	2.4
Normalized Expected Unserved Energy *(parts per million)*	0.34	1.4	0.15	0.73	1.5
Effective Capacity Surplus (Shortfall) *(MW)*	**760**	**-99**	**1,356**	**574**	**163**

These sensitivities explore hypothetical changes to the level of peak demand in the region, and in doing so, explore a wide range of possible outcomes. Additional (and continuous) research will be needed to ensure that the characterization of probabilities of extreme weather events used to inform resource adequacy planning in the future reflect the best available climate science.

6.2 Battery Storage Performance

One of the most significant aspects of the changes in the region's projected portfolio of resources as represented by the IRP portfolios is the dramatic increase on battery storage over the analysis horizon. Recent technological advances and continued cost reductions provide cause for optimism, and yet: the projected quantities of installed capacity of battery storage – 3,000 MW by 2025 and 11,000 by 2033 – are profoundly large for a technology that is, as yet, largely untested at grid scale. In these early years, unexpected events may result in extended outages as utilities and regulators seek to understand the cause of performance failure. Such has been the case for APS' McMicken facility, where, after a 2019 fire, APS took the plant offline during an extended root cause assessment;[36] as well as for the 300 MW Vistra Energy Storage facility at Moss Landing, which overheated during high summer temperatures in 2019 and had not returned to service as of the publication of this report.

These types of events naturally raise questions of how reliably storage facilities will be available to supply the grid when it needs power most – and what the resulting impacts on overall resource adequacy may be if they cannot. A number of uncertainties – particularly acute in the early years of new technology commercialization – may impact the effectiveness of energy storage as a capacity resource:

+ **Outage rates:** one of the uncertainties associated with battery storage performance is the relative risk of experiencing plant outages; while manufacturer specifications indicate a low risk of plant

[36] https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Newsroom/McMickenFinalTechnicalReport.ashx?la=en&hash=50335FB5098D9858BFD276C40FA54FCE

outages, newly commercialized technologies can often experience unexpected outages for multiple reasons.

- **Performance under extreme heat:** the extreme summer temperatures of the Southwest create a difficult operating environment for electrochemical processes. In addition to potentially contributing to increased risk of outages, high temperatures could lead to degradation of output.
- **Dispatch uncertainties:** the dispatch of energy storage in the "Base Case" is an idealized representation of storage intended to maximize the capacity value of energy storage to the region; however, real-world operations of energy storage may deviate from this ideal dispatch. A missed opportunity to charge or a discharge that precedes the timing in which it is most needed could inherently limit the effectiveness of storage. Similarly, this study's assumption – that all batteries are operated to maximize value to the *region* – may differ from how individual utilities operate their devices to maximize value for their customers.

Because there is little empirical data to inform precise estimates of these impacts, this study explores a broad range of sensitivities that vary both the outage rates and the amount of duration available from battery storage devices. The impacts of these uncertainties on the reliability of the IRP portfolios is tested by adjusting specific storage-related inputs:

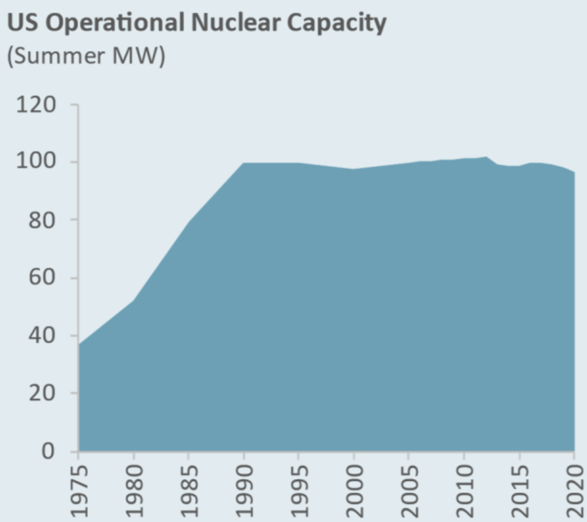
(1) Increased forced outages frequency
(2) Derated storage duration
(3) Combined forced outage frequency increase and storage duration derates

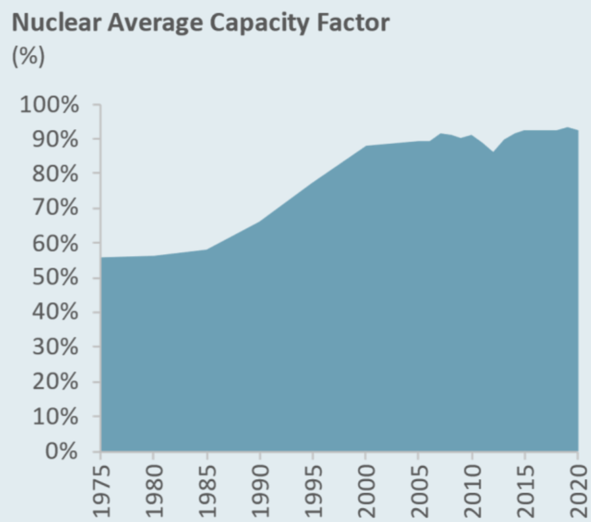
As has occurred for other new technologies in their early stages of commercialization, experience and a longer operational history should help mitigate the risks surrounding these uncertainties. As engineering and construction firms, plant operators, and maintenance crews gain experience and build collective knowledge of how to manage grid-scale storage assets effectively, potential high outage rates in initial years of implementation are likely to decrease over time. What this means is that the questions around performance and the risk of outages are most uncertain in the next five years while the industry achieves its initial phase of commercial development.

The results of the storage sensitivities tested in this study are shown in Table 6-3 (2025) and Table 6-4 (2033) under the IRP portfolios. The sensitivities highlight a wide range of possibilities: in 2025, under the most pessimistic sensitivity for battery performance, the expected frequency of loss of load would increase by more than a factor of two, and the amount of effective capacity in the region could be reduced by as much as 700 MW. Higher-than-anticipated forced outage rates in particular could contribute to more frequent loss of load events.

A Case Study of Learning by Doing in the Nuclear Industry

One instructive example of how new technology may improve in its performance as deployment increases – enabling "learning by doing" – is the nuclear power sector in the United States. Most of the nuclear plants in operations today were built in the 1970s and 1980s. In these early decades, capacity factors were much lower than today; however, as the industry matured, improvements in knowledge and experience have enabled most nuclear plants to run at high capacity factors.





Because nuclear plants are designed to operate as baseload facilities, the capacity factor provides a reasonable indicator of plant availability. A 1976 study of nuclear plant performance determined an average capacity factor for nuclear plants of 60%, concluding that the "lost capacity factor" could be attributed to scheduled outages and regulatory inspection (54%), forced outages (43%), and load following (1%).* Efforts to characterize the causes of these lower capacity factors point to a number of issues, including reliance on a limited number of suppliers, lack of design and engineering experience within the industry, and the limited experience of maintenance crews and plant operators.**

There are many reasons to be optimistic that "learning by doing" will occur more quickly for emerging technologies today than in the early years of nuclear power deployment; for instance, the more modular nature of technologies like battery storage will allow engineers and utilities to gain experience more quickly, and today's systems for performance monitoring and data collection are far more advanced than they were in the 1970s. Nonetheless, planners must consider performance uncertainty as technologies enter the market and plan for a broad range of performance possibilities.

* Komanoff, Charles. Power Plant Performance: Nuclear and Coal Capacity Factors and Economics. New York and San Francisco: Council on Economic Priorities. 1976.

** Joskow, Paul L. and George A. Rozanski. "The Effects of Learning by Doing on Nuclear Plant Operating Reliability." The Review of Economics and Statistics: 61(2). 161-168.

Table 6-3. Reliability statistics of different battery storage performance sensitivities, 2025 IRP scenario

	Base	90% Duration	80% Duration	10% FOR	20% FOR	10% FOR + 90% Duration	20% FOR + 80% Duration
LOLE (days/yr)	0.04	0.04	0.04	0.05	0.08	0.05	0.10
LOLH (hrs/yr)	0.07	0.07	0.07	0.10	0.15	0.11	0.18
nEUE (ppm)	0.34	0.38	0.45	0.55	0.85	0.61	1.00
Effective Capacity Surplus (Shortfall) (MW)	760	681	625	401	120	389	80

By 2033, the storage fleet accounts for roughly one quarter of the region's total effective capacity, which means performance risks have larger effects upon system reliability. The reliability effects of each type of storage derates are generally consistent across the two study years, but the importance of duration is magnified in 2033 when the portfolio relies more heavily on energy storage. Higher increased forced outage rates also increase the risk of reliability events. The results indicate that under scenarios where batteries are unavailable to provide power to the system when needed and limited in their duration of dispatch for either technical or institutional reasons, the portfolio may not be sufficient to maintain reliability.

Table 6-4. Reliability statistics of different battery storage performance sensitivities, 2033 IRP scenario

	Base	90% Duration	80% Duration	10% FOR	20% FOR	10% FOR + 90% Duration	20% FOR + 80% Duration
LOLE (days/yr)	0.01	0.02	0.04	0.02	0.09	0.05	0.29
LOLH (hrs/yr)	0.02	0.05	0.11	0.05	0.20	0.12	0.75
nEUE (ppm)	0.15	0.36	0.93	0.35	1.3	0.83	5.2
Effective Capacity Surplus (Shortfall) (MW)	1,356	950	430	817	2	428	**(598)**

6.3 Hydro Availability

The capability of hydroelectric generators can vary from year to year based on hydrological conditions—creating another dimension of uncertainty the region's resource adequacy. As mentioned in Section , most of the Southwest's hydro resources consist of shares of three large hydro projects operated by the federal government, totaling a nameplate capacity of 1,310 MW. In the base case, this study models the capability of the hydro system probabilistically, reflecting a possible range of different hydro conditions detailed in Technical Appendix A.

In these sensitivities, the available hydro energy supply is treated deterministically under two specific hydrological conditions: dry conditions, which are generally consistent with current drought conditions in the region; and critical conditions, which captures the impact of an even more severe drought. During a critically dry year, the low reservoir levels result in a 71% reduction in energy availability and a 55% reduction in maximum power output from May to September relative to normal conditions. A large part of this reduction is due to the assumption that, at these critical levels, it would no longer be possible to operate Glen Canyon Dam for power generation.

Table 6-5 summarizes how these specific conditions would impact the amount of capacity needed to ensure reliability within the Southwest region. Under "Critical" hydro conditions, the region's capacity shortfall increases by 478 MW of effective capacity relative to the Base Case; under "Dry" conditions, the capacity shortfall decreases by 215 MW relative to the Base Case. The approximately 700 MW difference in the regional capacity shortfall between dry and critical conditions is nearly 3% of the 2025 system peak. On a system at load-resource balance (i.e. a system at LOLE = 0.1 days per year), the loss of this amount of effective capacity would be enough to more than double the frequency of potential loss of load events (i.e. would increase LOLE to 0.2 days per year).

Table 6-5. Impact of different hydro conditions on 2025 residual regional capacity needs

	2025 Existing & Committed Portfolios		
	Base Case	Dry Hydro	Critical Hydro
Effective Capacity Surplus (Shortfall) (MW)	**-3,789**	**-3,574**	**-4,267**
Change from Base Case (MW)	-	+215	-478

These results highlight the important role of hydroelectric generation as part of the regional supply portfolio – and the attendant risks of potential sustained droughts that could leave the region in critical conditions. Predicting future hydro conditions beyond a near-term horizon – especially in light of the as-yet unknown impacts of climate change – presents a challenge for planners, yet the multi-year lead time for new resource procurement demands that planners consider its range of impacts.

These effects will vary by utility depending on the role of hydro in their portfolios. Utilities in the region who rely on these resources for a share of their capacity needs should plan proactively for the full range of future outcomes, lest they be caught unprepared and without recourse to cure a deficiency caused by drought conditions. Utilities that do not rely on these resources to meet their needs may not be impacted as directly; however, hydro resource availability will have impacts on wholesale markets, and critical conditions could reduce these utilities' opportunities for short-term transactions that may be needed in real-time operations to maintain reliability.

6.4 Natural Gas Resource Performance

Gas generators tend to see higher rates of failure during extremely high temperatures. While southwest utilities are no strangers to the heat, climate change continues to push the temperature higher, which would increase the likelihood of more frequent gas outages. Under this risk assessment, E3 explores how the region's reliability would change if a regional heat wave increased the likelihood of higher forced outage rate across all natural gas resources.

In this sensitivity, all natural gas combined cycles and combustion turbine power plants experience random outages twice as frequently as under Base Case assumption, resulting in forced outage rates in the range of 6-10% for natural gas generators. Table 6-6 summarizes the impacts of higher natural gas outage rates in the 2025 and 2033 IRP portfolios. In both cases, more frequent outages of natural gas generators reduces the reliability of the portfolio.

Table 6-6. Reliability statistics for High Gas Outages sensitivities

	2025 IRP Portfolios		2033 IRP Portfolios	
Metric	Base Case	High Gas Outages	Base Case	High Gas Outages
LOLE (days/yr)	0.04	0.08	0.01	0.02
LOLH (hrs/yr)	0.07	0.17	0.02	0.07
Normalized EUE (ppm)	0.34	1.0	0.15	0.55
Effective Capacity Surplus (Shortfall) (MW)	**760**	**59**	**1,356**	**713**

Considering that the probability of natural gas generator outages will impact the level of reliability achieved in the region, utilities should ensure that their planning assumptions are aligned with expectations for availability under the extreme temperatures of the Southwest; similarly, any maintenance or weatherization measures that improve likelihood that gas generators may be available as extreme temperatures become more frequent would provide a reliability benefit to the region.

6.5 Natural Gas Supply Vulnerability

While this study does not examine this risk quantitatively, previous efforts have characterized the nature of the reliability risk to the region stemming from potential large-scale disruptions to the supply of natural gas. In 2018, the Western Electricity Coordinating Council sponsored a study of gas-electric interdependence across the Western Interconnection[37] to identify scenarios where gas supply disruptions due to extreme weather events or contingencies could jeopardize reliable electricity operations. The study reached three findings specific to the Southwest region:

+ Most gas generators in the Southwest region rely on firm transportation service for delivery of natural gas, making the region less susceptible to supply disruption than other parts of the country where large portions of the natural gas fleet rely on interruptible service (e.g., the mid-Atlantic and New England regions).
+ The possibility of rupture of a mainline section of a major pipeline between the Permian Basin in Texas and downstream natural gas consumers would almost surely result in significant loss of load

[37] Wood Mackenzie, 2018. *Western Interconnection Gas Electric Interface Study*. https://www.wecc.org/Reliability/Western%20Interconnection%20Gas-Electric%20Interface%20Study%20Public%20Report.pdf

in the Southwest and California if it occurred during the summer peak season; however, this type of event was classified as a very low probability event due to "the strong overall safety record of the pipeline as well as the security from having four separate pipelines."

+ A wellhead freeze-off in the Permian Basin – such as the events that occurred in 2011 and 2021 – presents a much lower risk to electric reliability than in other regions due to lower winter demand and the likelihood that surplus capacity resources in other regions could effectively compensate for the loss of capability in the Southwest; nonetheless, reliability could be compromised in this scenario and is an elevated risk should the Aliso Canyon gas storage facility in California close.

The risk identified in the freeze-off scenario is reminiscent of conditions that occurred in February 2011, when a winter storm across the Southwest region ultimately resulted in small amounts of load shedding for a number of utilities in the Southwest. These load shedding events were attributed to several causes, including plant failures driven by extreme weather conditions and natural gas supply shortages resulting from a wellhead freeze-off in the Permian Basin.

Over the study period, the region's reliance on natural gas generators to meet resource adequacy needs is not projected to change significantly: the summer capacity of the fleet was 16,892 MW in 2021 and, due to a combination of additions and retirements, decreases only slightly to 16,278 MW in 2033. The direct implication of this small change is that the region's risk profile to reliability risks resulting from natural gas disruptions will not likely change substantially in the coming decade.

6.6 Regional Market Assistance

The ability to purchase surplus power from neighboring regions will have some impact on the level of reliability achieved in the Southwest; quantifying this impact precisely is difficult because of the range of different institutional, physical, and economic factors that could affect future market dynamics during times of need in the Southwest. This sensitivity nonetheless provides an illustrative assessment of the role neighboring markets might contribute to the region's efforts to preserve reliability.

Table 6-7 compares reliability statistics under the Base Case assumptions (no external market support) and the Regional Support sensitivity. The availability of external market support results in an improvement of the reliability of the portfolios examined herein; under the specific assumptions used in this sensitivity, the frequency of loss of load events is reduced to near zero.

Table 6-7. Summary statistics for the regional market support sensitivity

	2025 IRP Portfolios	
Metric	**Base Case**	**Regional Support**
LOLE (days/yr)	0.04	0
LOLH (hrs/yr)	0.07	0
Normalized EUE (ppm)	0.34	0
Effective Capacity Surplus (Shortfall) (MW)	**760**	**2,139**

The extent to which this effect can – or should – translate to a reduction in the need for physical capacity within the Southwest is a secondary question. The reliability benefit illustrated in this sensitivity results from the load and resource diversity across a broader region, which enables sharing of resources built to meet the resource adequacy needs of one region with another when those resources are not needed. While such a sharing of resources is theoretically possible, there are a number of reasons to be cautious in treating external markets as capacity resources in the absence of a formalized capacity pooling framework:

+ **Development risk in neighboring regions:** relying on the external market to meet a share of future resource adequacy needs requires an understanding of how the future load-resource balance in those regions will evolve. At the moment, both California and Nevada face significant needs for new capacity over the next five years; if resources cannot come online in the quantities identified due to supply chain challenges, interconnection delays, or other factors, neighboring regions may not have sufficient capacity to share significant quantities in the market during constrained periods, and Western energy markets may remain tight.
+ **Operational risks of energy-limited resources:** as neighboring regions come to rely more heavily on energy storage and other energy-limited resources to meet increasing portions of their resource adequacy needs, their system operations will change dramatically, and the nature of opportunities to share resources will change fundamentally. Historically, there has been little to no "opportunity cost" to sharing unutilized firm resource capacity with a neighbor when not needed by its primary owner/offtaker. However, because of their finite durations, sharing of unused storage resources comes with an "opportunity cost": dispatching storage to meet a neighbor's needs may prevent its owner from relying on that resource to meet its own needs at a later point in time. Because of this opportunity cost, utilities in neighboring regions may not sell "surplus" storage capacity into tight markets in the Southwest if it could jeopardize reliability on their own system .
+ **Institutional risks:** the choice to treating neighboring markets as capacity resources enabled by transactions in short-term energy markets – sometimes known as "front-office transactions" – poses institutional risks to market participants: until energy is delivered to their system, they are relying on a system of financial commitments among counterparties to meet their needs. In some cases, this may not translate to physical delivery of power at the moment it is needed. The experience of the Nevada Power Company during the August 2020 western heat wave provides a cautionary tale in this respect:

  > "On Tuesday August 18, 2020, and Wednesday August 19, 2020, variances occurred between the day-ahead planning forecasts and actual operating conditions. For example, some energy supply procured in advance was no longer deliverable by counterparties due to curtailments of both firm and non-firm energy products. Curtailments occurred throughout each day with little to no advance notifications, sometimes providing notice of curtailment just minutes before scheduled delivery or during the delivery period."[38]

  One of the reasons that this might occur is if utilities' front-office transactions exceed the physical capability of the system. This very set of circumstances – a concern that collective reliance across

[38] Nevada Power Company, 2020. Comments of Nevada Power Company and Sierra Pacific Power Company in Docket 20-08014. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2020_THRU_PRESENT/2020-8/5132.pdf.

the region on front-office transactions was too large – sparked the conception of an asset-backed resource adequacy program in the Northwest, an initiative that has since evolved into the Western Resource Adequacy Program.

Overcoming these obstacles to harvest benefits of load and resource diversity across a much broader geographic footprint – as has been done in a number of eastern markets – is certainly possible and may in fact proceed with the Western Resource Adequacy Program, but until such institutional infrastructure is well-established, relying on the market as a capacity resource remains a risk to resource adequacy.

This risk is further compounded by the prospect that climate change may be contributing to increasingly frequent extreme weather events with a broad regional scale. Changes in weather system fundamentals due to climate change have already had apparent impacts on extreme conditions across the West. The Western heat wave of August 2020 stands out in recent memory as an example of a period in which extreme heat impacted a broad region across the Western Interconnection, causing multiple balancing authorities to issue warnings. While CAISO was the only one to experience load shed, five other BAs issued energy emergency alerts during the same few days.[39] While there are few such events in the extended historical weather record, the prospect that these could occur more frequently increases the risk of relying on neighboring regions.

6.7 Timing of New Resource Additions

Most of the scenarios analyzed in this study assume that the new resources included in utilities' plans will come online exactly according to the timelines specified in those plans. This sensitivity examines how a one-year delay in the addition of new resources identified in the utilities' IRPs would impact regional reliability in 2025. The utilities' plans currently include nearly 3,500 MW of new installed capacity expected to come online between the summers of 2024 and 2025.

Table 6-8. Cumulative installed capacity additions between 2021 and 2025

	Cumulative Installed Capacity Additions, 2021-'25 (MW)		
	Base Case	One Year Delay	Difference
Natural Gas	1,541	836	-705
Geothermal	-	-	-
Solar	8,186	6,771	-1,415
Wind	1,358	805	-553
Storage	3,459	2,589	-870
DR	385	322	-63
Total	**14,794**	**11,313**	**-3,606**

[39] WECC, 2021. *August 2020 Heatwave Event Analysis Report*. https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.

Table 6-9 shows the impact of a one-year delay in the addition of new resources to regional reliability. The impact is significant: the 3,500 MW installed capacity of new resources added in 2025 accounts for 1,770 MW of effective capacity – or roughly 6% of the region's total reliability needs in that year. Without these resources online, the expected frequency of loss of load events increases by a factor of ten; the LOLE in the sensitivity is approximately 0.5 days per year. This dramatic increase is a result of the exponential relationship between capacity and reliability risk: increasing shortfalls below the region's capacity needs result in rapid escalation of the risk to reliability.

Table 6-9. Comparison of regional reliability metrics for 2025 IRP Base Case & One-Year Delay sensitivity

	2025 IRP Portfolios		
Metric	**Base Case**	**One Year Delay**	**Difference**
LOLE (days/yr)	0.04	0.5	+0.45
LOLH (hrs/yr)	0.07	1.0	+0.93
Normalized EUE (ppm)	0.34	6.1	+5.8
Effective Capacity Surplus (Shortfall) (MW)	**760**	**-1,010**	**-1,770**

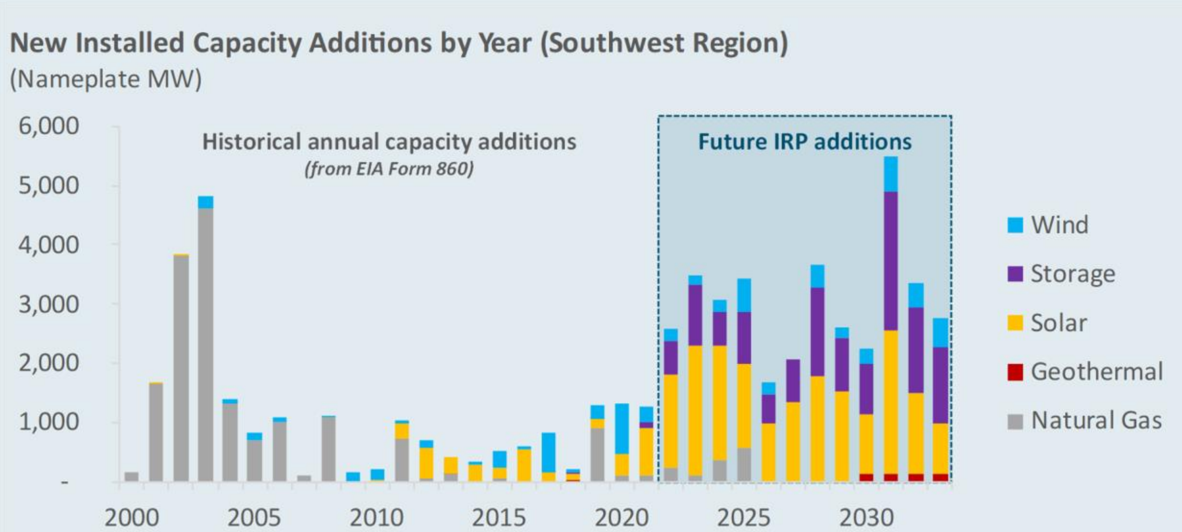
The magnitude of the impact illustrated in this sensitivity underscores the importance of timing new additions to match the region's increasing needs. The total amount of new installed capacity included in utility plans in the next decade totals nearly 40,000 MW. The implied rate of new capacity additions – over 3,000 MW of new installed capacity per year – is nearly unprecedented in the history of the Southwest region. The development timelines for resources that can fulfill that need – including siting and permitting processes, transmission studies, competitive solicitations, regulatory approvals, and engineering, procurement and construction – span multiple years, underscoring the urgency of prompt action to ensure needs may be met throughout the decade.

An even worse scenario might occur if delays in bringing projects online extend to two or more years. Because of the rapid rate of anticipated construction, delays spanning multiple years could further enlarge this deficit. These deficits would be very difficult to overcome, potentially leading to a situation where reliability risk is elevated for a decade or more. While this risk might seem remote in normal times, supply chain disruptions, materials shortages and a tight labor market are already impacting project timelines across the country.

While this sensitivity illustrates the impact of project delays for 2025, this risk will be present throughout the next decade as loads grow and resources retire. To avoid the future outcome shown in this sensitivity, utilities should account for reasonable possibilities of delays and project cancellations when assessing need and timing the procurement of new resources. This may reasonably lead to an outcome where, during periods of rapid change such as the next decade, utilities' actual reserve margins exceed the levels deemed strictly necessary to meet resource adequacy requirements in order to mitigate reliability risks associated with rapidly growing needs and unexpected changes in project development timelines. The

A historical perspective on the rate of new capacity additions in the Southwest

The Western Energy Crisis of 2001 was followed by one of the most rapid periods of new resource development in the history of the Western Interconnection, as utilities around the region invested in new natural gas generation in response to acute reliability concerns. In the Southwest, nearly 10,000 MW of natural gas capacity was built between 2001-2004; most of these resources continue to operate today in support of utilities' resource adequacy needs. Since that time, the pace of new resource development in the region has been comparatively moderate. However, looking forward, the amount of new capacity reflected in utilities' plans represents a surge in the rate of new capacity additions and a sustained rate of new resource development that approaches the level experienced 20 years ago.



need to mitigate timing-related risks during periods of transition has historically been recognized by regulators as justification that actual reserve margins may reasonably exceed minimum requirements.[40,41]

One of the direct corollaries to this recommendation is that any replacement resources for planned retirements should be brought online in advance of the scheduled retirement to accommodate the risk of possible delays; a failure to account for some margin in a period of rapid transition could lead to either (a) a degradation of reliability, or (b) the need to extend the lifetime of retiring resources. Either of these outcomes could pose a significant setback to utilities' efforts to transition affordably to low-cost, low-carbon portfolios.

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[40] A stipulation approved by the New Mexico Public Regulation Commission in Case No. 08-00305-UT in 2008 noted that "The Signatories acknowledge that PNM's actual reserve margin may temporarily deviate from the planning reserve margin due to unexpected changes in load or imbalances caused by the magnitude of new resource additions to meet load growth, system requirements and renewable portfolio standards."

[41] In D-04-01-050, the California Public Utilities Commission's adopted a 15-17% planning reserve margin requirement, noting: "We recognize that there is an inherent 'lumpiness' to resource additions and the utilities may end up with reserve levels above 15% depending upon the timing of resource additions." (see https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/33625.pdf)

6.8 Summer Stress

In a final sensitivity explored in this study, assumptions from several sensitivities are combined to create a worst-case "Summer Stress" sensitivity. The assumptions reflected in this case include:

+ Median peak load scaled to a "1-in-5" condition;
+ Forced outage rates for natural gas generators doubled relative to the Base Case;
+ Battery storage outage rates modeled at 10% and duration derated by 10%; and
+ "Critical" hydrological conditions.

Combining these factors together results in a large degradation of reliability, yielding a system that is clearly not reliable according to traditional standards: by 2025, the IRP portfolios would fail to serve loads an average of 1.3 days every year – over ten times more often than envisioned by the "one day in ten year" standard. The effect is of a similar magnitude in 2033.

Table 6-10. Summary results for the "Summer Stress" sensitivity, 2025 IRP

	2025 IRP Portfolios		2033 IRP Portfolios	
Metric	Base Case	Summer Stress	Base Case	Summer Stress
LOLE (days/yr)	0.04	1.3	0.01	1.3
LOLH (hrs/yr)	0.07	2.6	0.02	3.4
Normalized EUE (ppm)	0.34	16	0.15	25
Effective Capacity Surplus (Shortfall) (MW)	**760**	**(1,913)**	**1,356**	**(1,971)**

While the likelihood that all of these risks converge to produce this result is small, the results are instructive for planners to consider. First, it illustrates the compounding effect of stressors to reliability. Individually, each of the sensitivities included in the "Summer Stress" case had moderate impacts on the level of reliability achieved; across the individual sensitivities, LOLEs range from 0.04 to 0.10 days per year. Together, the effect is multiplicative, and the risk of experiencing loss of load events increases from a rare possibility to a near certainty. This result underscores the importance of continuous efforts to refine data and information used to assess reliability. Efforts to improve confidence in the assumptions used in these types of analysis can support increased confidence that resource adequacy assessments are appropriately considering the risk factors that can contribute to reliability events.

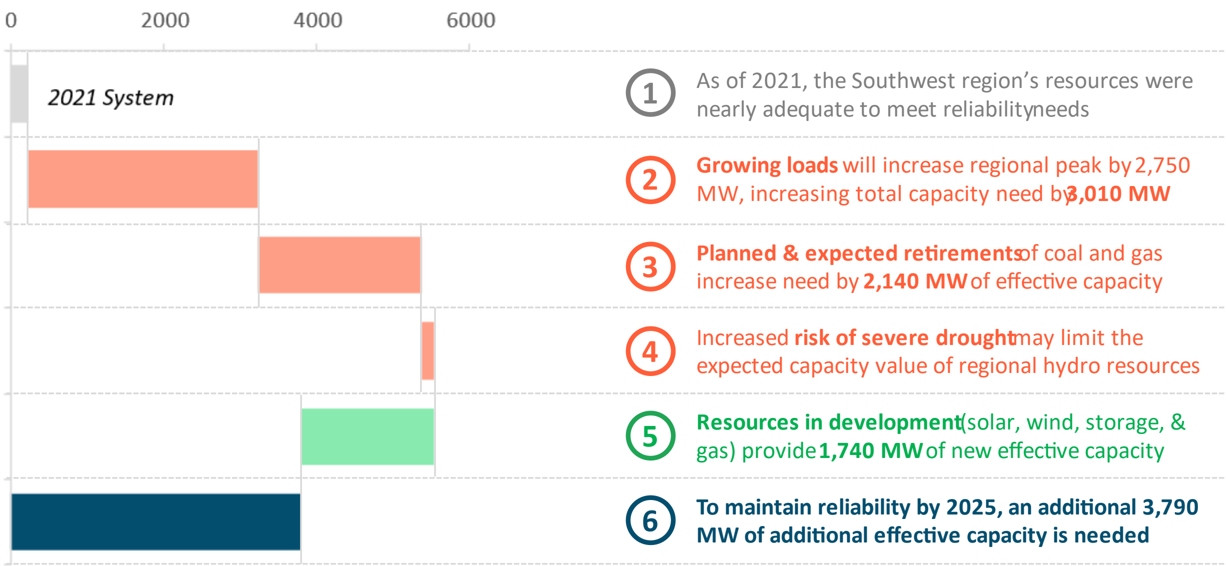
7 Conclusions

7.1 Key Findings

1. Load growth and resource retirements are creating an urgent and significant need for new resources in the Southwest region

Between 2021 and 2025, utilities in the region anticipate growth in electric loads of roughly 2.4% per year, increasing the regional coincident peak demand from 24,000 MW to 26,700 MW. Over the same horizon, utilities have developed plans to retire roughly 1,200 MW of coal capacity and 1,300 MW of natural gas capacity. In a system that is already close to load-resource balance in 2021, the compound effect of these two changes – plus the potential effects of increased drought risk on hydro production – create a total need for new effective capacity of roughly 5,000 MW. Resources under development today, which comprise a mix of solar, storage, wind, and natural gas, are together capable of meeting a portion – but not all – of this deficit. The remaining gap – summarized in Figure 7-1 – amounts to an additional 4,000 MW of effective capacity. In a system that is already on the cusp of an acceptable level of reliability today, the ability of the region's utilities to preserve reliability over the next few years will depend on their ability to bring new resources online in a timely manner to address this growing shortfall.

Figure 7-1. Changes in the load-resource balance of the Southwest region, 2021-2025



Notes

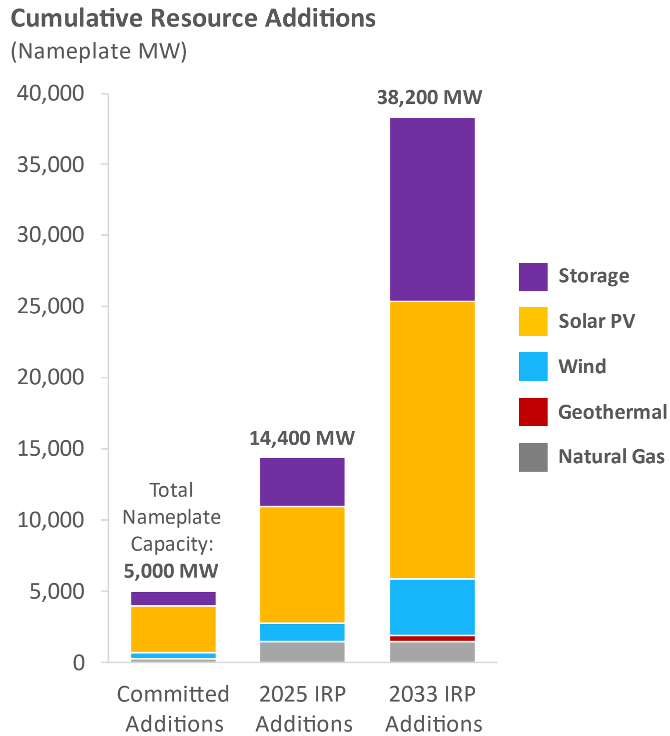
1. "Effective capacity" measures a resource's contribution to resource adequacy relative and is typically less than its nameplate capacity; the amount of new nameplate capacity needed to ensure resource adequacy will exceed – likely by a multiple of three to four times – the amount of new effective capacity needed
2. Resources in development within the region include solar (3,281 MW), storage (1,040 MW), wind (455 MW), and gas (228 MW)

The need for new capacity will continue to grow beyond 2025, driven largely by the compound effects of load growth and resource retirements. If the growth as projected by the region's utilities continues, peak demand could reach 31,700 MW by 2033. At the same time, the total amount of coal and natural gas capacity expected to retire between 2021 and 2033 is 6,400 MW, roughly one third of the total coal and natural gas capacity serving the Southwest region today. Due to this combination of changes, the amount of new effective capacity needed within the region would grow to 13,000 MW.

2. Utilities' current resource plans have identified enough resources to maintain regional reliability over the next decade

Utilities' integrated resource plans, each designed to achieve a balance between affordability, reliability, and sustainability, identify plausible portfolios of future resources to meet anticipated needs. In addition to the 5,000 MW of resources already under development, the region's utilities' plans include a total of 10,000 MW of additional nameplate capacity, most of which is solar and battery storage. By 2033, total additions of nameplate capacity exceed 35,000 MW. The large majority (97%) of installed capacity additions planned over the next decade are clean, non-emitting resources. The breakdown of these capacity additions is shown in Figure 7-2. Notably, the amount of *installed* capacity needed to maintain reliability far exceeds the amount of *effective* capacity needed; this is an expected result due to the inherent limits of variable and energy-limited resources to contribute to system resource adequacy needs.

Figure 7-2. New resource additions included in regional utilities' IRPs

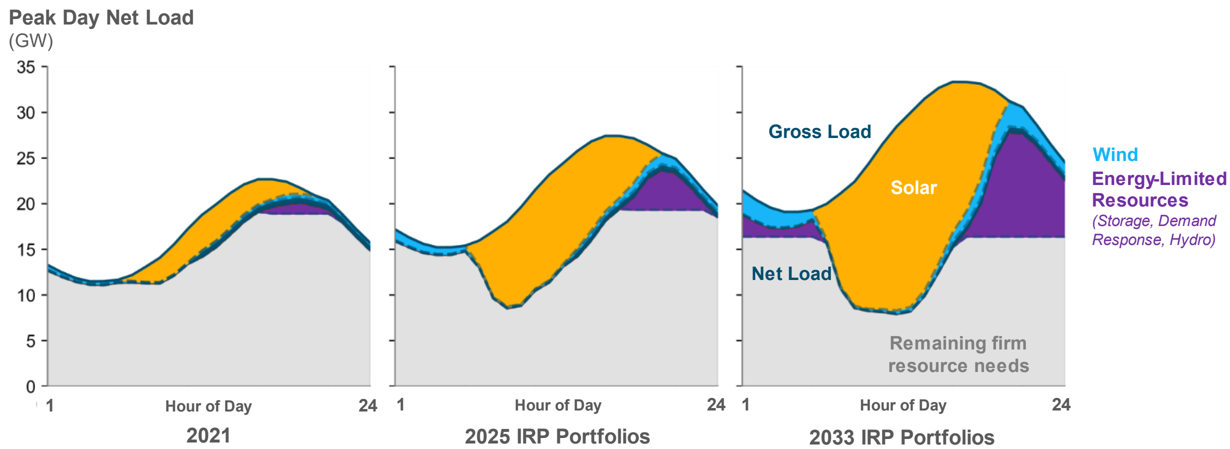


This quantity of new resource additions is found to be sufficient to meet a regional reliability standard of "one day in ten years". If all resources included in utility IRPs come online during the timeframes identified, the region will maintain a small surplus of effective capacity over the 2021-2033 time horizon under the Base Case. This finding notwithstanding, utilities' individual standards for resource adequacy will continue to govern their future resource needs, and the degree to which each utility's respective plan achieves a satisfactory degree of reliability should ultimately be assessed based on their ability to serve their loads.

3. A significant share of long-term resource needs is expected to be met with solar and storage, which together are well-suited to meet a large portion of the region's loads on summer peak days

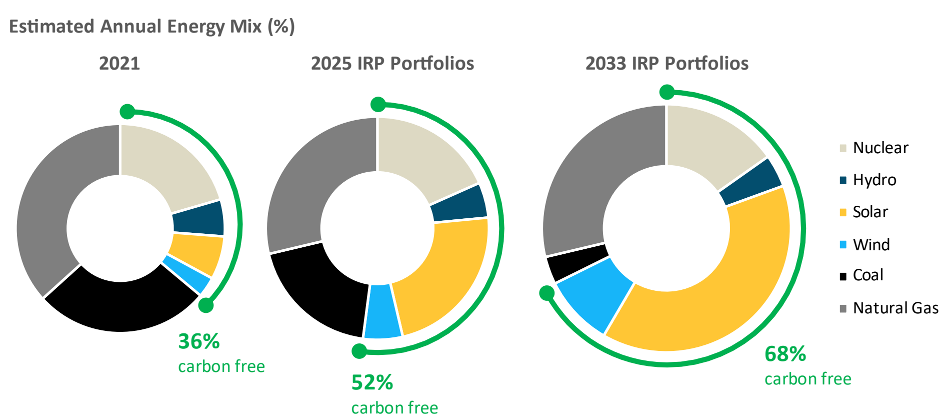
By 2025, the aggregate portfolio of variable and energy-limited resources – predominantly solar and storage – will provide for roughly 25% of the region's needs for effective capacity; by 2033, this figure will increase to nearly 50%. This transition is illustrated in Figure 7-3, which depicts the role of variable and energy-limited resources on a typical summer peak day in the Southwest region in each of the snapshot years examined in this study. Assuming idealized performance of energy storage resources, the combination of solar and energy storage is particularly effective and well-suited to meet a large share of the Southwest region's resource adequacy needs. On a typical summer peak day, solar produces at high capacity factors throughout the day, while storage resources – charged during periods of surplus generation – provide generation during the evening net peak and into the night.

Figure 7-3. Increasing roles for variable and energy-limited generation in meeting resource adequacy needs in the Southwest



It is worth noting that while the contribution of variable and energy-limited resources to system resource adequacy needs is projected to become significant in utilities' IRP portfolios, their respective shares of the regional energy mix will be even larger. Figure 7-4. Annual energy mix achieved under utility IRP scenarios highlights the evolution of the region's annual energy mix should the utilities execute upon their IRPs. By 2033, utilities' IRPs rely on solar (along with energy storage to support its integration) to supply 40% of annual energy needs; total carbon-free annual generation will account for nearly 70% of annual energy needs. This reflects an important axiom in the transition to a highly renewable electricity system: variable resources' share of the annual energy mix – and by extension, their impacts on greenhouse gas emission – will grow more quickly than their relative contributions to resource adequacy needs.

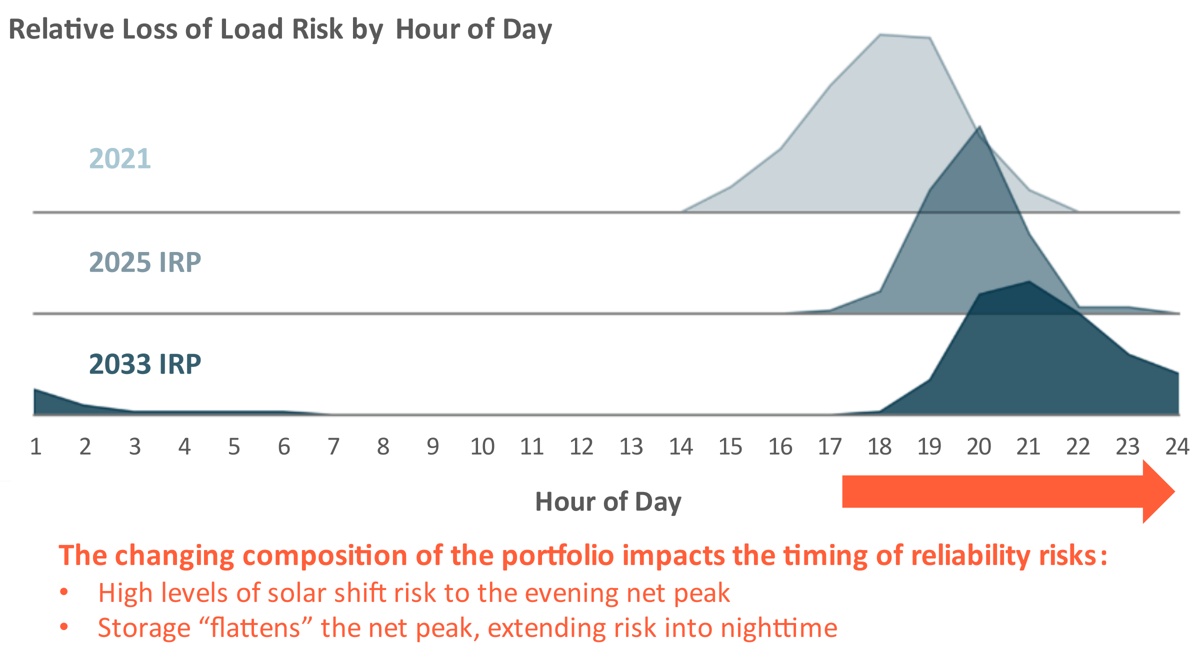
Figure 7-4. Annual energy mix achieved under utility IRP scenarios



4. The Southwest will continue to rely on a large quantity of "firm" generation resources to maintain resource adequacy; the region's remaining nuclear and natural gas resources will be crucial to meeting the need for firm resources through the study horizon and beyond

One of the profound consequences of the region's increasing reliance on solar and storage resources is that the timing of the greatest reliability risks will change. By 2025, the evening "net peak" will become more constraining than the historical late afternoon peaks due to saturation of daylight hours with solar energy. Deployment of energy storage at scale will further extend the constraining periods into the evening and nighttime hours. This transition is illustrated in Figure 7-5. The changing profile of reliability risk in the Southwest as the region transitions to higher penetrations of solar and storage below.

Figure 7-5. The changing profile of reliability risk in the Southwest as the region transitions to higher penetrations of solar and storage



As this transition occurs, the effectiveness of incremental solar and energy storage resources in their contributions to resource adequacy will diminish; this dynamic is reflected in their declining marginal ELCCs. By 2033, the marginal capacity value of solar is roughly 10%; of four-hour storage, 40%.

The changing character of this risk highlights the need for resources that are capable of delivering energy to the system for sustained periods from early evening until morning. For this reason, conventional firm capacity resources will continue to play a crucial role in meeting resource adequacy needs alongside a burgeoning portfolio of renewable, storage, and demand-side resources. Through the time horizon considered in this study, the region's remaining nuclear and natural gas generators, which total nearly 20 GW of installed capacity, will be needed to fulfill this crucial role.

5. Substantial reliability risks will accompany the transition of the region's electricity resource portfolio; managing and responding to these risks will require continuous efforts to refresh resource adequacy planning as more information becomes available and utilities gain more experience operating new resource portfolios

The most significant uncertainties and risks that could contribute to increased reliability risks include:

+ **Climate impacts:** climate change will continue to shift the distribution of possible weather conditions in the coming decade. But not only is the weather itself an uncertainty; how its extremes will impact the electricity system is as well. Weather impacts the electricity system in many ways – it affects the level of electric demand, wind and solar production patterns, thermal plant efficiency, hydrological conditions – and unprecedented extremes may have unanticipated impacts in this complex system.
+ **Battery performance:** battery storage resources are in early stages of commercialization at grid scale, and operators have limited experience with them – particularly in climates as harsh as the Southwest. This study relies on an idealized set of assumptions regarding performance, including low outage rates and dispatch that is aligned with times of greatest needs. In reality, performance risks could manifest in numerous ways, including higher-than-expected frequencies of unplanned outages, degradation of output under the extreme temperatures of the desert, or operations that fail to capture the maximum capacity value of the storage. Until engineers, construction, maintenance teams, and operators gain the necessary real-world experience to inform design and operations, planners should be cautious not to overstate their confidence in the performance of nascent technologies in resource adequacy planning.
+ **Renewable variability:** as the region transitions to higher levels of wind and solar, weather conditions will have a more direct impact on the availability of generation. While the characteristic production patterns of these resources are generally well-understood, the risk remains that the potential for sudden, large drops in renewable energy output and the potential for extended periods of low renewable energy production.
+ **Natural gas fuel security:** the interstate natural gas pipeline system does not operate to the same reliability standards as the electricity system, and fuel deliveries have been interrupted during extreme cold weather events. While this study does not examine these risks quantitatively, the fact that the amount of natural gas generating capacity remains relatively constant throughout the analysis horizon suggests that the same vulnerabilities identified in previous studies – pipeline ruptures and wellhead freeze-offs – will continue to pose risks to regional electric reliability through the coming decade.
+ **Timing & development:** meeting regional reliability needs in the next decade will require the addition of thousands of megawatts of new installed capacity each year. The processes surrounding new resource development – including siting and permitting; transmission interconnection studies; competitive solicitations and contract negotiation; regulatory approval processes; and engineering, procurement, and construction – require multiple years and are subject to risks of delay. Failure to bring resources online successfully before they are needed could compromise reliability and create a compounding deficit in a region where loads (and needs) are growing quickly. Utilities, regulators, stakeholders and developers will all share responsibility for working cooperatively to achieve this significant buildout.

7.2 Recommendations

This analysis finds that utilities' IRPs in aggregate will position the region to meet regional resource adequacy needs. In the absence of any systemic deficiency that can be traced to current planning conventions, this study concludes that no immediate changes to utility planning practices are needed to maintain reliable electric service.

This finding notwithstanding, utilities should continue to advance their resource adequacy planning practices to take advantage of new information and modeling techniques. These improvements will enable utilities to mitigate the risks identified herein and improve their efforts to balance planning for reliability portfolio alongside affordability and sustainability objectives. Most importantly, utilities should implement the resource adequacy planning "best practices" as identified in this study to the extent practicable, including:

+ **Assess the need for capacity using a probabilistic analysis framework** that captures the range of potential energy demands under an increasingly volatile climate and should update this analysis periodically as new information becomes available or as load shapes change.
+ **Apply an ELCC methodology – or similar technique – to assess the capacity value of all resources** in their portfolios on an equitable basis, capturing all of the risks and limitations to resource availability that are well-understood and quantifiable.

Additionally, in recognition of the uncertainties and associated risks identified in this report, utilities should regularly update inputs and assumptions in their resource adequacy planning.

+ **Ensure load forecast captures plausible weather conditions that reflect the best available climate science.** The upward climate trend and associated changes to the distribution of extreme weather conditions will have major implications on the abilities of the utilities' portfolios to supply their needs to an acceptable level of reliability.
+ **Align planning assumptions used to characterize each resource with expectations for performance under extreme heat.** The extreme heat conditions that drive resource adequacy challenges in the Southwest region may also impact the availability of generation, both through increased risk of plant outages and degradation of plant output. Utilities should ensure their planning reflects an understanding of these impacts for all types of resources; to the extent these effects are material, they could represent a correlated risk to resource adequacy.
+ **Gather and incorporate real-world information on performance of emerging technologies.** In the absence of historical data, performance assumptions for nascent technologies like battery storage are often idealized in resource adequacy modeling. Replacing idealized assumptions with real-world performance data will improve utilities' abilities to value the capacity contribution of these resources accurately. A centralized database with records of battery storage outages (such as NERC's Generation Availability Data Set for other technologies) would provide significant value to utilities' planning efforts throughout the country.

Finally, in recognition of the increasing systemic threats posed by catastrophic extreme weather events and common mode failures – both of which are difficult to incorporate into a probabilistic analysis framework – utilities should supplement probabilistic resource adequacy studies with resilience planning studies that examine the potential consequences of extreme weather and/or system contingencies.

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