Resource Adequacy Planning and Analysis:
Investigation of Potential Best Practice RA Approaches to Account for Increasing Penetrations of Renewable Energy Resources, Climate Change, and Extreme Weather

Proceeding 22M-0342E

Nicholas Garza
Research and Emerging Issues
Colorado Public Utilities Commission

November 30, 2022

Disclaimer

The views expressed in this report do not necessarily represent the views of the Public Utilities Commission or the Commissioners. This report was prepared by staff in the REI work unit of the PUC, not by Trial Staff, Advisors, or Commission Counsel.

About Research and Emerging Issues

The Research and Emerging Issues Section advances policy discussions that inform the Commission concerning current and emerging issues impacting regulated utilities, service providers, and consumers. This work unit accomplishes this mission by initiating, facilitating, coordinating, and performing objective and balanced policy research and education.

Outline

List of Figures

1. Background and Purpose: Reports of Diminishing Resource Adequacy in the West

Resource adequacy is the planning, procurement, and performance process that forecasts future demand, procures the necessary supply resources to meet that demand, and compensates resources for performance. The Western Electric Coordinating Council (WECC) provides an annual assessment of resource adequacy to identify reliability risks facing the Western Interconnection over the next ten years. In its annual assessment, the council assesses the projected load and generation changes from each balancing authority within its jurisdiction. In December 2021, the WECC released its "2021 Western Assessment of Resource Adequacy".[1] The report warns that by the end of the decade, there could be up to 598 total hours of high loss of load potential, with capacity shortfalls reaching as much as 5.3 GW in the summer months. By 2025 the entire interconnection will likely be unable to meet the North American Electric Reliability Corporation's (NERC) reliability criteria.

In May 2022, NERC released its annual "Summer Reliability Assessment," an annual report that identifies and assesses areas of concern regarding the reliability of the North American bulk power system for the upcoming summer season.[2] In the report, NERC warned of increased reliability risks across the Western United States due to both drought conditions that will limit the availability of hydropower resources and extreme heat events that could increase demand for electricity above planning reserve margin levels. In addition, all regions across the West are experiencing supply chain issues straining new resource and transmission projects while at the same time planning to retire existing coal generation. Lastly, NERC highlights the system vulnerabilities to an above-normal risk of wildfire caused by extreme weather. Transmission outages caused by proximity to active wildfires can pose significant risks to grid reliability. Indirectly, wildfire smoke coverage can also impact resource availability from utility-scale and rooftop solar PV.

In California, the California Independent System Operator (CAISO) announced that the state could see an electricity supply shortfall of 1,700 MW this summer. The scenario depicted by officials is identical to the August 2020 heat wave that caused rolling blackouts after a supply shortfall could not meet net demand. Officials also warned that extreme weather and wildfires could further increase demand and reduce resource availability via either capacity de-rates or transmission outages, increasing the supply shortfall to 5,000 MW. On another front, global supply chain issues have affected 600 MW of new capacity additions in California this year, and the supply shortfall will increase in the coming years. The Commerce Department's solar tariff investigation continues to overshadow the industry despite a temporary 24-month stay on tariffs.

In New Mexico, Public Service Company of New Mexico (PNM) announced earlier this year that it could face a 3.4% supply shortfall this summer. The New Mexico Public Regulation Commission then issued an order allowing the 1,684 MW San Juan coal plant to operate past June 30, its initially scheduled retirement date. PNM has been experiencing supply chain issues with new additions to replace the retired coal capacity. The problems in New Mexico are likely to extend to the summer of 2023 when the utility will lose one of its leases from the Palo Verde nuclear plant in Arizona. A study by Energy + Environmental Economics (E3) looked at resource adequacy in the region over the next decade and found a 3.8-GW capacity

[1] Western Electric Coordinating Council. (December 2021). *2021 Western Assessment of Resource Adequacy*. https://www.wecc.org/Administrative/WARA%202021.pdf

[2] North American Electric Reliability Corporation. (May 2022). *NERC Summer Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf

shortfall due to increased demand, lessening availability of hydroelectric resources due to drought, and fossil capacity retirements.[3] E3 further found that new planned resource procurements would not be sufficient to meet expected demand.

In May 2022, PJM, the Regional Transmission Organization (RTO) that services 13 states and the District of Columbia in the Eastern Interconnection, released the second report in a series on studying the impacts of a changing resource mix.[4] As part of the study, PJM tested three different carbon-free generation portfolios against several sensitivities. The sensitivities included electrification of heating and transportation, the emergence of energy storage, increased interregional transmission capacity, and changes to the energy and ancillary services markets. The study's second phase found that short-duration energy storage can help provide operation flexibility but that transmission and other resources are necessary to meet the system's seasonal capacity and energy needs. The most important finding was that the accelerated decarbonization and high electrification scenario–a scenario with 70% carbon-free generation by 2035 and an additional 19 GW of electric vehicle (EV) load and 14 GW of heating demand–entirely shifts the seasonal resource adequacy risk to winter. PJM has historically been a summer peaking system, with 95% of its loss of load risk experienced in summer. Looking ahead, PJM now must plan for a future scenario with 80% of its resource adequacy risk in the winter due to a disproportionate impact on winter load growth compared to summer.

This report aims to understand the risks that the Western U.S.–and Colorado in particular–is exposed to due to a changing climate while also transitioning to increasing penetrations of variable renewable resources. This report concludes with a set of questions on which the Commission seeks stakeholder feedback. Responses to the questions in this report can help inform the Commission of the limitations of current resource adequacy planning and opportunities to reform planning practices and processes that align with the state's statutory decarbonization targets.

2. Introduction to Resource Adequacy

Electricity is generated by power plants, transmitted across great distances, distributed to individual customers, and consumed in real-time. The ability of a utility or regional planning entity to meet demand with supplied generation is a form of reliability known as resource adequacy. Resource adequacy takes up a long-term planning focus where modeling and studies are conducted years in advance to identify new resource procurement needs.

There is no standard resource adequacy methodology adopted by system planners, state regulators, or utilities in the Western Interconnection. Several organizations monitor resource adequacy in the west, including the WECC, but there are no binding requirements or interconnect-wide programs. Thus, each utility or planning area determines resource adequacy through their respective integrated resource plans. Utilities can then procure new resources to ensure the probability of unserved load does not exceed reliability criteria.

[3] Nick Schlag, Adrian Au, Karl Walter, Ruoshui Li, Roderick Go, Tristan Wallace, Lakshmi Alagappan, Arne Olson. (February 2022). *Resource Adequacy in the Desert Southwest*. Energy + Environmental Economics. https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

[4] PJM. (May 2022). *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid*. https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220517-annual/item-06---renewable-integration-study-ris-20---presentation.ashx

2.1. Loss of load probability and loss of load expectation

Resource adequacy of a local or regional planning area is the ability of the electricity system to meet future demand under various weather and operating conditions. Resource adequacy analysis involves stochastic methods with variable inputs, including temperature, future demand projections and load growth, and the availability of resources.[5] Multiple metrics measure the resource adequacy of a system. The loss of load probability, or LOLP, is the probability that the electricity demand will exceed the available electricity supply. By aggregating the hourly loss of load probabilities annually, planners can calculate the cumulative loss of load probability to estimate a system's loss of load expectation. Most power systems use a standard 1-day-in-10-years loss of load expectation (LOLE) assumption–or 0.1 day per year–which measures the number of days an outage can occur in a system.

Historically, power system planners have used LOLE to identify a system's required planning reserve margin. A planning reserve margin is an excess capacity beyond the peak demand necessary to maintain system reliability expressed as a percentage. The assumption is that an adequate capacity reserve margin during a system's peak demand period should ensure sufficient power capacity to meet demand during all other hours. The planning reserve margin metric is easily digestible for traditional power systems composed of predominantly dispatchable generation resources such as nuclear, coal, hydro, and natural gas. Therefore, the planning reserve margin is the metric communicated to decision-makers and other stakeholders to indicate sufficient resource adequacy. The static planning reserve margin as a resource adequacy metric is less useful in systems consisting of increasing amounts of variable renewable energy and energy-limited resources.

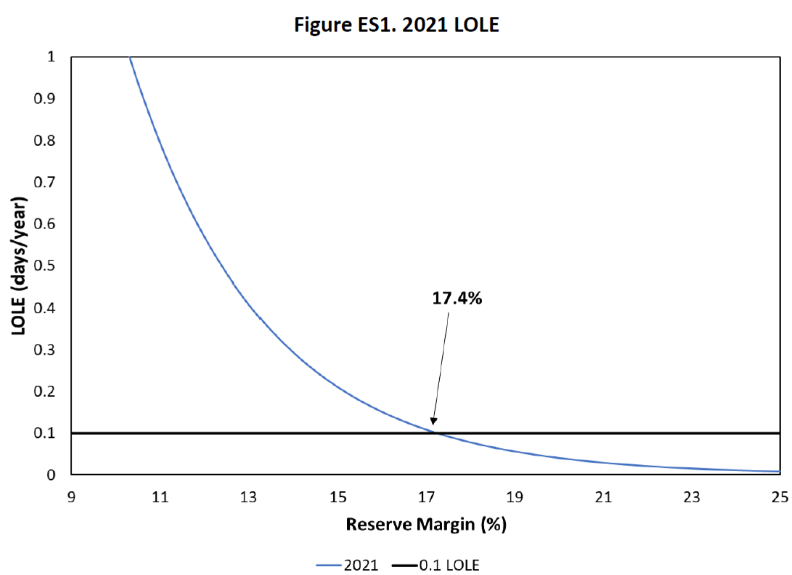


Figure 1. Public Service Company of Colorado Planning Reserve Margin Study from its 2021 Electric Resource Plan. (*Source: Public Service Company of Colorado*)

[5] J. W. Jagdmann, J. W. Betkoski, III, T. R. Mathews, A. Rendahl, M. Schuerger, T. J. Thomas, E. J. Nethercutt. (July 2021). *Resource Adequacy Primer For State Regulators*. National Association of Regulatory Utility Commissioners. https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042

2.2. History of the 0.1 LOLE reliability criteria

Where did the 1-day-in-10-years loss of load expectation metric come from, and why is it used today to determine planning reserve margins for electric utilities throughout the U.S.? In a 2013 white paper from Astrape Consulting titled "The Economic Ramifications of Resource Adequacy," the authors provide a concise history from their literature review.[6] In 1947, Giuseppe Calabrese published a paper on the "probability method" to determine the appropriate reserve capacity for a power system. He recommends quantifying reliability targets by the number of days of lost load over so many years, likely due to the low probability events that caused reliability shortfalls at the time. Another paper by a different author published in 1950 recognizes that the appropriate level of reliability is an average failure rate of one day in eight or ten years. Astrape Consulting discovered countless more papers that referenced the 1-day-in-10-years reliability criteria over the mid-century. In 1965, a blackout left 30 million people in the Northeast without power for hours. Following the outage, the Mid Atlantic Area Council (MAAC, now part of PJM) finally codified the 1-day-in-10-years rule of thumb. The mandate required all load-serving entities in its jurisdiction to plan sufficient generating capacity such that the probability of a loss of load event would not exceed one day in ten years.

2.3. Other resource adequacy metrics

LOLE is the most common reliability metric used to measure total system reliability. Other metrics used less frequently in resource adequacy analysis include loss of load hours (LOLH), expected unserved energy (EUE), loss of load events (LOLEv), and Effective Load Carrying Capability (ELCC).[7] LOLH is derived from LOLE to measure the duration of loss of load hours but should not be used interchangeably with LOLE. For example, a LOLE of 0.1 days per year equates to 2.4 hours. However, using the latter as a reliability target for planning purposes leads to different results; LOLE is generally more conservative than LOLH. The EUE metric measures the amount of energy in megawatt-hours that go unserved. LOLEv measures the number of events that occur per year. Lastly, the ELCC is the capacity contribution that a generation resource–or an entire resource portfolio mix–provides to the system to meet peak demand.

2.4. Traditional resource adequacy analysis and planning reserve margins

A system planning organization or a utility typically determines the planning reserve margin necessary to achieve a 0.1 LOLE using either the traditional analytical convolution method or chronological Monte Carlo simulations. The convolution method assumes independent random availability of resources and weather-driven variability in load. Traditional convolution methods do not consider the correlation between weather and generation resources nor run chronological operations to model the behavior of energy-limited resources such as energy storage. For example, convolution models frequently simulate the dispatch of storage resources in a way that does not accurately reflect real-time operations. The result is a less demanding modeling exercise that significantly undercounts the complex interactions between variable renewable resources, energy storage, and load.

---

[6] Carden, K. and Wintermantel, N. (January 2013). *The Economic Ramifications of Resource Adequacy White Paper*. Eastern Interconnection States Planning Council and the National Association of Regulatory Utility Commissioners. Astrape Consulting. https://pubs.naruc.org/pub.cfm?id=536DBE4A-2354-D714-5153-70FEAB9E1A87

[7] North American Electric Reliability Corporation. (July 2018). *Probabilistic Resource Adequacy Metrics Technical Reference Report*. https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

Conversely, Monte Carlo probabilistic methods determine the probability of unserved load at all hours of multiple forecasted years in chronological order. Monte Carlo simulations run various scenarios on load growth forecasts, weather and meteorological years, and generator forced outages at high temporal resolutions. Modeling each weather year sequentially, Monte Carlo differs from the Convolution method in that it acknowledges that the availability of a generator is dependent on its availability in the previous time step. However, Monte Carlo methods do not account for weather correlations in generator availability.

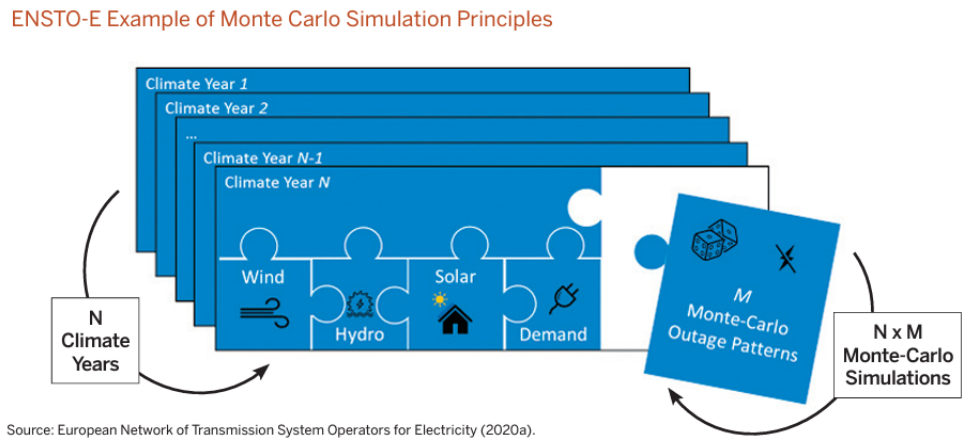


Figure 2. Monte Carlo simulations model N x M scenarios of weather and outage patterns. (*Source: Energy Systems Integration Group*)

The planning reserve margin informs how much additional capacity is needed in the future to meet demand reliably. Once the new capacity need is understood, a utility can decide which resources to procure to meet that demand using a capacity expansion model. Capacity expansion models forecast the least-cost portfolio of generation resources necessary to meet future demand. Inputs and assumptions include fuel prices, electricity demand, policy mandates, and technology costs.

The above metrics are singular values intended to portray a system's overall resource adequacy on average over a year. The expectation is that there will be a high consequence event that impacts the ability of the electricity system to meet demand with the available supply on 0.1 days per year. High consequence events historically constituted high-demand events in the winter or summer that coincided with forced outages of large thermal generators. Today, high-consequence events are occurring more frequently, and the types of events are also changing with climate change and increased penetration of renewables.

3. Climate Change and Extreme Weather Events' Impact on Resource Adequacy

One strength of the West is its diversity in climate, resource mix, and demand profiles that grid planners have taken advantage of through the design, planning, and operation of the transmission system over the years. Resource diversity includes hydropower in the Pacific Northwest, solar in California, and reservoir hydro, nuclear, and other baseload power in the Southwest. Of particular note is the diversity in climate and weather patterns that has promoted sharing resources through imports and exports via interstate transmission. Today, extreme weather events and general weather patterns are happening more frequently, lasting for more extended periods, and are more severe than in the past. Additionally, climate

change causes extreme weather to impact wider geographic areas, reducing the interconnection's ability to move power around to accommodate demand.[8]

3.1. Extreme weather necessitates a paradigm shift in resource adequacy planning

The weather has always been the most reliable predictor of daily and seasonal electricity demand. A hot summer day correlates with greater use of air conditioning in buildings and more generation capacity to meet the increased load. There are also seasonal and diurnal variations in electricity load profiles, with peaks and troughs in demand changing throughout the year. However, climate change and extreme weather events impact the ability of the system to maintain a balance of supply and demand. Excessive heat and heat waves directly increase air conditioning use during critical peak demand times on the grid in the late afternoon. Extreme weather events such as heat waves and winter storms are happening more often and are becoming more intense. These events increase heating and cooling demand, which can stress the power grid.

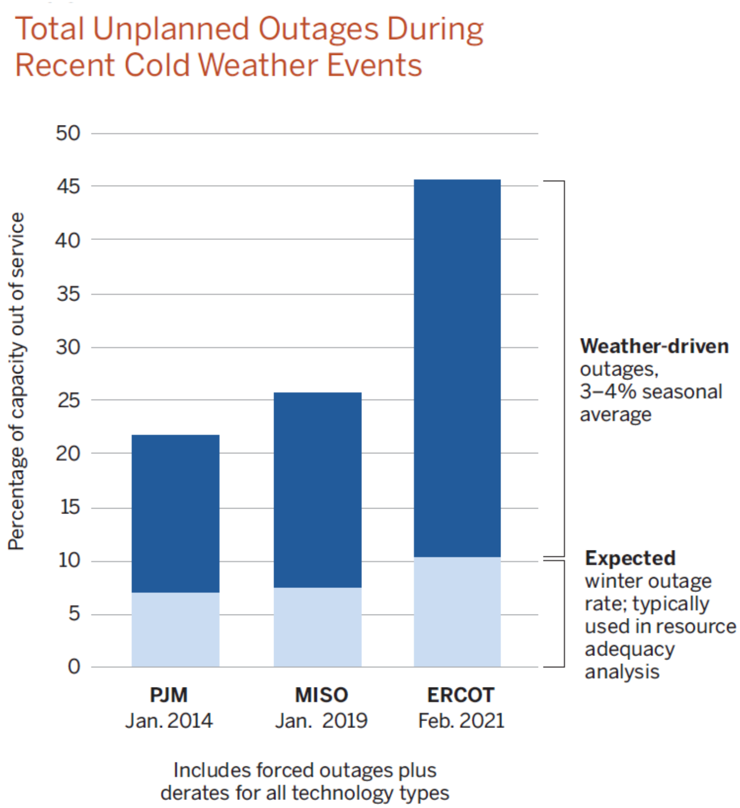


Figure 3. Weather-driven unplanned outages and derates for three different weather events in the PJM, MISO, and ERCOT planning regions. (*Source: Energy Systems Integration Group*)

Extreme weather events also impact thermal generation availability. Reduced availability of natural gas generators during extreme cold events is evident across the U.S. In three separate weather events across the PJM, MISO, and ERCOT service territories, cold weather-driven outages vastly exceeded the expected and planned winter outage rates. If forced outage rates

[8] Bradfield Lyon et al. 8 November 2019. *Projected increase in the spatial extent of contiguous US summer heat waves and associated attributes*. Environmental Research Letters Volume **14** Number 114029. https://iopscience.iop.org/article/10.1088/1748-9326/ab4b41

for thermal generators–especially natural gas–are not correctly accounted for upfront in resource planning and procurement, reliability and resource adequacy suffer.

This increased risk of extreme weather to the thermal fleet has materialized in two distinct ways. First, the retirement of coal power plants and investment in natural gas has reduced the diversity of fuel supply of the electricity generation resource mix. The result is a coupling of the electricity system with the natural gas delivery system, which increases the risk of correlated outages. The overreliance on natural gas as a fuel source in the electricity system increases the probability of correlated outages of the natural gas generation fleet due to supply failures caused by freezing temperatures and winter storms, as seen in Texas during Winter Storm Uri. Second, today's natural gas combined-cycle and combustion turbine power plants depend more on ambient temperatures than traditional steam turbines. In the summer, the available output capacity of natural gas power plants decreases during extreme heat events, which correlates natural gas resource availability to weather. In the winter, cold temperatures increase the likelihood that combustion turbines experience mechanical failures.

A changing resource mix and varying demand patterns also change when the grid experiences a risk of a capacity shortfall. However, resource adequacy methods have yet to adapt to evaluate the risk of shortfall events at times other than peak load periods. Current methods assume static loads and reliability events are uncorrelated and that unforced outages happen randomly. Traditional resource adequacy analysis assigned a 5-10% unforced outage rate to generators to account for mechanical and electrical failures. However, a fundamental assumption was that these unforced outage events occurred randomly and uncorrelated with other outage events that affected the availability of multiple generators. Today, a changing climate, increased weather variability, and the probability of extreme weather all increase the likelihood of combined outages that can affect numerous generators simultaneously.

For example, following Winter Storm Uri in February 2021, the Federal Energy Regulatory Commission released a report detailing generator outages' impacts and availability. The Commission found that freezing temperatures and extreme weather caused 86% of generator outages and power supply loss, impacting the entire natural gas supply chain from the wellhead to midstream processing facilities and the power plants.

Before Winter Storm Uri, researchers at Carnegie Mellon University had already created a statistical model that quantified the temperature-dependent forced outage rates for natural gas combined cycle and combustion turbine generators.[9] The team studied 1,845 generators in the PJM market over 23 years of correlated generation, load, and weather data. The results show that the temperature dependencies for natural gas generators are statistically significant for both low and high temperatures but are more severe for low temperatures. At low temperatures, combined cycle and combustion turbine gas generators in the PJM market saw their available capacity drop to 80% and 85% of installed capacity, respectively.

[9] Sinnott Murphy, Fallaw Sowell, Jay Apt. (2019). *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence*. Applied Energy. Volume 253. 113513. ISSN 0306-2619. https://doi.org/10.1016/j.apenergy.2019.113513

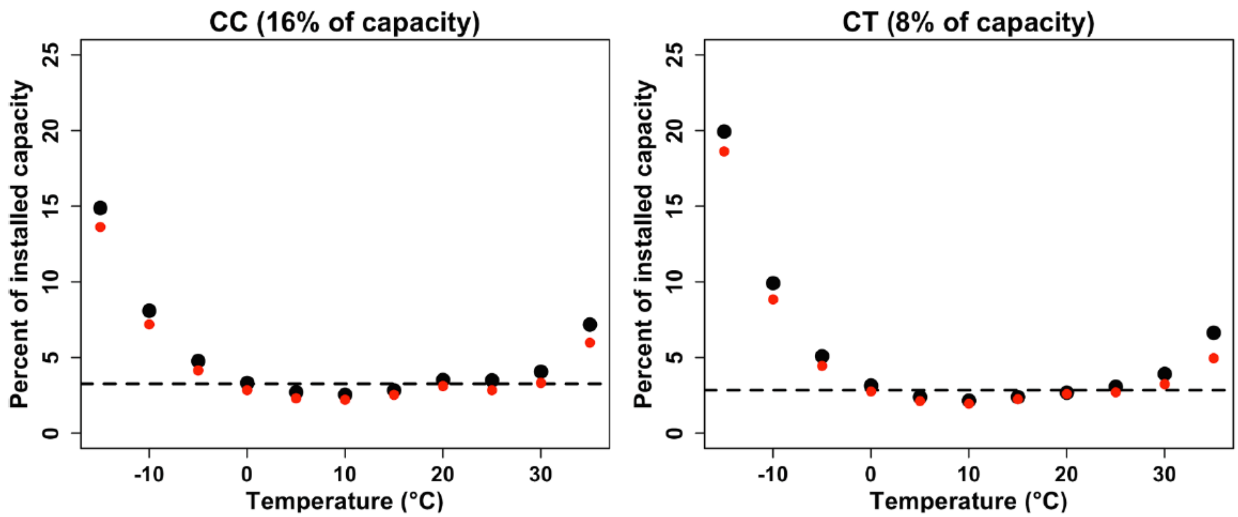


Figure 4. Temperature-dependent forced outage rates for natural gas combined cycle and combustion turbine generators in the PJM market using a statistical regression model. (*Source: Applied Energy, Carnegie Mellon University*)

Extreme heat also causes forced outage rates to deviate from average planning assumptions. Extreme heat and high temperatures decrease the density of the air, which directly reduces the efficiency of gas turbines—this decreased efficiency results in reduced power output. In PJM, ambient derates at high temperatures reduce the capacity of gas generators by approximately 5%, based on the statistical analysis performed by researchers at Carnegie Mellon University discussed above. Lastly, extreme heat coupled with extended drought can impact the available water supply necessary for thermal generators. The impacts of drought extend beyond the thermal fleet; in the West, hydropower availability is also at risk.

Hydropower constitutes between 20-25% of the generation capacity in the West.[10] Hydropower availability–including run-of-river and reservoir hydropower plants–is directly impacted by drought conditions and long-term climate trends. Persistent drought in the West limits the ability of reservoir hydroelectric and pumped storage hydropower resources to replenish water storage capacity. In drought conditions and over time due to climate change, the West is likely to experience increased frequency of low rainfall periods, low snowpack accumulations in the winter, and earlier snow melts which can combine to cause an earlier peak flow through hydropower facilities. As a result, hydropower plants will have fewer available reserves during the summer when the grid can experience increased stress due to the high demand for air conditioning. The loss of hydropower capacity has ramifications across the Western Interconnection due to its ability to provide flexible services by quickly ramping generation output to maintain a supply-demand balance.

3.2. Impact of historical weather events on the future grid

New research from the National Renewable Energy Lab confirms that extreme weather events will impact solar, wind, and thermal generation availability, necessitating updated planning

[10] Somani, A.; Datta, S.; Kincic, S.; Chalishazar, V; Vyakaranam, B.; Samaan, N.; Colotelo, A., Zhang, Y.; Koritarov, V; McJunkin, T.; Mosier, T.; Novacheck, J.; Emmanuel, M.; Schwarz, M.; Markel, L.; and O'Reilley, C. (August 2021). *Hydropower's Contributions to Grid Resilience*. U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-30554.pdf

strategies.[11] Overall, NREL found that high wind and solar penetrations do not inherently negatively impact system resource adequacy. The study revealed that wind and solar resources exhibited average seasonal availability during the extreme weather events due to strong correlations between extreme heat and sunny conditions in the summer and between extreme cold and high winds in the winter. There are exceptions to these generalizations, as well as uncertainty to the spatial and temporal extent of the impacts on solar and wind availability throughout extreme weather events. However, overall, high penetrations of wind and solar do not introduce new resource adequacy concerns or make planning more difficult during extreme weather events that historically introduced risk to the system due to high loads.

In the report, NREL categorized weather events into “High Impact Events” and “Events Posing Potential Challenges.” High Impact Events included cold waves, midlatitude storms, heat waves, and tropical storms. Events Posing Potential Challenges included low variable renewable energy resources with high demand and high variable renewable resources with low demand. The study included weather events that occurred between 2007 and 2013. NREL then used its ReEDS capacity expansion model to build future power grid scenarios for three test years: 2024, 2036, and 2050. NREL tested the projected infrastructure for the three years against the historic weather events from 2007-2013. Additional sensitivities included production cost modeling to test the reliability of future infrastructure against historical weather events.

Historically, electricity demand peaks in either the coldest winter mornings or the hottest summer days. For Colorado, hot days in July and August tend to present the most significant resource adequacy risk. Again, generally, NREL finds that wind and solar do not introduce new risks during these times. There are nuances to this finding. High solar penetrations push the net peak to later in the day and narrow the net peak, which shifts the dispatch of other resources such as hydro and natural gas later in the evening to meet net load. For wind, NREL finds that although wind generation is lowest in the summer months, high wind penetrations and the ability to move wind around via transmission provide an evening generation source as solar generation declines. Lastly, NREL found that extreme heat events did not lead to lower wind generation, but “moderate” heat events did result in decreased wind generation for the events in the dataset. “Based on the weather years of 2007–2013, the most pressing events for planners and operators to ensure sufficient capacity at the net load peak appear to be moderate heat waves accompanied by persistent high pressure and low wind generation.”

NREL also identified a new risk from a previously benign weather event: extended mild weather conditions. Sustained periods of low wind and solar generation caused by inclement weather conditions–cloud cover and low winds–pose a significant threat to resource adequacy at high penetrations of variable renewable energy. “...winter events tend to have more prolonged periods of poor wind and solar resource over larger areas, leading to extended periods (i.e., multiple days) of high net load.” Extended periods of low wind and solar resource availability are more likely to occur in the winter, where days with high net load do not typically coincide with winter and summer peaks. NREL recommends that system planners focus more on these events to ensure resource adequacy with increasing wind and solar penetrations.

[11] Josh Novacheck, Justin Sharp, Marty Schwarz, Paul Donohoo-Vallett, Zach Tzavelis, Grant Buster, and Michael Rossol. (2021). *The Evolving Role of Extreme Weather Events in the U.S. Power System with High Levels of Variable Renewable Energy*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-78394. https://www.nrel.gov/docs/fy22osti/78394.pdf

More research is needed to understand the climate and meteorological impacts on the future power system. The NREL study offers a starting point for future work, which could include weather events from forecasted climate models that capture the extreme scenarios and weather events the U.S. is likely to face in the coming decades. A heat wave or a winter storm in 2013 may underpredict the future exposure risk the power grid will likely face in 2035. Extreme weather events are becoming more severe and occurring at higher frequencies due to the continued burning of fossil fuels over the past decade. Historical datasets may not fully capture the resource adequacy and reliability impacts, while studying the effects of previous extreme weather events on future power systems with high renewable energy penetrations may be helpful. The weather will become an essential variable for long-term resource planning at higher penetrations of wind and solar.

3.3. Correlation of weather and electricity generation

Increasing penetrations of variable renewable energy resources like wind and solar strengthen the correlation between weather and electricity generation. Solar operates on a predictable diurnal pattern; in areas with high penetrations of solar–both utility-scale and behind-the-meter–as the solar production decreases with the setting sun, the net-peak load is shifted to later in the evening. Conversely, wind speeds are generally higher at night and lower during the day. Storm fronts can pass through regions that bring high winds and cloud cover, increasing instantaneous output from wind and decreasing production from solar. At high penetrations of wind and solar, weather patterns that reduce solar and wind availability can increase the risk of supply shortfall outside peak demand times.

Climate change and extreme weather elevate the importance of meteorological forecasting for wind and solar and the operational considerations for managing sudden changes in resource availability (i.e., wind ramps). Traditional resource adequacy planning relied on the predictability of fossil generation, and load and system reliability did not suffer. Using historical weather data to analyze future resource adequacy needs may not fully capture all of the risks, given the effect weather has on both system load and resource availability. For long-term resource adequacy planning, flexible resources, such as storage and demand response, and clean dispatchable generation, like geothermal and hydropower, will be required to manage demand variability.

The geographic diversity of renewable resource deployments can reduce the correlation with weather events.[12] Intrastate and interstate transmission development is the key to accessing the geographic diversity of renewable resources across utility service territories and regional transmission organizations. Yet, resource adequacy modeling is complex and transmission access is either ignored or capped in traditional resource adequacy planning as a conservative approach to ensuring sufficient resources within a planning area's service territory. This approach to transmission reduces efficiencies caused by geographic and temporal diversities in load and generation. For example, in Public Service Company of Colorado's 2021 Electric Resource Plan, the Company capped transmission imports from neighboring balancing authorities and did not include the entire WECC in its planning reserve margin study. The Commission, in Decision No. C22-0559, ordered the Company evaluate whether including the entire WECC and not capping imports provides a net-benefit to its planning reserve margin

[12] Isaac Bromley-Dulfano, Julian Florez, Michael T. Craig. (2021). *Reliability benefits of wide-area renewable energy planning across the Western United States*. Renewable Energy. Volume 179. Pages 1487-1499. ISSN 0960-1481. https://doi.org/10.1016/j.renene.2021.07.095

modeling methodology in the 2024 Pueblo Just Transition Solicitation.[13] If the Company decides not to include the changes to its modeling methodology then it must provide an explanation as to why it did or did not adopt it.

However, transmission infrastructure is not immune to climate change and extreme weather effects. Extended drought and heat waves, coupled with extreme wind events, can permanently damage transmission systems or put them temporarily out of service to prevent wildfires. Today, utilities and regulators are looking at alternative transmission siting approaches, including burying lines in high-risk areas and non-wires alternatives (NWA).

3.4. Energy storage, demand-side resources, and flexible generation

Incorporating weather forecasting and climate change in resource planning and procurement is paramount for power systems with more wind and solar. At the same time, increased generation and load flexibility and energy-limited resources on both the transmission and distribution grids can provide valuable resource adequacy benefits. First, utility planners must assess reliability considering the impacts of energy-limited resources in real-life chronological operations. For example, battery storage is an energy-limited resource that requires charging after dispatching energy. The availability of a battery storage resource at any given time depends on the weather and resource availability in both the preceding hours and days and proceeding hours and days. Yet, the modeled energy storage behavior in resource adequacy analysis is often not based on scheduling and dispatch models but on simplified deterministic analytical methods.

The same is true for demand response; the availability of a demand response resource depends on past usage and future needs. For example, a participating heat pump in a utility direct load control program cannot be turned off or reduced indefinitely, and the action is only beneficial during specific times. For resource planning, utility demand curves often account for average adoption rates of behind-the-meter resources (rooftop solar and stationary storage) across service territories. Distributed resources such as storage, solar, EVs, and electrified appliances in buildings are uniquely different, with unique load shapes and flexibility capabilities. They are also not considered as a flexible resource available to balance supply and demand.

Another benefit of distributed energy resources, demand response, and flexible load resources is that they are all interconnected across the distribution system in a modular fashion, reducing the correlation between weather and forced outages. The same concept applies to utility-scale inverter-based resources: as the penetration of solar, wind, and batteries increases, the modular design of these resources reduces the risk of complete loss of resource availability from a centralized power plant. Solar, wind, and utility-scale battery deployments consist of multiple independent power inverters in a modular design. A single point of failure to an inverter, solar panel, or wind turbine does not impact the entire plant.

Flexible operations on supply-side resources will also be crucial for systems with high penetrations of wind and solar. With the accelerated adoption of wind and solar through the rest of this decade, Public Service Company of Colorado is expected to provide 80% of its electricity generation from renewable resources. Natural gas generation is popular and

---

[13] Colorado Public Utilities Commission. September 21, 2022. *Commission Decision Addressing Applications For Rehearing, Reargument, Or Reconsideration Of Commission Decision No. C22-0459*. Proceeding No. 21A-0141E Public Service of Colorado - 2021 ERP and CEP.
https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=29398

successful today because, unlike coal and nuclear, natural gas combined cycle plants are good at ramping to complement solar and wind power swings. Wind and solar ramping plus rapid changes in demand suggest that power systems need carbon-free resources with high ramp rates to maintain a supply-demand balance.

Climate change and extreme weather will invariably impact current and future power systems, necessitating a paradigm shift in resource planning and procurement. There is sufficient evidence to suggest that wind and solar will dominate capacity deployment and power generation in the coming years. Planning must incorporate weather forecasting and flexible resources on both the supply and demand sides. Natural gas generation is not immune to the effects of climate change. Flexibility and diversity of resources and geography will be vital to providing resource adequacy in the coming years and decades. Given the risks of natural gas generation and the non-capacity value of flexible resources to pair with variable wind and solar, the following section critically examines the current capacity-based planning practices.

4. A Critical Look at Effective Load Carrying Capability for High Renewable Systems

Increasing penetrations of renewable and energy-limited resources add complexity to a system that utilities in the 20th century initially built with firm generation resources whose availability was largely independent of weather variability. Existing resource adequacy and capacity procurement frameworks must adapt to the changing resource mix. Today, system planners and resource adequacy analyses utilize the ELCC metric to assign discounted capacity accreditation to variable renewables and energy-limited resources.

The ELCC of an imperfect resource, which includes all resources, including thermal, renewable, and energy-limited resources, is measured as the capacity that a system can count on the resource to meet system demand and provide equivalent reliability to traditional firm resources. The ELCC methodology offers a workaround to integrate renewables without changing traditional planning processes that rely on capacity-based methods. To calculate the ELCC for an imperfect resource, system planners run stochastic models to estimate the system reliability with the new resource. Then, they incrementally replace the imperfect resource with a 100% dispatchable, always on, firm capacity (perfect) resource in the system to achieve the same reliability. The ELCC of the imperfect resource is the amount of firm capacity added to the system. For example, if a 75 MW perfect capacity resource can replace a 200 MW solar array, then the ELCC of the solar array is 75 MW.

4.1. Saturation effects of same-type resources

Calculating the ELCC of an individual imperfect resource is dependent on the underlying resource mix and demand patterns. Adding more variable renewable and energy-limited resources to the system highlights two critical effects. The first is the saturation effect: as more of a resource type is in the system–solar, wind, or battery storage–the resource type’s marginal ELCC decreases. Note that the saturation effect assumes that the underlying resource mix stays the same. Therefore, the marginal resource adequacy benefits decrease with increasing penetrations. The figure below represents this behavior for solar.

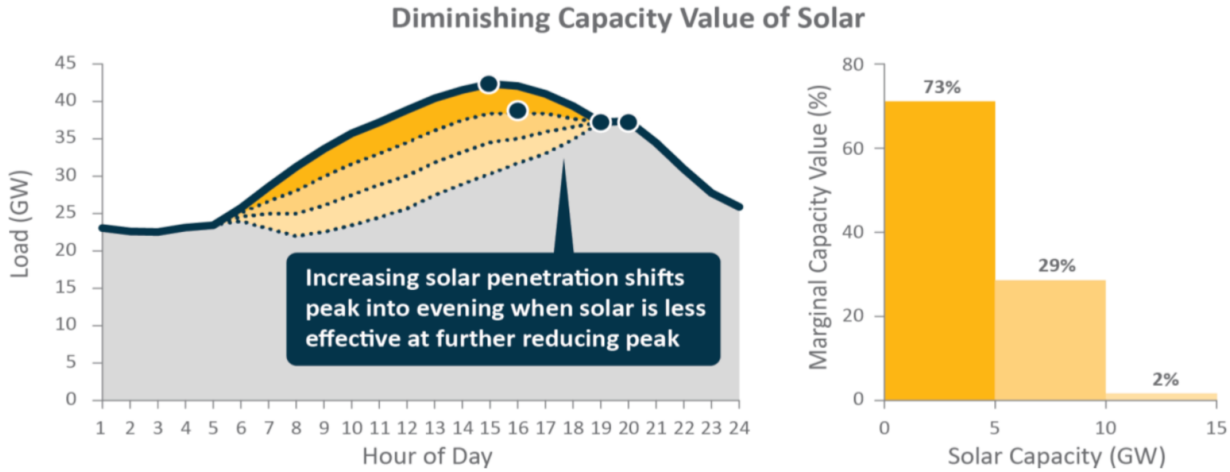


Figure 5. The marginal solar capacity value decreases with increasing penetrations of solar. (*Source: Energy + Environmental Economics*)

To further demonstrate the saturation effects of non-firm resources, the figure below shows the marginal capacity value of a 4-hour battery storage resource on the same system shown above for solar. If the resource mix remains the same, the capacity value of 4-hour duration storage decreases for each additional battery resource added due to the demand profile and the storage's finite duration. The penetration of 4-hour duration storage directly affects the peak demand period. Hence, adding more 4-hour storage resources to the system decreases the effective capacity value of the resource due to the need to provide energy over a longer duration.

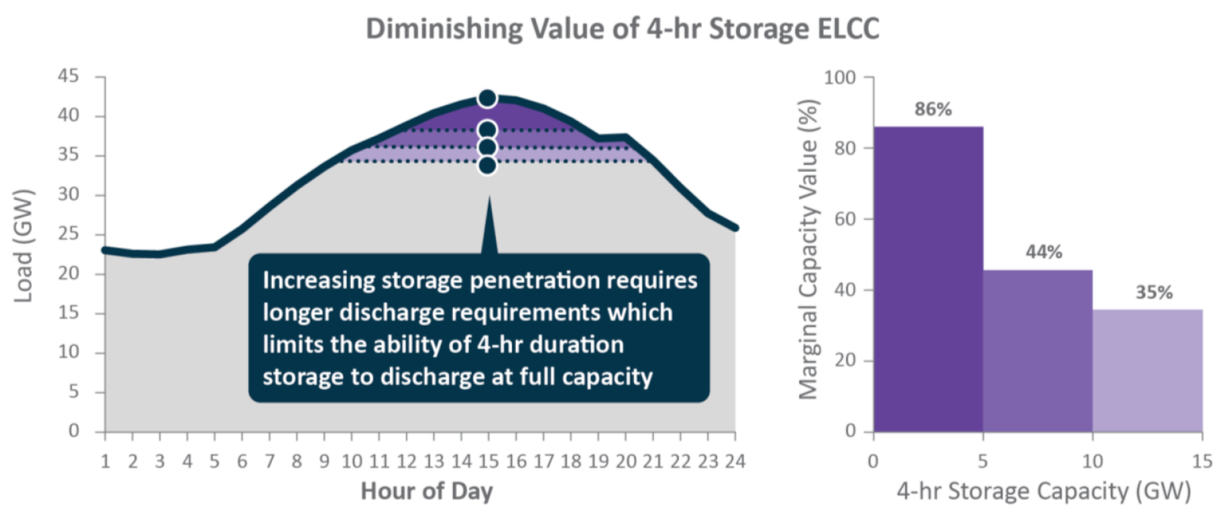


Figure 6. The diminishing capacity value of fixed-duration storage resources with more storage in the system. (*Source: Energy + Environmental Economics*)

4.2. Portfolio effects of complementary resources

The above figures show the saturation effects of solar and storage resources added independently to the same system. The capacity value of solar resources can change with

more diverse resources such as wind or storage. The portfolio effect is the second effect observed with increasing penetrations of variable renewable and energy-limited resources. Adding resources with complementary characteristics can provide more resource adequacy than the sum of the individual resources' ELCC values. Common resources that exhibit the diversity benefit include solar + wind and solar + storage. Each of the resources complements the other's shortfalls. The figure below shows how adding solar and storage together yields a diversity benefit with an overall capacity value more than the sum of the individual capacities.

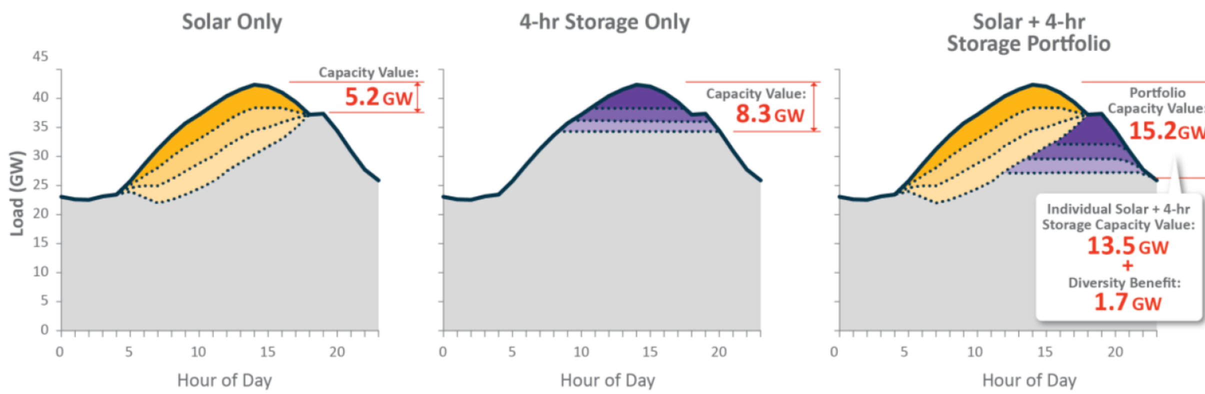


Figure 7. Portfolio effects of solar and storage (*Source: Energy + Environmental Economics*)

The marginal capacity decreases with more solar in the system in isolation. Another effect is observed: more solar shifts the peak demand to later in the day and shortens the peak demand period. Conversely, adding more 4-hour storage in isolation increases the duration of the peak demand period while decreasing the net demand. Finally, with solar and storage added to the system, the storage can move more energy to the net peak created by the solar. Solar and storage are a synergistic combination of resources that yields a net positive capacity benefit when added to the system. Other synergistic combinations include solar plus wind and a portfolio of solar, wind, and hydro.

Conversely, interactions between resources can also be antagonistic, where their pairing results in a net capacity value that is less than each of the individual capacities. Antagonistic pairings include different technologies of energy-limited resources such as hydropower, energy storage, and demand response.

4.3. Storage ELCC is a function of storage duration and renewable energy penetration

NREL's Storage Futures Study analyzed various storage technologies and determined their cost-competitiveness based on the types of grid services they can provide.[14] Researchers then integrated their assessment of storage technologies and capabilities into future outlooks for the power grid. The overarching finding from the multi-year study is that energy storage technologies exhibit a trend of increasing marginal cost and decreasing marginal benefit associated with increasing storage duration. For example, Li-ion battery technologies have a high energy cost (i.e., storage duration, measured in megawatt-hours) and a low power cost

[14] Denholm, Paul, Wesley Cole, A. Will Frazier, Kara Podkaminer, and Nate Blair. (2021). *The Four Phases of Storage Deployment: A Framework for the Expanding Role of Storage in the U.S. Power System*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77480. https://www.nrel.gov/docs/fy21osti/77480.pdf

(power capacity, measured in megawatts). Thus, the economic performance of Li-ion battery storage decreases with increasing duration. However, as the penetration of variable renewable energy resources increases, namely solar photovoltaic (PV), the net-load profile of local and regional grids will change.

Based on modeling scenarios, data and insights from historical deployments, and recent analyses and industry projections, NREL anticipates new storage deployments will follow a trend of increasing duration following the deployment of solar PV and solar + storage (hybrid) resources. Today, 2-6 hours of energy storage deployments can provide peaking capacity services, replacing natural gas combustion turbine peaking plants and other fossil combustion resources. The saturation effects of solar PV and storage will ultimately limit the deployment of 2-6 hours duration storage resources. Conversely, the portfolio effects of solar and 2-6-hour storage durations enable the deployment of 350% more storage capacity in systems with higher penetrations of solar PV.

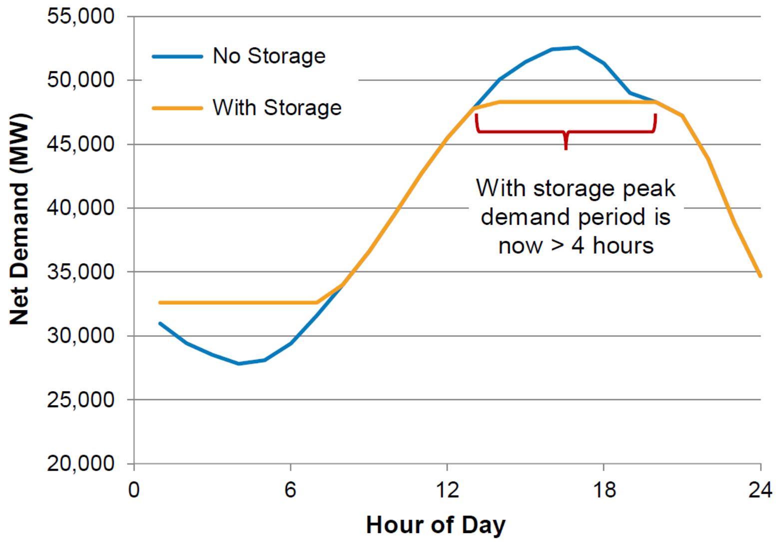


Figure 8. 4-hour storage deployments reduce peak demand but increase peak demand period. (*Source: National Renewable Energy Lab*)

Over time, the saturation of 2-6-hour energy storage resources reduces the net-load peak capacity and increases the net-load peak duration. As energy storage costs decline, technology improves, and solar penetration increases, energy storage resources that can provide long-duration storage for up to 12 hours become cost-competitive. NREL highlights this deployment stage where the industry might see new technologies become cost-competitive with the dominant Li-ion chemical battery technologies. New technologies include next-generation compressed air, thermal and mechanical-based storage technologies, and pumped storage hydropower. These storage technologies become cost competitive due to extended peak demand periods and lower marginal energy costs than Li-ion batteries.

Additionally, higher capacity diurnal storage unlocks new opportunities for time shifting as it can capture more of the curtailed energy from solar and wind. In addition to providing capacity value, long-duration diurnal storage can help defer transmission investments by reducing transmission congestion. Longer-duration storage deployments can increase the capacity of existing transmission infrastructure used to connect to remote variable renewable energy resources, particularly wind, due to its diurnal mismatch with demand. For Colorado, storage resources with higher capacity and longer durations can capture curtailed wind energy

from the Eastern Plains and better utilize existing transmission infrastructure in addition to providing peaking capacity and energy shifting services. Thus, the ELCC of storage resources is not static but is constantly changing with the resource mix. The storage value also extends beyond capacity, so ELCC provides only a partial piece in the resource adequacy value stack.

4.4. Case study: resource adequacy planning failed in the face of extreme heat

Following the blackouts in August 2020, Gridworks-an organization that facilitates collaboration amongst different stakeholder groups to advance efforts for decarbonization and clean energy adoption-hosted a series of conversations with resource adequacy experts in the industry to identify opportunities to improve resource adequacy planning in California.[15] In its 2021 report "Resource Adequacy: Reliability Through the Clean Energy Transition," Gridworks shared insights from its conversations with resource adequacy experts on the continued use of ELCC in resource adequacy analyses.

The diurnal net peak of the California power system has shifted to later in the evening due to the increasing penetration of solar and other clean energy resources. The presence of this net peak represents an anomaly. Although options exist to modify system processes to account for this change by planning for the net-peak load, the underlying issue remains. The times when the system experiences an increased risk of unserved load will continually change with a changing resource mix and will become increasingly variable and extreme with a changing climate.

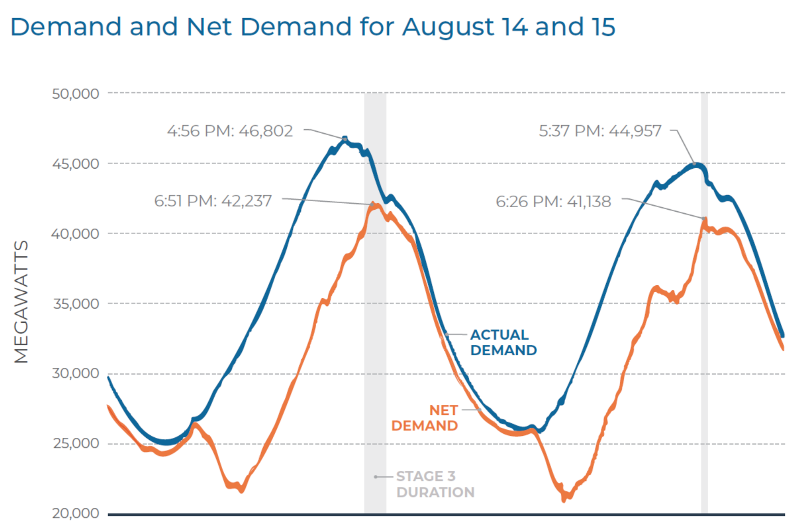


Figure 9. August 2020 rolling blackouts occurred after peak demand. (*Source: Gridworks*)

Through its conversations with industry experts, Gridworks found that many believe a new model is necessary to adapt resource adequacy planning to these changing conditions. Some experts suggested that systems should assess resource adequacy in terms of energy, not capacity. Instead of stacking resource ELCCs to meet sufficient planning reserve margins, a load-serving entity would procure resources for energy via a standard fixed-price forward contract. This finding was similar to the conclusions made by WECC in its 2021 Western Assessment. In another proposed approach, planning would still rely on capacity and ELCC, and procurement and performance monitoring done with actual energy produced. This

[15] Gridworks. (March 2021). *Resource Adequacy: Reliability Through the Clean Energy Transition.* https://gridworks.org/wp-content/uploads/2021/03/Resource_Adequacy_Reliability_through_Transition.pdf

performance-based approach could enable more competition and innovation, ensure a diverse resource mix, and meet a wide range of forecasted risks throughout the year. Key questions include how this approach would work in reality and whether the planning, procurement, and performance steps would need to be done in an iterative process to address the probable outcomes of lost load risk with the procured resources at all hours of the year.

Fundamentally, "capacity" is a regulatory product; regulatory entities require a sufficient capacity to ensure resource adequacy, which is bought and sold in markets. However, it is not the product delivered to customers; energy is the actual commodity. The ELCC methodology for accrediting capacity to non-firm resources can be a helpful tool for regulators and system operators to assess the ability of a system's resource mix to provide sufficient capacity. The ELCC of a resource is dependent not only on the demand profile but also on the existing resource mix. Similar resources offer diminishing value, and diverse resources create synergistic effects on the overall system where the marginal value exceeds its value. Therefore, the reliability of an individual resource is relative, not absolute, and calculating the ELCC value of a single resource among a system of renewable and energy-limited resources is complex. ELCC is better suited as a portfolio characterization, not of individual resources or specific resource types.

5. Recommendations from Industry Research, Peer-Reviewed Literature, and Modeling Studies to Adapt Resource Adequacy Planning

Resource adequacy planning needs to change drastically to address the shortcomings of existing analyses, processes, and methodologies. Resource adequacy must also become technology-neutral so that planning methods do not need to be adapted each time the power system experiences a paradigm shift in its operations. Colorado's power system must be able to adapt to a changing resource mix and the integration of new technologies needed to meet mandated carbon reduction statutes. Given the inefficiencies in the current resource planning process, this section summarizes industry research, peer-reviewed literature, and modeling studies that look to improve current planning processes.

5.1. Providing more insight into the characteristics of capacity shortfalls beyond LOLE

According to a November 2021 report by Grid Strategies, LLC, resource adequacy planning and resource procurement for systems with high penetrations of renewables, energy-limited resources, and load flexibility require a higher data resolution of the size, frequency, duration, and timing of shortfall events.[16] Current averaged resource adequacy metrics do not provide sufficient granularity into all of the possible types of shortfall events that could occur. The report continues to suggest that instead of relying on static average metrics such as loss of load expectation, loss of load hours, or expected unserved energy, utilities and system planners will need access to more granular metrics that fully characterize all of the expected shortfall events to make the necessary resource procurement decisions. For example, a system with frequent short-duration or low-capacity impact events could have the same average metrics as a system with rare long-duration or high-capacity impact events. The figure below highlights how expected average resource adequacy metrics don't fully characterize capacity shortfall events.

---

[16] R. Gramlich. (November 2021). *Ensuring Low-Cost Reliability: Resource Adequacy Recommendations for a Clean Energy Grid*. Grid Strategies, LLC and American Council on Renewable Energy. https://acore.org/resource-adequacy-report/

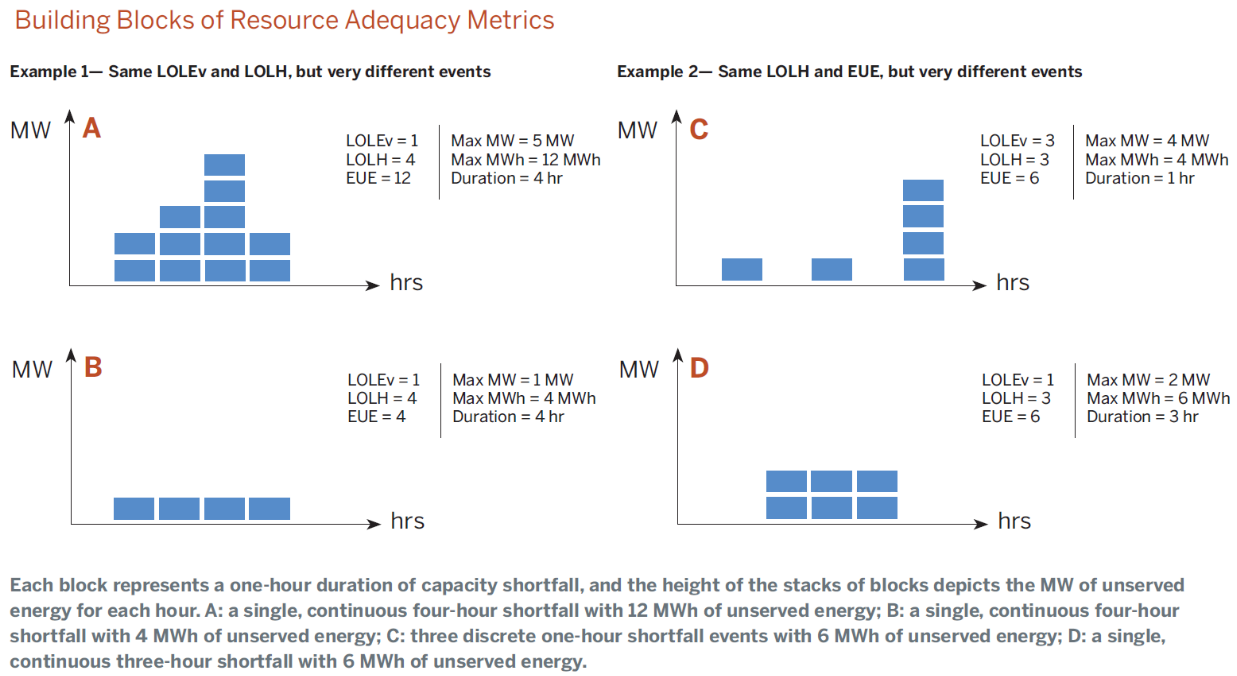


Figure 10. Planning processes must assess resource adequacy metrics holistically to get the complete picture. (*Source: Energy Systems Integration Group*)

Similarly, an average planning reserve margin also does not provide enough information to inform shortfall events' size, frequency, duration, or timing. Can future modeling analysis incorporate the above resource adequacy metrics to fully characterize the capacity shortfall events and identify resources that provide the necessary grid services? The below industry-proposed alternative approaches offer a means to improve current processes while also maintaining the existing planning framework centered around capacity and a planning reserve margin:

- One proposal recommends comparing the most economically efficient capacity reserves based on the costs and benefits of maintaining specific reliability criteria. At the most basic level, this would require an analysis that shows LOLE as a function of marginal investments necessary to meet reliability criteria and allow for a critique of existing arbitrary planning reserve margins.[17] Incorporating an economic analysis could better inform a more rational reliability metric based on the cost to meet varying planning reserve margins. This analysis would also include a value of lost load (VoLL) metric for transparency.

- Another proposal from a California Public Utilities Commission proceeding on resource adequacy suggests moving from a static planning reserve margin to seasonal planning reserve margins to account for the seasonal variability of variable renewable energy resources and correlated outages with thermal generation resources.[18] The year can be

---

[17] Schröder, T. and Kuckshinrichs, W. (2015). *Value of lost load: An efficient economic indicator for power supply security? A literature review*. Frontiers in Energy Research, 3(55), DOI: 10.3389/fenrg.2015.00055 https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full

[18] California Public Utilities Commission. July 16, 2021. *D2107014 Track 3B.2 Issues Decision*. Proceeding: R1911009. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF

divided into more resolute periods such as months, weeks, days, and times of day to account for multiple peaks and the physical behavior of energy-limited resources. Resources would count towards the capacity and energy for each period based on their probabilistic availability. The modeling analysis would ideally incorporate energy storage charging requirements to show the need to charge diurnal, long-duration, and seasonal storage.

- An alternative approach proposed in the California resource adequacy proceeding would incorporate the energy and capacity requirements described above that uses net load instead of gross load at a similar frequency. This approach uses a seasonal or monthly net load duration curve where a resource mix must meet both the peak net load and the total energy requirements for the specified period with available resources.

- Lastly, another proposed alternative approach splits the year into 8,760 individual-hour segments. There would be an hourly capacity requirement for each hour, and resources are assigned a capacity credit based on their statistical probability of delivering energy during that hour.

A planning reserve margin applied only to the summer peak load has been shown to ignore new risks introduced to the system in a changing climate and resource mix. To address this deficiency, the proposals above incorporate economic metrics and offer an alternative to the static planning reserve margin with variable reserve margins throughout the year.

5.2. Analyzing resource adequacy with chronological operations modeled across multiple weather years

A recent white paper published in NRRI Insights from modelers at Ascend Analytics has proposed new ways that existing resource adequacy analyses can adapt to high penetrations of renewable energy, high electrification and demand flexibility, and a changing climate.[19] A chronological probabilistic analysis models a system's resource dispatch for an entire year at an hourly resolution across many different weather years. Weather patterns could deviate from historical averages, and extreme weather events will likely increase in magnitude and frequency. Thus, to account for all weather-related risks and system vulnerabilities, system planners would ideally evaluate a system's resource adequacy risk across various climate scenarios and weather patterns. Historical meteorological conditions and datasets are incomplete in a rapidly changing climate. It may not be appropriate for utilities and regulators to rely on these historical datasets to predict future resource adequacy risk; alternatively, new datasets could be adapted to include anticipated events that have not happened in the past. Given that weather is the primary determinant for most other variables, benchmarking resource adequacy models with historical data is still essential to ensure models can predict future performance. At the same time, modelers may be better off using expanded weather datasets to cover a broader range of temperature outcomes.

[19] Mauch, B.; Millar, D; and Dorris, G. (June 2022). *Resource Adequacy Modeling for a High Renewable Future*. NRRI Insights. https://pubs.naruc.org/pub/DC366C78-1866-DAAC-99FB-4C0759DB57C5

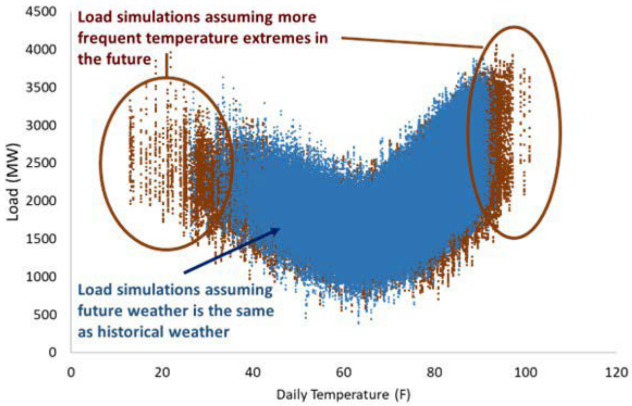


Figure 11. Climate change will increase the likelihood of extreme weather events such as heat waves and winter storms bringing in previously unobserved temperatures. (*Source: NRRI Insights, Ascend Analytics*)

As the authors of the NRRI Insights paper explain, current methodologies use average load and resource availability profiles or rely on randomized sampling from the variables' probability distribution functions. The NRRI paper continues to describe how this approach will not work with high penetrations of variable renewable generation, energy-limited resources, and fast ramping net load curves as they ignore real-world physics and chronological correlations. A better approach going forward will likely rely more on weather and climate forecasting. The underlying requirements for future systems with high penetrations of renewable energy and energy-limited resources are meteorological forecasting and resource scheduling. Increasing penetrations of renewable and energy-limited resources will shift periods of shortfall risk to other times of day and year. Concurrent weather and load data can help reveal the complex interactions between resource availability and electricity demand. A chronological evaluation of a system's resource adequacy is required to identify the precise times of risk of shortfall events; periods of risk are no longer limited to peak demand periods in the summer.

Resource adequacy planning underpinned by a static planning reserve margin based on the periods of highest gross demand may fail to capture the specific interactions of resources and load in a changing climate. For example, energy storage has limited energy to provide to the system, and it needs to recharge before the next event. The sequence of events is critical to understanding the value of energy storage or any other energy-limited resource, such as demand response. Energy-limited resources require either period of low demand or high resource availability immediately before or after discharging to provide adequate reliability. Modeling resource variability of renewable energy will identify periods where energy-limited resources are needed. By modeling power systems with chronological operations across multiple weather years, utilities, regulators, and other system planners benefit from a more robust and rigorous analysis that can manage high penetrations of variable renewables and energy-limited resources. As a result, stakeholders will also have more confidence that the new system will remain resilient to climate change and extreme weather impacts.

5.3. Applying ELCC to all resource types

The purpose of chronological stochastic modeling of system resource adequacy is to identify periods of risk throughout the year and to identify resources that can mitigate risks in different situations. Future power systems will require diverse resources on the demand and supply sides to remain resilient to different types of capacity shortfall events. For example, battery storage and load flexibility can address frequent short-duration events, but demand response might better serve the system for less frequent events. Neither of these resources is

available 100% of the time, but that does not mean they cannot provide valuable services to the grid in specific situations.

Conversely, natural gas combustion turbines may not be fit for purpose to be relied on to fill all resource adequacy gaps, as they are not a firm resource immune to unplanned events and severe weather. Power systems have historically modeled thermal generator outages as random with a constant forced-outage probability across time. In the future, thermal generators, especially natural gas combined cycle and combustion turbine generators, are best suited to be modeled as weather-driven with forced outage correlations to the temperature that includes common mode failures for natural gas production and distribution facilities.

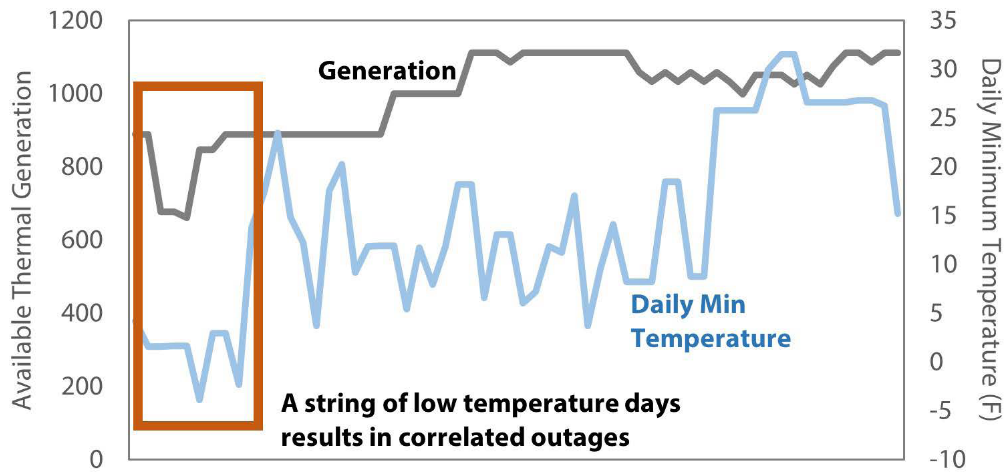


Figure 12. Resource availability modeling shows correlations to temperature. (*Source: NRRI Insights, Ascend Analytics*)

Current resource adequacy planning analysis is starting to rely on the ELCC metric to estimate the increased demand a resource can reasonably supply. Today, many natural gas combustion turbines get assigned a full capacity credit in ELCC analyses. Assigning 100% capacity credit to gas turbines assumes they can and should be dispatched at all times of the year to maintain the supply-demand balance. Accrediting natural gas with its total nameplate capacity also assumes they are immune to correlated weather events that impact the natural gas supply system. This practice ignores that natural gas generators are prone to extreme-high temperature derates and experience increased forced outage rates at extreme-low temperatures, as the researchers from Carnegie Mellon University demonstrated.

Assigning ELCC values to individual resources is non-trivial because ELCC is highly dependent on a system's load profile and resource mix. Demand and resource availability varies with the weather, so ELCC also relies on the accuracy of meteorological forecasting. For example, whether models dispatch energy storage resources to maximize resource adequacy or revenue–sometimes competing priorities–determines their value. Resource adequacy planning must account for the increased dependence that weather has on resource availability for all resources in a system, including fossil generators and energy storage resources.

5.4. Rethinking the capacity contributions of dispatchable natural gas generators

Most utilities and system planners today look to natural gas as a flexible dispatchable resource to meet resource adequacy and reliability needs as the resource mix changes. At the same time, utilities heavily scrutinize the reliability benefits of variable renewable energy and energy-limited resources. Today, new probabilistic methods such as ELCC apply to only these resources and not conventional thermal generating resources. Advanced Energy Economy (AEE), a national trade association representing the national clean energy industry, recently commissioned a paper by Astrapé Consulting highlighting these reliability concerns and market fairness.[20] In the report, Astrapé discovered that not critically analyzing the availability of thermal generators in a power system can lead to over-procurement of these resources and result in under-procurement of renewables and other clean energy resources. Astrapé discovered that the cost of the unaccounted risk shifts to customers. The consequences of this biased approach are an inefficient economic outcome (externalities and misappropriated costs) and a system with hidden reliability risks that pose a significant threat to resource adequacy.

AEE also asked Astrapé Consulting to assess current industry methodologies to accredit resource adequacy value to thermal resources.[21] They found that existing capacity accreditation methodologies overstate the capacity value of thermal resources by up to 20% in winter and 10% in summer by not considering the correlation between thermal availability and weather. Overall, Astrapé concluded that not accurately accounting for all potential risks can lead to underperformance of reliability, increased costs, and a delay in progress to carbon-free resources.

Today, thermal generators are assigned a capacity value based on their equivalent forced outage rate or their installed nameplate capacity. The assumption that their performance is uncorrelated with other outages, such as extreme weather, common-mode failures, and the availability of fuel, is no longer valid. Historically, power systems comprising predominantly coal, nuclear, and hydropower generation compensated for any risks to the natural gas fleet by over-building generation capacity. By assuming outages for thermal generators are independent, current resource adequacy analysis methodologies understate the resource availability risks in the capacity procurement and accreditation processes. AEE concludes that consequently, the demand side bears the capacity shortfall risk; the costs of poor reliability are shifted from the generators to the customers, thus removing the incentives to address the reliability concerns. If resource adequacy analysis moved the risk back to the thermal generators, it would decrease the capacity procurement value by the system and reallocate savings for other services to provide reliability benefits, such as transmission, demand response, flexible loads, and energy storage.

Suppose the risks of natural gas generators get passed through to capacity accreditation and resource procurement. In that case, AEE states, these resources may not compete economically with clean energy portfolios that can provide the same capacity, energy, and other grid services. As long as current practices remain in effect–misallocating the full benefits and costs of generation technologies–there is a risk of inefficient resource

[20] Advanced Energy Economy. (March 2022). *Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources*. https://www.aee.net/aee-reports/getting-capacity-right-how-current-methods-overvalue-conventional-power-sources

[21] J. Dison, A. Dombrowsky, and K. Carden. (March 2022). *Accrediting Resource Adequacy Value to Thermal Generation*. Astrapé Consulting. https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf

procurement during resource planning. The consequence of overreliance on natural gas generation is that the fleet may not be available when the system is most heavily dependent on it, as was most recently observed during winter storm Uri in 2021.

5.5. Redesigning capacity contribution methods for resource procurement and valuation

The examples above very neatly depict the diversity benefit between solar, wind, and storage. However, in existing power systems, many synergistic and antagonistic/saturation effects are occurring, making assigning individual capacity values increasingly tricky. Researchers and economists at E3 argue that there is not a single value that can capture the value added of a resource to a system in terms of capacity and resource adequacy.[22] E3 recently proposed an alternative framework for which it argues that there is not a single ELCC value that can capture the net benefit of a resource to a system in terms of capacity and resource adequacy. To more discreetly assign ELCC in systems with high penetrations of non-firm resources, E3 defined both a portfolio ELCC and a marginal ELCC. The portfolio ELCC is the combined capacity contribution of a portfolio of variable renewables and energy-limited resources that captures all the interactive effects–synergistic and antagonistic–amongst the resources. Then, the marginal ELCC is the incremental capacity contribution of a single resource or portfolio of resources added to a system.

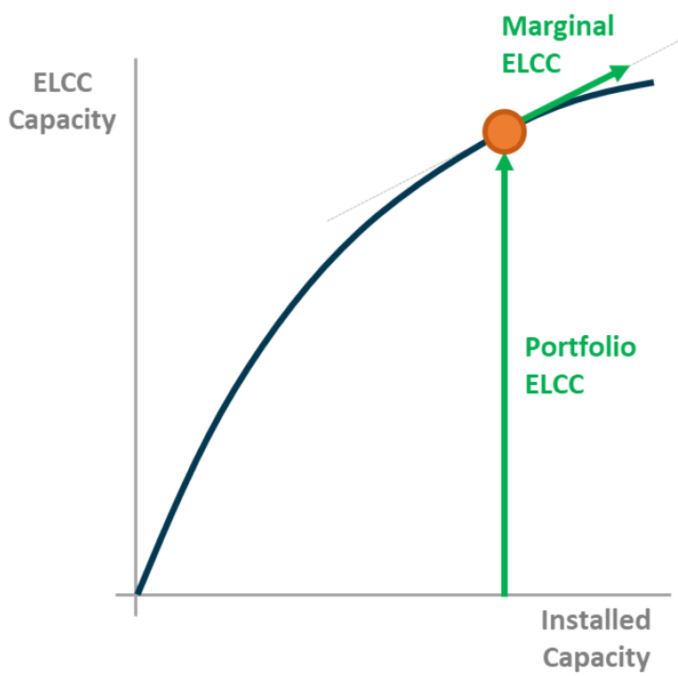


Figure 14. Visual representation of the portfolio ELCC and marginal ELCC of the "next" resource added to a system. (*Source: Energy + Environmental Economics*)

Although these concepts are relevant for systems with high penetrations of non-firm resources, the ELCC methodologies presented would ideally apply to all resources in a system, including fossil generators. Fossil generators do not show the same interactive effects as non-firm resources. However, applying the same stochastic ELCC modeling methodologies to non-firm resources promotes fair competition.

[22] N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang. (August 2020). *Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy*. Energy and Environmental Economics, Inc. https://www.ethree.com/elcc-resource-adequacy/

The frameworks presented above for ELCC apply to vertically integrated utilities and centralized resource adequacy programs. In the former, the utility is responsible for ensuring resource adequacy and should only be concerned with the entire portfolio's performance, not the individual resources. Therefore, a vertically integrated utility can analyze its entire portfolio for resource adequacy to calculate a portfolio ELCC. The utility can then use the marginal ELCC for individual resources to perform an economic analysis to find the best resource or mix of resources to add to the system.

Colorado utilities are required to join an organized wholesale market by 2030 per SB 21-072. In the context of a resource adequacy program within an organized market, the system operator assigns an ELCC value to individual resources. Organized markets use various schemes to assign individual resource ELCC values, such as applying a marginal ELCC value to all resources or applying average resource ELCC values to individual resources. Both methods face difficulty balancing system reliability, fairness to all technologies, market efficiency, and stakeholder acceptability. A significant challenge for existing schemes that apply ELCC to individual resources in capacity markets is the growing diversity of resources and configurations of hybrid resources. E3 highlights that resource classification and definition challenges will lead to inefficient outcomes for specific resources. It will become increasingly difficult to align a resource's assigned capacity accreditation with the underlying interaction effects of other system resources.

To overcome the issues with existing ELCC frameworks in capacity markets, E3 proposes their Delta Method, which utilizes existing ELCC measurements; portfolio ELCC, the first-in ELCC of a resource, and the last-in ELCC of a resource. The first-in ELCC of a resource is the marginal ELCC of a resource in a hypothetical system with no variable renewables or energy-limited resources. The last-in ELCC of a resource is the marginal ELCC of a resource added to the existing system resource portfolio. The first-in ELCC of a resource and the last-in ELCC of a resource inherently capture the interactive effects of a resource type in a system. In the proposed Delta Method, the last-in ELCC of a resource is adjusted up or down based on its contribution to resource adequacy such that the sum of all resource ELCCs added into a portfolio equals the portfolio ELCC. Applied in this way, the Delta Method is technology neutral and assigns ELCC values that represent the resource's value in the context of the system portfolio.

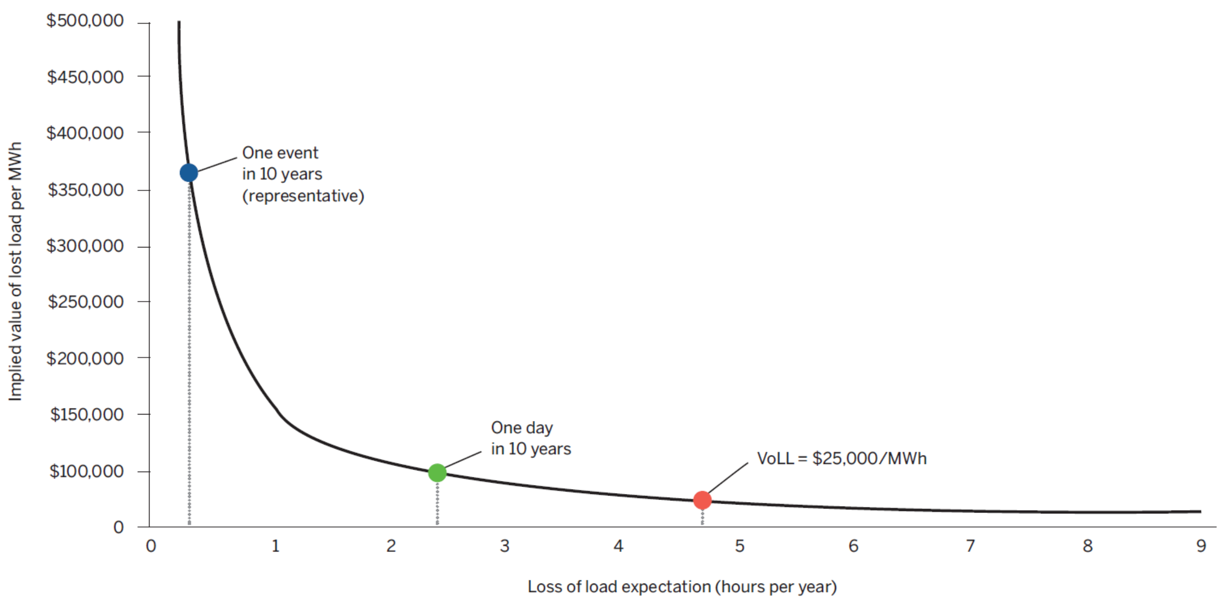
E3 offers some practical considerations before implementing the Delta Method in existing markets. First, the Delta Method requires significant modeling complexity and computational effort. Administratively, this can increase the complexity of operating power markets. Second, given that the ELCC of individual resources depends on the underlying resource mix, the ELCC of a resource may change over time, requiring additional market rules to consider how capacity accreditation and compensation will vary. E3's proposed approaches to competitive and fair capacity valuation offer an exciting starting point for Western power markets.

5.6. Including economic cost-benefit analyses in resource adequacy reliability criteria

Resource adequacy analysis directly leads to the procurement of new resources to maintain system reliability. The biases present in current ELCC studies and capacity accreditation, along with the lack of transparency into the costs of alternative resources such as transmission and demand-side resources, create economic inefficiencies in achieving reliability standards. The Energy Systems Integration Group's most recent report, "Redefining

Resource Adequacy," calls on the industry to rethink its resource adequacy planning and capacity accreditation methods.[23] The authors of the report argue that the analytical tools developed in the previous century to assess resource adequacy for power systems are no longer valid for the grid of the 21st century. There is an opportunity to increase the transparency of the costs required to achieve varying levels of system reliability so that policymakers and regulators can decide where to invest in overall system reliability. The below chart shows how it is economically impossible to achieve perfect reliability and where the PJM system's maximum estimated value of lost load (VoLL) of $25,000 based on previous studies compares with the current 0.1 LOLE reliability criteria.[24]

Comparing the Cost with the Value of Adding Resources for Reliability



Source: Regulatory Assistance Project / Hogan and Littell (2020).

Figure 15. Cost to add a new natural gas-fired generation resource in the PJM RTO under different LOLE reliability criteria. (*Source: Regulatory Assistance Project*)

At the same time, the VoLL is subjective. Prior studies have reached different conclusions when applying various methods to estimate the value of the unserved load. Past studies have employed many techniques to quantify the VoLL, including by proxy, surveys, and revealed preference. In a recent paper published in The Electricity Journal out of the University of California, Berkeley, the author concludes that the distribution of the costs of power outages vary across customer classes and different types of electricity consumers (residential versus commercial or industrial, for example).[25] This uncertainty also presents limitations in applying

[23] 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
[24] Hogan, M., and D. Littell. (June 2020). *Get What You Need: Reclaiming Consumer-Centric Resource Adequacy*. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2020/06/rap-hogan-littell-consumer-centric-resource-adequacy-2020-june.pdf
[25] Will Gorman. *The quest to quantify the value of lost load: A critical review of the economics of power outages*. The Electricity Journal. Volume 35, Issue 8. 2022. 107187. SSN 1040-6190. https://doi.org/10.1016/j.tej.2022.107187

VoLL in practice related to equity, given that lower-income and disproportionately impacted communities may be less willing to pay more for reliability given their income limitations.

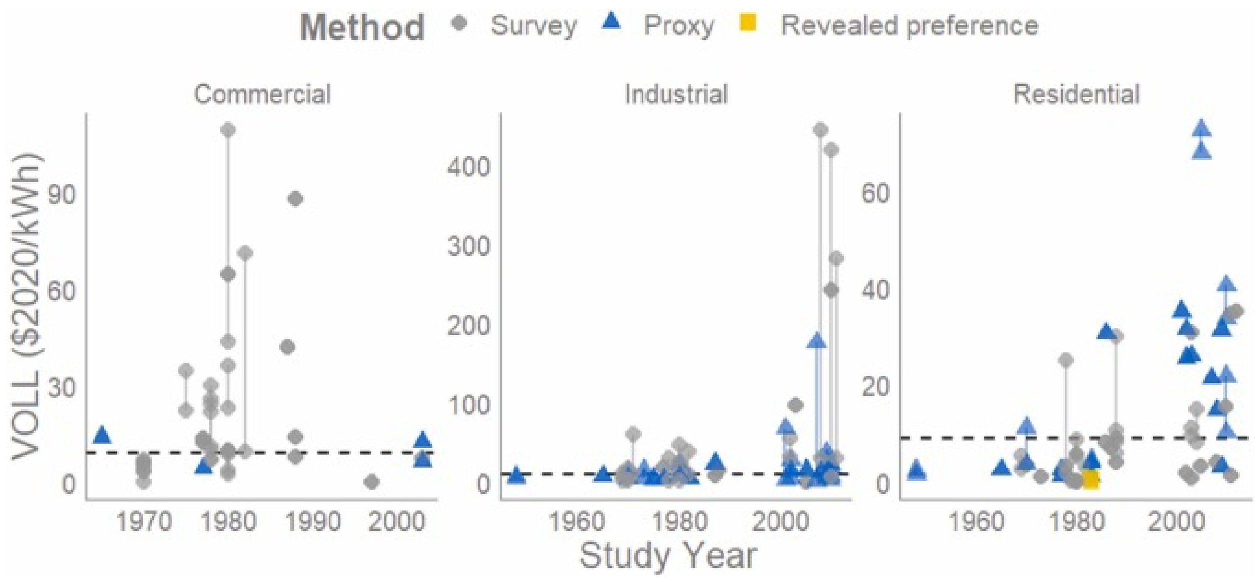


Figure 16. Estimates of the value of lost load over time. (*Source: University of California, Berkeley*)

Resource adequacy is a forward-looking planning process that aims to ensure a balance of supply and demand in the future. However, resource adequacy is not the only planning mechanism for or indicator of overall system reliability; most reliability events resulting in consumer power outages occur on the distribution grid. Resource adequacy does not consider ancillary or other grid services on the sub-second, second, minute, or hourly time scale. Applying VoLL using cost-benefit analyses is complex and represents a significant change from today's cost-effective approach using LOLP. Ultimately, resource adequacy solely focused on meeting non-economic reliability requirements may increase the probability that systems over procure capacity.

5.7. Prioritizing demand-side resources in resource adequacy planning and procurement

Load growth forecasts predict that future electricity demand will increase with the adoption of electric vehicles and the electrification of heating and cooling, among other factors. Instead of generalized load growth forecasts for an entire service territory or region, each of the primary drivers of future load growth could be analyzed and modeled individually, given their unique impact on the growth and shape of the demand curve profile. Electric vehicle charging may have different power and energy draws and other times of the day and stay consistent across seasons. In contrast, electrification of heating via heat pumps may disproportionately shift more load to the early mornings in the winter months.

Demand-side resources such as energy storage, demand response, and electric vehicles offer increased flexibility that can provide resource adequacy benefits to the power system. Flexible resources interconnected to the distribution system have decreased in cost and increased adoption. In addition to behind-the-meter solar and distributed energy resources in buildings, the transportation sector can provide valuable resource adequacy benefits through integration with the grid. Transportation electrification will place millions of mobile battery

energy storage resources in Colorado that will potentially integrate with the grid. Connecting vehicles with the grid through vehicle-to-grid technologies enables the grid to utilize the stored energy in the battery for energy, capacity, and ancillary services when not in use. Vehicle-to-grid applies to personal residential vehicles and large municipal and private fleets. For school buses and other vehicle fleets with favorable duty cycles, the ability to perform vehicle-to-grid does not limit a fleet's ability to perform everyday transportation and mobility services.

To better integrate demand-side planning with resource adequacy and resource planning, utilities, regulators, and system planners could consider demand-side resources and load flexibility as capable supply-side resources. Increased focus on resources interconnected to the distribution system, combined with more incentives for utility investment, could change the perception of demand-side resources. Particularly in resource planning and procurement, demand-side resources could be procured as supply-side resources as long as they meet the utility's and the regulator's requirements. Through this proposed process, utilities would survey and create an inventory of the resources in their service territory, including their availability across hours, days, and seasons and their energy limitations. These resources could provide the most significant benefit for systems that see infrequent and shorter-duration risks that would be expensive to meet with a combustion turbine generator. Investing in demand-side resources instead of natural gas would also complement the growing focus on other aspects of utility planning, such as beneficial electrification, energy efficiency, building electrification, and demand response.

One example of how utilities and regulators can increase transparency and competitiveness during integrated resource planning is finding creative ways to integrate new distributed resources. For example, an innovative transaction structure for commercial energy efficiency enables a utility to procure energy from energy efficiency developers through fixed-price contracts similar to power purchase agreements for wind and solar developments. The underlying principle of the transaction structure is that it takes the demand-side benefits of energy efficiency and creates a model that treats it the same as the supply side with investors. If adopted at scale, large commercial buildings in a utility's service territory could become a grid asset where some entity is involved and incentivized to ensure that the building performs in terms of energy use. Within this model, commercial buildings can act as energy storage and flexibility resources that complement variable renewables. Buildings are enormous thermal batteries, but there is no process to integrate buildings with the grid. The technology exists, but there is no transaction structure to realize the benefits. Lastly, with reduced net demand from large commercial buildings, utilities can use the additional capacity on the grid to meet demand from other loads in transportation and industry.

Increased awareness of demand-side resources could also enable more regulatory innovation and utility investment into new technologies and financial models that would provide both resource adequacy and decarbonization benefits. It also integrates previously isolated utility planning areas and programs with resource planning and procurement. To inform regulation and policy, regulators could ask utilities to model transportation and buildings in high electrification scenarios to understand the benefits and risks of relying on new and unfamiliar resources to provide resource adequacy and operational flexibility services. Once regulators and utilities identify the opportunity and quantify the benefits and costs, they can develop programs and procurement strategies to invest in these resources.

5.8. Increasing regional resource adequacy planning and including transmission as capacity

In many cases, the transmission infrastructure that connects two geographically diverse systems can provide a cheaper alternative to procuring resources solely within state boundaries or a utility's service territory. Spatial differences in weather decrease the correlation of demand and resource availability; cloud cover and wind speeds vary across large areas. Local demand patterns also vary across regions. Climate change is increasing the probability and impact of extreme weather, but transmission can connect areas with abundant supply to those experiencing a shortfall.

It will be more expensive if every planning region procures independent resources to meet individual planning reserve margins. For example, modeling conducted by Public Service Company of Colorado in support of its 2021 Clean Energy Plan filing indicated that a 400 MW interconnection to the Pacificorp East balancing authority via its new TransWest Express transmission project could reduce their planning reserve margin by four percentage points. Increasing the interconnectedness of local systems and planning areas through transmission can decrease overall variability in renewable energy generation, mitigate the risk of localized system peak demand periods, and potentially reduce the localized impact of extreme weather and other causes of correlated outages.

In light of these advantages, including transmission capacity expansion as available resources in resource adequacy planning processes is prudent, especially in regions with increased loss of load risk and insufficient transmission capacity. However, sufficient details into the modeling inputs required for an individual system's chronological stochastic resource adequacy must be available to assess a neighboring region's ability to share resources. This level of cooperation between planning entities likely requires market participation.

6. Looking Beyond Traditional Resource Adequacy Analysis to Assess Whole System Reliability

As shown in the above reports, studies, and papers on resource adequacy, current approaches to resource adequacy planning contain numerous challenges. Utility regulators cannot mitigate all the reliability risks associated with increasing penetrations of variable renewables, climate change, extreme weather, and increased dependence on natural gas with better methodology in probabilistic resource adequacy planning. More analysis is needed beyond resource adequacy modeling to identify potential capacity shortfalls, policy gaps, and operational risks associated with more wind and solar and less coal generation.

A recent report from Energy Innovation, LCC, in collaboration with Telos Energy and GridLab, was the first study to put together all of the recommendations above and apply them to the California electric grid.[26] The report's authors studied California's reliability impacts of achieving 80-90% carbon-free electricity by 2030 as an interim target to 100% by 2035. The purpose of the study was to stress test multiple clean energy portfolios to identify potential reliability implications of achieving higher penetrations of carbon-free energy. The study authors designed the stress conditions to reflect viable scenarios that a future system may face. This study presents a modeling approach that the Colorado PUC could replicate for Colorado.

[26] GridLab. (2022). *Reliably reaching California's clean electricity targets: Stress testing an accelerated 2030 clean portfolio*. www.gridlab.org/publications

6.1. Testing multiple portfolios is key to understanding the role of specific policies and resources

The authors first designed three portfolios that achieved 85% carbon-free electricity by 2030 using the RESOLVE capacity expansion model used in the California Joint Agencies SB 100 Report.

- A *base portfolio* with the California Energy Commission's Integrated Energy Policy Report "mid-mid" demand case.
- A *diverse clean portfolio* with 2 GW of geothermal and 4 GW of offshore wind capacity baked into the model as "policy mandates" and the same mid-mid demand case from the California Energy Commission's Integrated Energy Policy Report.
- A *high electrification portfolio* with accelerated EV adoption and increased building electrification demand (assumed 100% EV sales by 2035). The additional EV and building load increased demand by 15% compared to the mid-mid demand case. The high electrification scenario has the same geothermal and offshore wind capacity mandates as the diverse clean portfolio.

The authors configured the RESOLVE models for the diverse clean and high electrification portfolios with 2 GW of geothermal and 4 GW of offshore wind capacity by 2030. The 2 GW of geothermal generation resources was a placeholder for any dispatchable carbon-free energy resource. The output from the capacity expansion modeling includes total installed capacity by technology and location.

The methodology used in the study also deviated from traditional modeling designs by modeling solar PV interconnected onto the distribution grid as a supply resource rather than integrating it into the net-load profile. This purpose was to more accurately model distributed solar with weather data (and more aligned with utility-scale solar PV modeling), allowing the model to capture weather variability and generation diversity throughout the state. With an increased granularity in the generation of wind and solar data generation, the study authors could better identify the likelihood of low renewable energy generation events over multiple days.

Next, the study modeled each of the three portfolios in a PLEXOS unit commitment and dispatch model that simulated hourly unit commitments across Western Interconnection at a zonal resolution. PLEXOS allows for a more detailed representation of the Western Interconnection, which is vital to understanding the imports and exports of energy across diurnal and seasonal variations. Including the WECC in the unit commitment and dispatch model was especially important for California to assess the state's reliance on economic energy imports.

Each portfolio was then run through eight years of coincident solar and wind data and one year of demand data. Then, the study tested all three portfolios against stress conditions that would impact varying aspects of California's overall system reliability in 2030. Stress scenarios included the retirement of low capacity factor gas plants, depressed hydropower resource availability, and retiring all coal plants in the WECC by 2030 and replacing them with wind, solar, and storage. The portfolios were stress-tested across eight years of coincident wind and solar data, then tested simultaneously against all these stress conditions. A final scenario

replicated the circumstance of the August 2020 heat wave that led to rolling blackouts in the state. The study ran 260 individual simulations through the PLEXOS production cost model.

6.2. Building out future resource portfolios

Under the base portfolio, RESOLVE deployed 25 GW of wind, 17 GW of stationary battery energy storage, and 11.5 GW of onshore wind. Intentionally building out 2 GW of geothermal and 4 GW of offshore wind in the diverse clean portfolio reduces the capacity of solar, battery storage, and pumped hydro needed by 13 GW, 4 GW, and 2 GW, respectively. In the high electrification portfolio, RESOLVE built out an additional 15 GW more solar than the diverse clean portfolio and a further 4 GW of pumped storage hydro compared to the diverse clean portfolio (with the same battery energy storage capacity as the base portfolio).

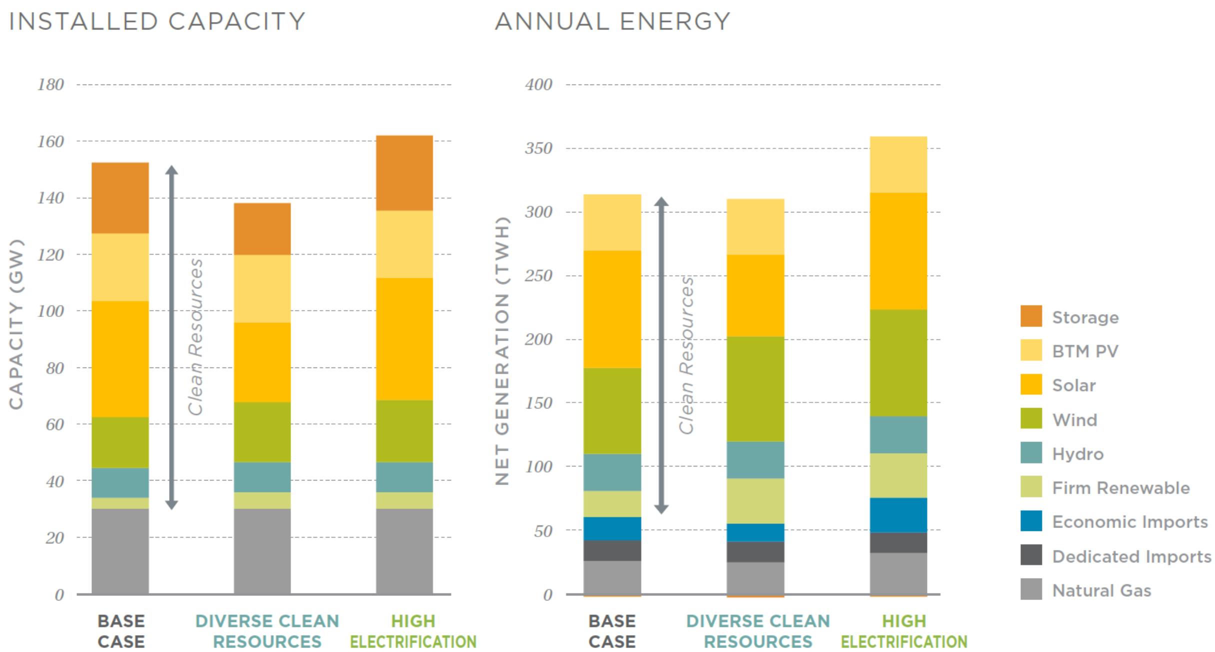


Figure 17. Installed capacity and energy generation by resource type for each portfolio. (*Source: Energy Innovation, LLC, GridWorks*)

By adding 2 GW of geothermal and 4 GW of offshore wind to the diverse clean resources portfolio, total solar additions are much more in line with current solar deployment rates in California. However, the diverse clean and high electrification portfolios cannot meet the pace of deployment with existing policies and adoption rates. These resources include onshore wind, offshore wind, and geothermal or another firm dispatchable carbon-free resource.

6.3. Unit commitment modeling to test each portfolio against future operational uncertainties

Next, the study authors modeled each portfolio against the stress conditions in PLEXOS for all the weather years to further test against future uncertainties. Although this analysis is deterministic, it is impossible to test each portfolio against all potential future uncertainties. Still, it can help to identify the significant drivers of future risks that could impact the resource adequacy of highly decarbonized power systems. For Colorado, researchers could

select specific sensitivities based on the particular conditions for the state. Again, this process aims to identify the future risk of possible outcomes today and craft policy to address risks and uncertainties to be better prepared. Current resource adequacy analyses cannot extract this information due to a lack of insights into specific system operability and behavior of multiple portfolios at hourly dispatch resolution.

For California, the study identified the following sensitivities to test each of the three portfolios against:

- Retired 11.5 GW of the remaining 24 GW of in-state natural gas capacity, all operating at less than 20% annual capacity factor. Retirements of natural gas capacity can alternatively target plants in disproportionately impacted communities using EPA or other environmental justice screening tools.
- Used the 10th percentile hydro year from 2001-2020, which reflects the increased likelihood of persistent drought conditions in the West that will limit reservoir hydro availability.
- Retired all remaining coal in the WECC totaling 14.3 GW, and replaced them with wind, solar, and storage resources to match the total energy generated, which resulted in an additional 22.6 GW of new resources.
- Restricted dedicated and economical electricity imports into California during summer peak demand periods to 13.1 GW, which the study found consistent with historical import constraint limits. Transmission availability and high demand were the primary factors of import scarcity modeled.
- Increased load variability and the impact during the summer months. The study also tested each of the portfolios against the August 2020 event.
- Increased demand flexibility by allowing load shifting to provide a capacity and energy service; resources included industrial processes, pumping loads, heating and cooling, and EVs. Baseline simulations assumed shed behavior from demand response to provide capacity shedding.
- Combined stressor including scenarios 1-5.

The key finding from the study was that all three portfolios can provide reliable electricity in 2030 while still meeting the 85% clean electricity standard. The study also found that resource diversity (modeled as geothermal and offshore wind) reduced the amount of wind and solar PV required to meet the clean energy target. However, the California study authors noted that new policies would be necessary to ensure resource diversity given the favorable economics of variable renewables like wind and solar.

Additionally, stress testing the system by retiring the 11 GW of natural gas capacity shifted the temporal risk profile of the California system. With fewer natural gas reserves, the early morning periods in the summer months experienced elevated risks due to no solar capacity and depleted energy storage resources from the previous day. Regulators and decision-makers could also prioritize early retirements of natural gas generation using environmental justice screening tools in combination with grid strength and reliability needs. For example, battery energy storage resources could be strategically sited next to natural gas combined-cycle generators with low capacity factors or disproportionately impacted communities to utilize existing transmission and distribution infrastructure better and provide environmental justice and localized air quality benefits.

Each of the three portfolios assumed a traditional demand response behavior from flexible demand resources that enabled the system operator to turn off those resources during

high-demand periods. To test an expanded demand response program, the study authors conducted a demand flexibility sensitivity to assess the value of providing load shifting, similar to what energy storage does. The authors of this report used the findings from a prior study out of Lawrence Berkeley National Lab that investigated the demand response potential in California to inform its assumptions and inputs in the production cost models. The results show that demand response behaves similarly to energy storage by providing dispatchable capacity and energy shifting during peak demand. Utilities and regulators would be best suited to proactively study demand response to assess the feasibility of implementing at scale compared to deploying battery storage at scale.

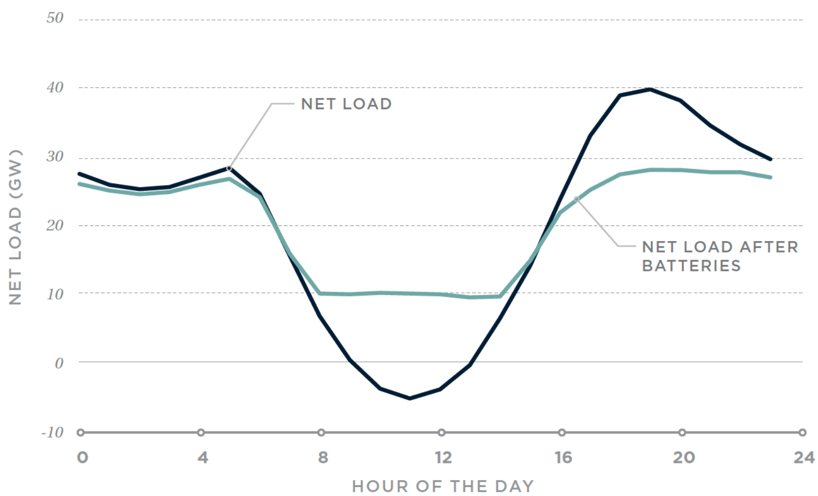


Figure 18. Battery storage reduces the diurnal ramp requirements in the late afternoon as net demand increases (*Source: Energy Innovation, LLC, GridWorks*)

Battery energy storage capacity increased by 11 to 15 GW by 2030 as a part of capacity expansion modeling. Energy storage provides many services, including summer peaking capacity during net-load periods, reduced duck curve ramp requirements by 42%, energy shifting of wind and solar, and ancillary services such as spinning and regulation reserves. As a hedge against battery supply chain issues and longer-term development timelines, demand response could be viewed similarly to energy storage to provide capacity and energy services. Demand response from flexible demand-side resources could also provide valuable and much-needed resource diversity. Including demand response modeling scenarios into new resource adequacy modeling frameworks could help quantify the benefits of investing in one of the cheapest energy sources.

6.4. Deep dive into specific meteorological events

The California study also looked at the ability of the California electricity system to remain resilient to extended periods of low renewable energy production from wind and solar, defined by the study team as consecutive days of combined wind and solar output below 30% of the daily load.[27] Planners, utilities, and regulators should expect this event to occur more frequently in the winter during December and January. The California system was able to weather these events in the winter due to surplus gas capacity and excess capacity in the rest of the WECC that is available for imports.

[27] Justin Sharp. (May 2022). *Meteorological Deep Dive of Low Renewable Energy Periods in Accelerated 2030 California Clean Electricity Portfolios*. Sharply Focused & GridLab. https://gridlab.org/wp-content/uploads/2022/05/GridLab_California-2030-Meteorological-Deep-Dive.pdf

As part of the study's meteorological deep-dive, the team assessed three instances of extended periods of low wind and solar generation across their modeled weather years. The meteorological events exhibited similar characteristics: an area of high pressure between the Great Basin and the Rocky Mountains that acts as a barrier to incoming weather systems, dampening wind speeds and creating a consistent cloud cover limiting solar generation in California. These events can occur 3-5 times per decade according to the weather years used in the analysis.

The study found that areas in the WECC, particularly in the desert southwest and Rocky Mountain regions, experience higher than average winter wind speeds. Most of the WECC sees low solar during these events. Resource planning could benefit from greater insight into the meteorological events that can impact future system resource adequacy, including lesser dependence on fossil fuel generation resources. For example, in the weather event described above, with a high ridge causing extended periods of low solar and wind in California, the state relies on imports from the WECC.

Interestingly, the meteorological deep-dive discovered certain areas with low annual capacity factor wind resources that exhibited elevated wind speeds during these events. If properly planned, wind sited in these areas can provide sufficient imported energy for California to remain resilient during low in-state renewable generation. The authors referred to these wind resources as "peaking wind" generation, wind generation resources with lower-than-average annual capacity factors but with correlated output to these extreme or infrequent weather events that can provide outsized value. For California, the authors identified multiple areas that could experience elevated wind speeds when most of the state experiences low resource availability, including the Desert Southwest, Baja California, and the west side of the Cascades and Sierra Nevada. The study recommends that future resource planning include locational resource planning informed by meteorological insights.

6.5. Important takeaways from the California 2030 study

Other utilities and planning entities in Colorado can easily replicate the modeling methodology used by the authors of the California study. The iterative process of capacity expansion modeling and resource adequacy analysis is the best way to ensure that future power systems are reliable. Assumptions are no longer sufficient to ensure resource adequacy. Resource adequacy planning should include production cost modeling of chronological system operations across many correlated solar, wind, load, and weather years, with multiple portfolios tested against various stress conditions to determine the system's resilience across all hours. Following resource procurement, utilities would ideally conduct a follow-up resource adequacy analysis to assess the interactions between various renewable energy and energy-limited resources, as demonstrated in ELCC studies. An iterative resource adequacy process incorporating other modeling tools would also address the portfolio and saturation effects with ELCC capacity accreditation.

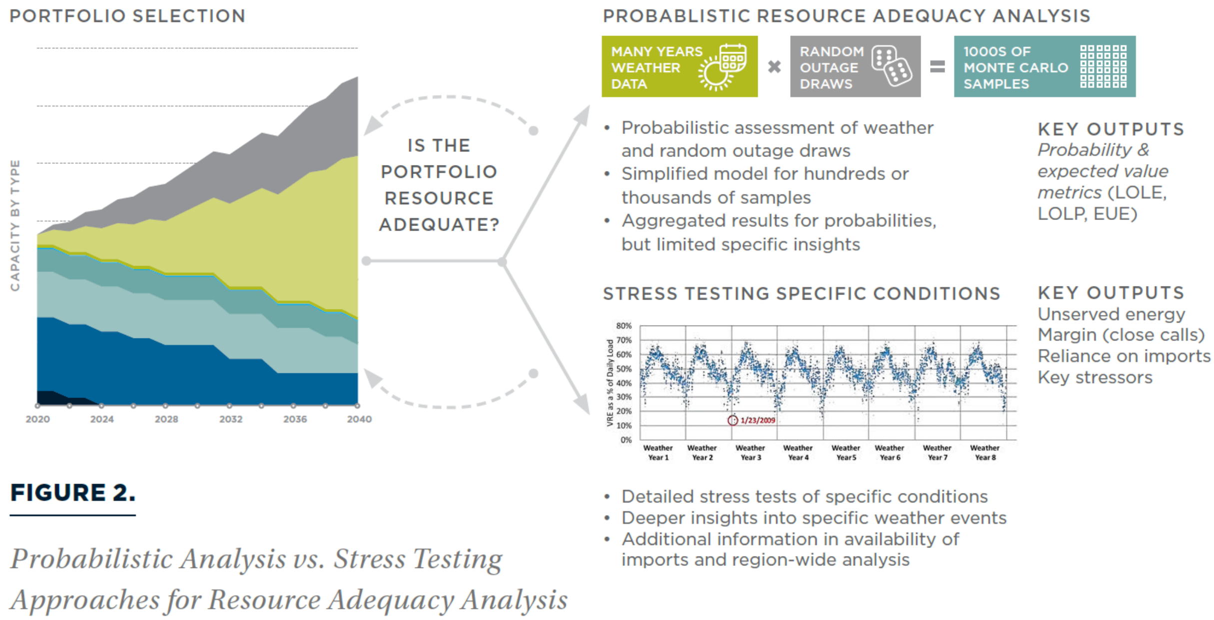


Figure 19. An iterative approach to resource adequacy analysis. (*Source: Energy Innovation, LLC, GridWorks*)

Traditional capacity expansion models such as RESOLVE do not perform chronological simulations. Still, production cost models, such as PLEXOS, can analyze system reliability at an hourly resolution with chronological operations through each of the 8,760 hours of a given weather year. Stress testing the current system and other portfolios is complementary to traditional capacity expansion modeling and traditional probabilistic resource adequacy analysis done in integrated resource planning. Capacity expansion modeling can predict the buildout of multiple carbon-free generation resources in a future date. The unit commitment and production cost modeling can further analyze the granular operations of the system at an hourly resolution.

Traditional resource adequacy processes perform stochastic analyses using random samples of generator forced outages and multiple supply and demand years to meet predetermined reliability criteria–such as 0.1 LOLE–to determine a planning reserve margin for the system in future years. The output of a resource adequacy analysis determines the capacity required to meet future demand, which serves as the outcome that a capacity expansion model such as RESOLVE will solve. Thus, the outputs of resource adequacy analysis serve as inputs into capacity expansion planning to determine resource procurement needs. However, the resulting portfolio mix determined by the capacity expansion modeling never gets re-analyzed to ensure the new system provides sufficient resource adequacy. Instead, models assume the entire system is reliable with a planning reserve margin. Planners accept that the system remains reliable even if the final portfolio mix differs from the capacity expansion modeling results.

The findings from the California study aligned with other recent studies cited in this report: resource adequacy planning needs to adapt to a changing resource mix, specifically in the modeling tools and methodologies. Capacity expansion models have limitations in their applications. They do not provide chronological analyses of the systems they are modeling, do

not include robust modeling against multiple weather years, and only look at a sample of days in the year with a low geographic and technical resolution of renewable energy resources. The study recommends using capacity expansion modeling as a screening tool within a more extensive process that includes production cost modeling and resource adequacy analysis.

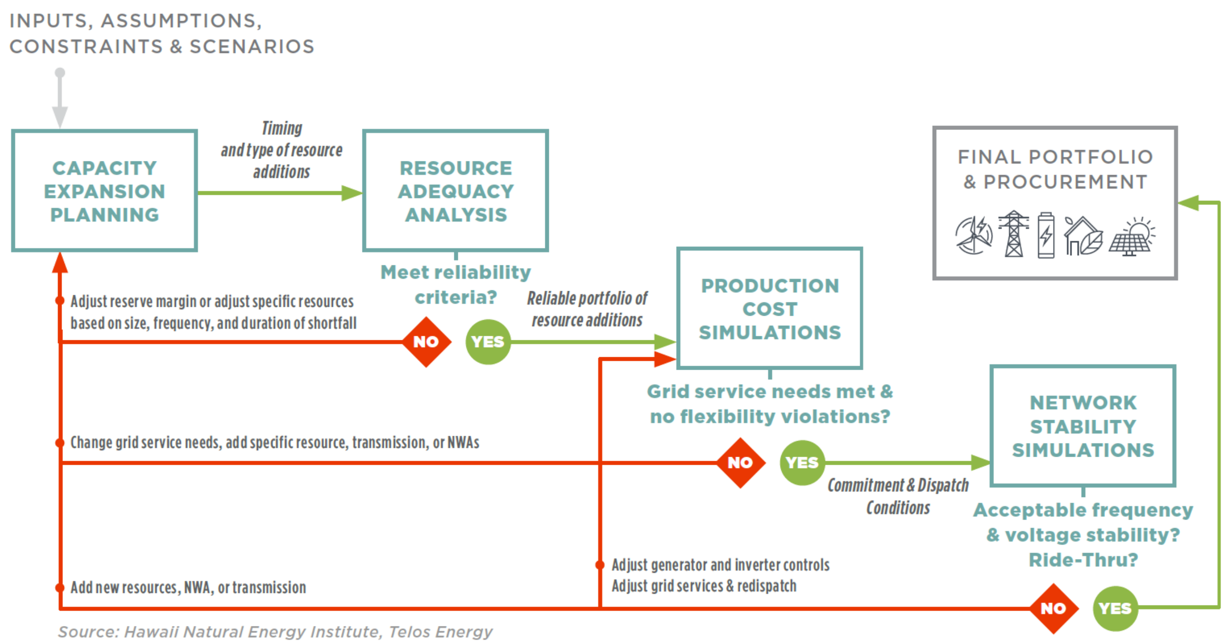


Figure 20. The proposed modeling framework incorporates multiple dimensions of analysis. (*Source: Energy Innovation, LLC, GridWorks*)

The authors propose an iterative approach: first, probabilistic resource adequacy modeling to quantify technology ELCC for input into a capacity expansion model to identify a portfolio mix of resources. Next is developing alternative portfolios to test deployment feasibility, policy planning, and operational performance. Then, probabilistic resource adequacy modeling analyzes the portfolio ELCCs and stress-test specific events, situations, and scenarios. Finally, production cost modeling determines shortfall events' size, frequency, duration, and timing. From there, planners can adjust the portfolios with specific resource additions or changes needed to address the shortfalls (including demand response, battery storage, locational resources, and transmission).

The importance of the study for California is that it has provided insight into current policy shortfalls and can ultimately be used to help inform new policies in subsequent state legislative sessions. Each portfolio represents a possible future resource mix that can give policymakers direction on where to focus priorities for new policies and even understand the implications of already enacted policies such as electrification and emissions reduction mandates for specific sectors.

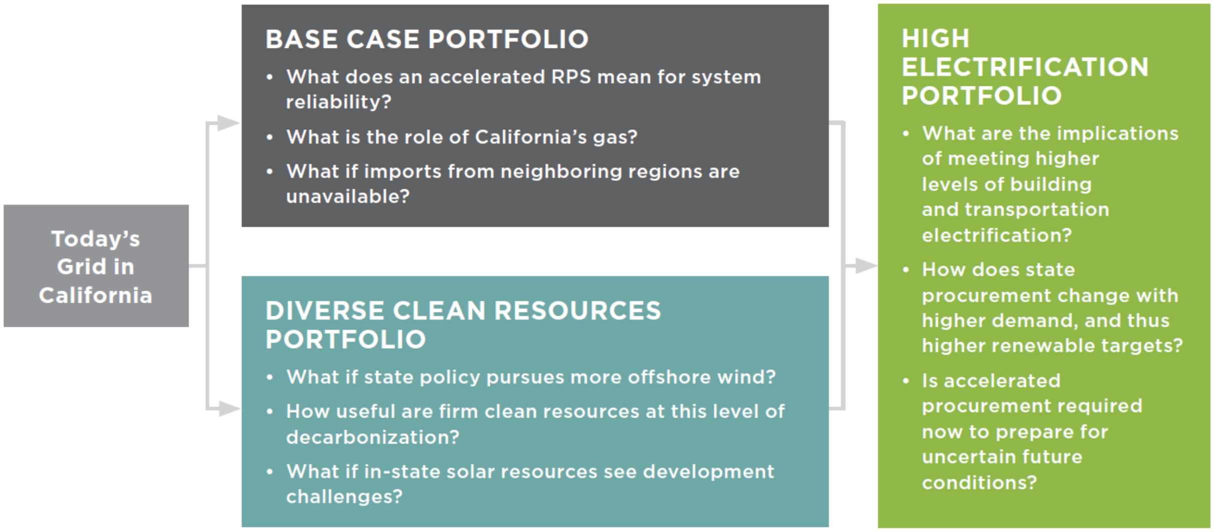


Figure 21. Questions that each of the portfolios can answer. (*Source*: *Energy Innovation, LLC, GridWorks*)

Decision-makers could consider applying this framework to Colorado and the rest of the WECC. Colorado shares many of the same underlying characteristics as California. Colorado plans to retire hundreds of megawatts of coal power plants by 2031. Similarly, Colorado already has over 4 GW of wind energy online and is expected to bring over 1 GW of solar online over the next few years. The State of Colorado could apply the same methodology to a similar study that can expose some of the underlying risks of the current trajectory and the policy considerations that could inform future legislative sessions.

7. Conclusions

Utilities and regulators in the 20th century assumed that the total nameplate capacity of fossil fuel generation resources was available at all hours. They assessed the expected peak demand for a given planning outlook period, and generation was procured and "stacked" to meet the expected peak demand plus a planning reserve margin. Resource adequacy planning must adapt to drivers such as climate change, extreme weather, electrification of buildings and transportation, distributed energy resources, flexible generation, and increasing penetrations of variable renewable energy resources.

System requirements to maintain resource adequacy change as the power system's resource mix changes, and analyses must adapt to ensure economically efficient resource procurement. Similarly, the metrics used to characterize shortfall events don't provide adequate information on the size, frequency, duration, and timing of shortfalls; the number and probability of these events are not enough to identify the right resources needed to meet shortfalls.

Modeling analyses that include chronological Monte Carlo methods need to analyze resource adequacy over many weather scenarios because reliability risks are no longer isolated during peak demand periods. In the near term, periods of highest risk will shift to the net-load peak, eventually shifting to extended periods of low solar and wind resource availability, likely during the winter months. As the penetration of more variable and energy-limited resources increases–along with other drivers such as extreme weather, climate change, and demand

variability–the times when the system is most strained could occur at varying times throughout the year that requires a more thorough analysis of all hours.

Resource procurement and capacity accreditation using the ELCC method has limitations for longer-term system planning, given the underlying saturation and portfolio effects. While recent analysis suggest moving away from ELCC, the evaluation method is best used across all resources, particularly thermal generators such as natural gas plants, due to the increasing correlated outage risk of disruptions to in-time delivery of natural gas fuel supplies, temperature deratings of natural gas generation infrastructure across the supply chain, and frequency of extreme weather events due to climate change. Although not as predictable as the retired fossil fuel resources they replace, renewable energy resources still deliver energy aligned with the weather that can be reliably forecasted and predicted. The effective or discounted capacity they offer to the system is a time-dependent calculation that continuously changes as the resource mix changes. Alternatively, the energy these resources deliver to the system, at which time of day, month, season, and year, and in which order they are dispatched, is becoming increasingly more important with increasing penetrations of variable renewables, climate change, and extreme weather.

Traditional resource adequacy modeling must adapt to address the needs of current and future power systems. Today's planning methodologies fall short in identifying emerging risks: climate change increases the probability of shortfall events, but regulators don't have sufficient insight into the size, frequency, duration, and timing of those shortfall events. Most new resource additions on the grid include solar, wind, and energy storage. The demand side is also transforming, with load flexibility becoming an asset due to increased penetration of distributed energy resources and electrification of transportation and other end-uses. This transition is concurrent with the rapid acceleration of coal retirements and increased reliance on natural gas resources.

This paper has aggregated existing literature and research proposals that aim to address the current deficiencies in resource adequacy planning. The purpose of this research is to initiate conversations around how the Colorado Public Utilities Commission, its regulated electric utilities, and valued stakeholders can address the need to maintain a reliable electric system in Colorado throughout the energy transition to 100% carbon-free electricity. Institutional change is challenging to overcome, and today's planning processes have been in place for decades. The system is changing, and the tools and strategies responsible for ensuring cost-effective and efficient reliability also need to change.

Sources

1. Western Electric Coordinating Council. (December 2021). *2021 Western Assessment of Resource Adequacy*. https://www.wecc.org/Administrative/WARA%202021.pdf
2. North American Electric Reliability Corporation. (May 2022). *NERC Summer Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf
3. Nick Schlag, Adrian Au, Karl Walter, Ruoshui Li, Roderick Go, Tristan Wallace, Lakshmi Alagappan, Arne Olson. (February 2022). *Resource Adequacy in the Desert Southwest*. Energy + Environmental Economics. https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf.
4. PJM. (May 2022). *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid*. https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220517-annual/item-06---renewable-integration-study-ris-20---presentation.ashx
5. J. W. Jagdmann, J. W. Betkoski, III, T. R. Mathews, A. Rendahl, M. Schuerger, T. J. Thomas, E. J. Nethercutt. (July 2021). *Resource Adequacy Primer For State Regulators*. National Association of Regulatory Utility Commissioners. https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042
6. Carden, K. and Wintermantel, N. (January 2013). *The Economic Ramifications of Resource Adequacy White Paper*. Eastern Interconnection States Planning Council and the National Association of Regulatory Utility Commissioners. Astrape Consulting. https://pubs.naruc.org/pub.cfm?id=536DBE4A-2354-D714-5153-70FEAB9E1A87
7. North American Electric Reliability Corporation. (July 2018). *Probabilistic Resource Adequacy Metrics Technical Reference Report*. https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf
8. Bradfield Lyon et al. 8 November 2019. *Projected increase in the spatial extent of contiguous US summer heat waves and associated attributes*. Environmental Research Letters Volume **14** Number 114029. https://iopscience.iop.org/article/10.1088/1748-9326/ab4b41
9. Sinnott Murphy, Fallaw Sowell, Jay Apt. (2019). *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence*. Applied Energy. Volume 253. 113513. ISSN 0306-2619. https://doi.org/10.1016/j.apenergy.2019.113513
10. Somani, A.; Datta, S.; Kincic, S.; Chalishazar, V; Vyakaranam, B.; Samaan, N.; Colotelo, A., Zhang, Y.; Koritarov, V; McJunkin, T.; Mosier, T.; Novacheck, J.; Emmanuel, M.; Schwarz, M.; Markel, L.; and O'Reilley, C. (August 2021). *Hydropower's Contributions to Grid Resilience*. U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. Washington, D.C. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-30554.pdf
11. Josh Novacheck, Justin Sharp, Marty Schwarz, Paul Donohoo-Vallett, Zach Tzavelis, Grant Buster, and Michael Rossol. (2021). *The Evolving Role of Extreme Weather Events in the U.S. Power System with High Levels of Variable Renewable Energy*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-78394. https://www.nrel.gov/docs/fy22osti/78394.pdf
12. Isaac Bromley-Dulfano, Julian Florez, Michael T. Craig. (2021). *Reliability benefits of wide-area renewable energy planning across the Western United States*. Renewable Energy. Volume 179. Pages 1487-1499. ISSN 0960-1481. https://doi.org/10.1016/j.renene.2021.07.095
13. Colorado Public Utilities Commission. September 21, 2022. *Commission Decision Addressing Applications For Rehearing, Reargument, Or Reconsideration Of Commission Decision No. C22-0459*. Proceeding No. 21A-0141E Public Service of Colorado - 2021 ERP and CEP. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=29398
14. Denholm, Paul, Wesley Cole, A. Will Frazier, Kara Podkaminer, and Nate Blair. (2021). *The Four Phases of Storage Deployment: A Framework for the Expanding Role of Storage in the U.S. Power System*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77480. https://www.nrel.gov/docs/fy21osti/77480.pdf

15. Gridworks. (March 2021). *Resource Adequacy: Reliability Through the Clean Energy Transition*. https://gridworks.org/wp-content/uploads/2021/03/Resource_Adequacy_Reliability_through_Transition.pdf
16. R. Gramlich. (November 2021). *Ensuring Low-Cost Reliability: Resource Adequacy Recommendations for a Clean Energy Grid*. Grid Strategies, LLC and American Council on Renewable Energy. https://acore.org/resource-adequacy-report/
17. Schröder, T. and Kuckshinrichs, W. (2015). *Value of lost load: An efficient economic indicator for power supply security? A literature review*. Frontiers in Energy Research, 3(55), DOI: 10.3389/fenrg.2015.00055 https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full
18. California Public Utilities Commission. July 16, 2021. *D2107014 Track 3B.2 Issues Decision*. Proceeding: R1911009. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF
19. Mauch, B.; Millar, D; and Dorris, G. (June 2022). *Resource Adequacy Modeling for a High Renewable Future*. NRRI Insights. https://pubs.naruc.org/pub/DC366C78-1866-DAAC-99FB-4C0759DB57C5
20. Advanced Energy Economy. (March 2022). *Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources*. https://www.aee.net/aee-reports/getting-capacity-right-how-current-methods-overvalue-conventional-power-sources
21. J. Dison, A. Dombrowsky, and K. Carden. (March 2022). *Accrediting Resource Adequacy Value to Thermal Generation*. Astrapé Consulting. https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf
22. N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang. (August 2020). *Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy*. Energy and Environmental Economics, Inc. https://www.ethree.com/elcc-resource-adequacy/
23. 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
24. Hogan, M., and D. Littell. (June 2020). *Get What You Need: Reclaiming Consumer-Centric Resource Adequacy*. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2020/06/rap-hogan-littell-consumer-centric-resource-adequacy-2020-june.pdf
25. GridLab. (2022). *Reliably reaching California's clean electricity targets: Stress testing an accelerated 2030 clean portfolio*. www.gridlab.org/publications
26. Justin Sharp. (May 2022). *Meteorological Deep Dive of Low Renewable Energy Periods in Accelerated 2030 California Clean Electricity Portfolios*. Sharply Focused & GridLab. https://gridlab.org/wp-content/uploads/2022/05/GridLab_California-2030-Meteorological-Deep-Dive.pdf