The Capacity Accreditation of Demand Response in Southwest Power Pool

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ABSTRACT

The Southwest Power Pool (SPP) is experiencing rapid system transformation driven by increasing extreme weather risks, accelerated fossil retirements, continued adoption of variable and energy-limited resources, and significant load growth, particularly from data centers and other large loads. These developments have increased resource adequacy (RA) challenges across both summer and winter seasons, prompting updates to SPP's planning reserve margin requirements. At the same time, supply chain constraints and interconnection backlogs continue to delay new resource development, heightening near-term reliability concerns. This study evaluates the reliability contribution of flexible demand response (DR) as a near-term solution to support system adequacy. Using E3's Renewable Energy and Capacity Planning (RECAP) model and SPP's Effective Load Carrying Capability (ELCC) framework, the analysis examines how DR duration (between 4-hour and 10-hour), seasonal call limits (up to 10 calls), and market penetration (adding incremental 2-6GW DR) influence DR capacity value. Results show that 4-hour DR provides 36–83% ELCC across seasons from 2025–2030, while 10-hour DR can achieve 82–100% ELCC, with particularly strong performance during multi-day winter stress events. On average, around 10 hours of DR deployment per year are required to achieve high ELCC, with up to 85 hours needed in the most severe weather years. Findings indicate that DR can deliver reliability value comparable to, and in some cases exceeding, traditional supply-side resources. With appropriate accreditation and market design, DR can help SPP manage fast-growing loads and bridge near-term reliability gaps while longer-lead investments in transmission and generation progress.

Introduction to Resource Adequacy

The North America Electric Reliability Coordinator (NERC) defines resource adequacy (RA) as "the ability of an electric system to supply the aggregate electrical demand (including losses)" (NERC n.d.). RA planning includes loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load, including seasonal patterns, weather sensitivity, hourly patterns; as well as its resources, size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities and market operators, like SPP, seeking to provide reliable service to their customers.

Today, modern resource adequacy planning relies primarily on Monte Carlo loss-of-load-probability (LOLP) modeling, which simulates thousands of plausible system conditions to quantify system reliability risk and specific resource capacity contribution to meeting reliability needs. LOLP models are also used to measure the capacity needed in megawatts to meet a specified loss-of-load standard or the Total Reliability Need (TRN). This has historically been simplified into a planning reserve margin (PRM) framework: a planning requirement to maintain a margin of capacity above expected peak load to account for (1) the potential for higher loads than expected, (2) the possibility of generator failures, and (3) the megawatt equivalent of hourly operating reserves needed during energy emergency conditions. While PRM requirements vary from one system to another due to each system's unique characteristics, commonly observed values are 15-30% above median peak demand on an "installed capacity" (ICAP) basis. Figure 1 illustrates the concept of a planning reserve margin above the median peak demand.

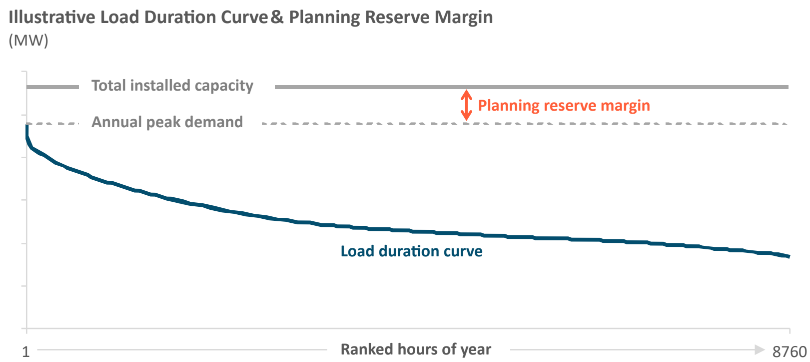

Figure 1: Illustrative Planning Reserve Margin

For decades, this framework provided a simple, transparent, and robust approach to ensuring resource adequacy. Because power systems relied mostly on firm resources, a system that maintained a PRM sufficient to serve load reliably during the peak load hour would also serve load reliably during all other times of the year. And because resources were generally alike in their ability to operate during peak demand conditions, differentiating their reliability contributions was either unnecessary or could be done outside of a rigorous loss-of-load modeling framework (such as through adjustments for resource-specific outage rates). In the 1990s and 2000s, as organized wholesale electricity markets arose, this same approach was adapted for use in the design of capacity markets and resource adequacy pooling programs. These programs used the same basic principles to establish four key elements of capacity market design:

1. Modeling and Data: Development of a loss-of-load-probability (LOLP) model that can simulate the availability of loads and resources on an hourly basis across a wide variety of weather conditions to identify periods in which an electricity system is vulnerable to reliability risks.
2. Need determination, how much total capacity is needed across the pool to meet the resource adequacy standard,
3. Capacity accreditation, how much each individual resource can be counted towards that requirement, and
4. Need allocation, how much responsibility each individual load-serving entity bears for the requirement of the system.

While the SPP's specific terminologies may differ, SPP's RA framework adheres to the same fundamental concepts and basic components. SPP's specific RA framework is discussed in more detail in a below section.

Current state of RA and Evolving RA Challenges

RA planning frameworks across North American markets have evolved to capture three key RA challenges: (1) shifting of the net peak periods or "critical periods", (2) incorporating fuel security of conventional resources, and (3) accrediting all resources, including large flexible loads and demand response programs, to meet the marginal reliability need (DOE 2024).

"Critical periods" are periods when the electricity system has reached or exceeded its maximum limits to serve electricity demand, meaning that loss of load has already occurred, is occurring, or is imminent (E3 2025b). From this definition, it naturally follows that during critical periods, any additional generation or load reduction would improve system reliability. Historically, those critical periods coincided almost exclusively with peak load, but in the future, critical periods will increasingly occur at different times of day and across different seasons due to combinations of high load and low resource availability. Depending on the load and resource availability alignment, some systems experience critical periods during summer, winter, or both seasons (ESIG 2021). Figure 2 illustrates the concepts between changing critical periods between a historical and future system. Generation or energy-limited resources that can adapt to changing critical periods would achieve higher capacity accreditations in utility planning and markets.

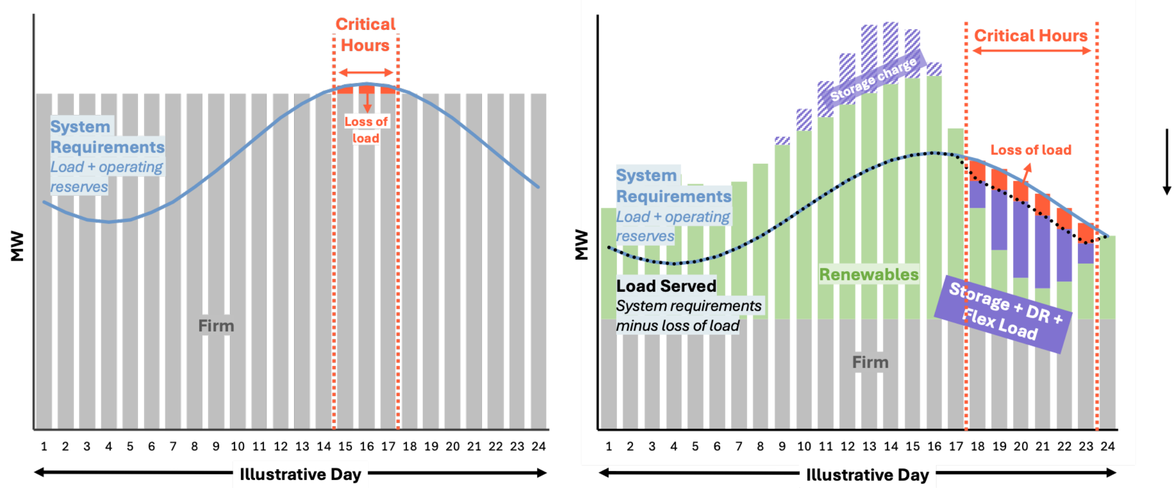

Figure 2: Comparison of Historical and Future Critical Periods

While much of the focus in recent years has been on the appropriate accreditation of variable energy resources, recent events have also exposed vulnerabilities in traditional practices that were previously not well understood for the treatment of conventional resources. During extreme winter storms, challenges related to fuel supply and correlated high outage rates of firm resources have been proximate causes of rotating blackouts in Texas and across the Southeast

(FERC and NERC 2021). The potential for significant quantities of firm generators to fail at the same time is not fundamentally dissimilar from a large quantity of wind or solar going offline due to widespread reduced wind conditions, cloud cover, or sundown.

Many grid planners today have or are starting to adapt capacity accreditation methods for variable and energy-limited resources (EPRI n.d.). Any accreditation approach must provide the marginal capacity signal, including its changing value as the portfolio and load dynamics evolve. The Effective Load Carrying Capability (ELCC) methodology is one such method that accurately captures marginal capacity value and can be extended to all resources types, including conventional thermal resources, variable renewables, energy-limited storage, and flexible loads (Garver 1966). Figure 3 illustrates the declining ELCCs of standalone solar and storage resources and the diversity impact of the combination of both (E3 2020; ERCOT 2022; ESIG 2023; NERC 2025b). The storage and diversity examples can be further extended to DR. In effect, DR can provide a similar function as storage when called upon to reduce load and its ELCC depends on its load reduction during the alignment with system critical periods.

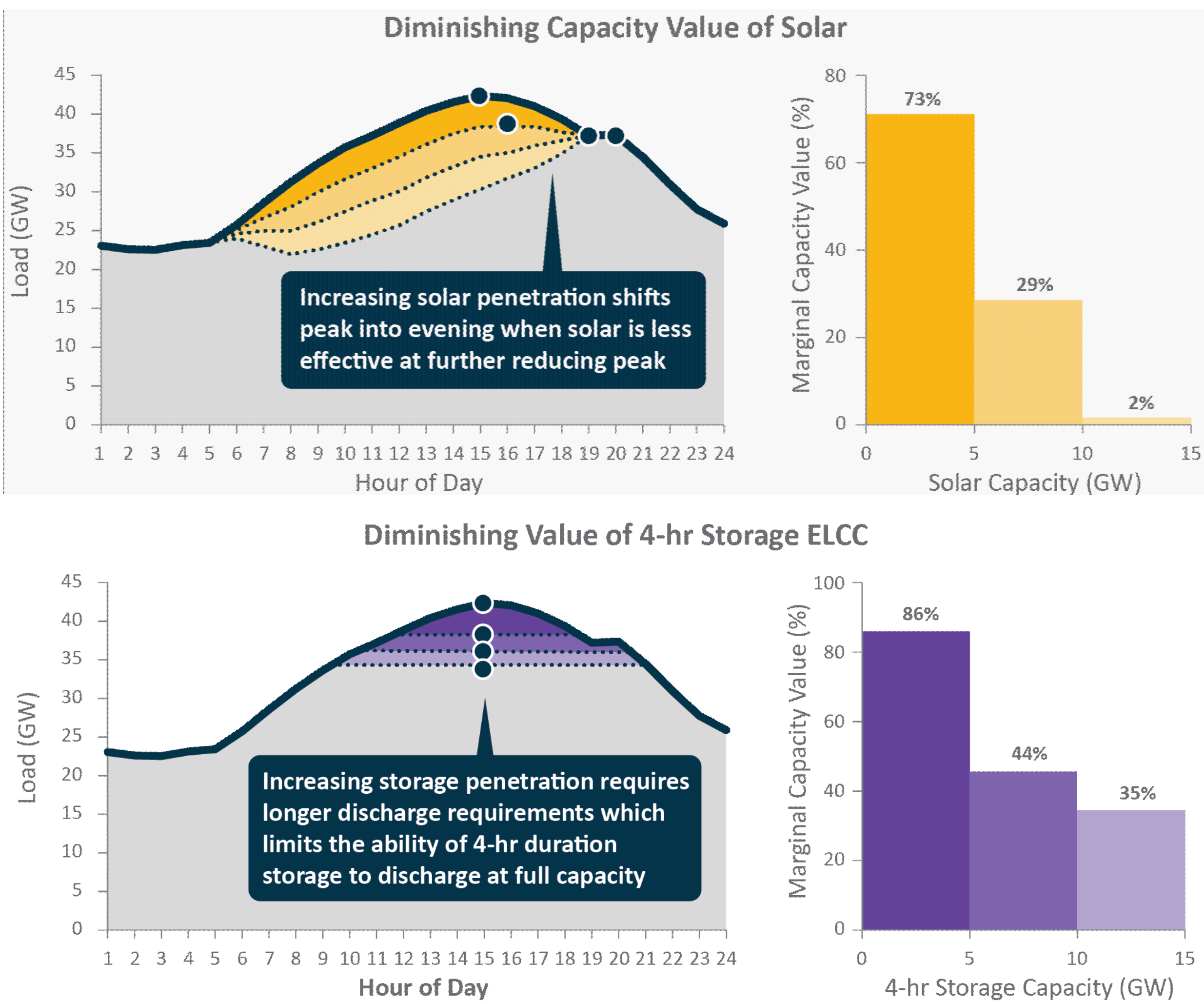

Figure 3: Illustration of the Diminishing Value of Solar and Storage and Diversity Benefits of Solar and StoragPe

With most North American markets today are facing unprecedented load growth from data centers and other large loads, markets are increasingly reforming market design to address new large-load flexibility and its capacity market participation as a form of demand response (EPRI 2024; Wilson, Zimmerman, and Gramlich 2024; NERC 2024). SPP's High Impact Large Load (HILL) and Conditional HILL (CHILL) framework, approved by FERC in January 2026, lets large loads connect on a non-firm basis in exchange for accepting curtailment during system stress (SPP 2026a). Comparable approaches are emerging elsewhere (ERCOT 2026; PJM 2026), and in June 2026 FERC directed all six RTOs/ISOs to reform their large-load tariffs along similar lines (FERC 2026). These interconnection-based mechanisms are conceptually distinct from their capacity value, but characterizes how large loads may participate in capacity markets and thus its accredited ELCC.

It is important to note that ELCC reflects a resource's probabilistic contribution to system adequacy. The more a resource is available and responsive during critical periods, the higher its accreditation. A high ELCC does not imply that DR is operationally interchangeable with thermal generation, but rather, a high ELCC implies resources are available during the rare periods that the system is near- or at reliability risk. DR is subject to call limits, seasonal availability, and other constraints between events and full program participation. All these constraints are captured in ELCC modeling and should be considered when interpreting accreditation results.

Introduction to SPP and the SPP RA Framework

SPP is a regional transmission organization coordinating the reliable operation of the bulk electric system and wholesale markets across 14 states in the central United States. The system's generation mix is characterized by substantial wind capacity and material shares of coal and natural gas generation. Like other US electricity markets, SPP is experiencing rapid change driven by increases in adoption of renewables and energy storage, traditional firm resource retirements, shifting weather patterns, and electricity demand (Wilson, Zimmerman, and Gramlich 2024).

SPP has an all-time summer peak demand of 56 GW occurring in 2023 and saw an annual 2024 energy consumption of approximately 278 TWh (SPP 2025a). The region is distinguished by its industry-leading wind resources, with a current peak wind output of 24 GW from approximately 35 GW of installed capacity. Alongside wind, SPP relies on a diverse generation mix that includes 22 GW of coal, 36 GW of natural gas-fired generation, and smaller contributions from nuclear (2 GW), oil-fired (2 GW), and hydroelectric (3 GW) resources. While solar and battery storage currently make up a small portion of the SPP resource mix, their capacity is expected to grow significantly in the coming years.

In 2024, wind generation supplied 38% of SPP's total energy, making it the single largest contributor to the mix. Natural gas followed with 29%, while coal accounted for 24%. Nuclear and hydro combined provided 7%, with the remaining 2% coming from solar, oil-fired units, and other sources.

Table 1: SPP Current Capacity Accreditation

Resource Type	Accreditation Method	2024-2025 Accreditation (% of nameplate capacity)[1]
Gas, Coal, Nuclear	ACAP - Installed capacity minus equivalent forced outage rates on demand (EFORd) & adjusted equivalent forced outage factor (EFOF)[2]	91% (Summer), 82% (Winter)
Hydro	Firm capacity obligations	100% of capacity obligation
Wind	ELCC by Tier, Tier 1 (with firm transmission) & Tier 2 (without)	18% (Summer), 31% (Winter)
Solar	ELCC by Tier, Tier 1 (with firm transmission) & Tier 2 (without)	62% (Summer), 37% (Winter)
Battery Storage	ELCC by duration (4hr, 6hr, 8hr) and by Tier	4hr: 65% (Summer), 48% (Winter) 6hr: 94%(Summer), 75% (Winter) 8hr: 100%(Summer), 75% (Winter)
Demand Response	See Table 2 for SPP-Specifics	

SPP's RA framework follows the framework described in the prior section. Load Responsible Entities (LREs) must ensure sufficient capacity to meet seasonal PRM requirements. Unlike some of the eastern markets, which rely on centralized capacity auction, SPP's LREs submit workbooks demonstrating sufficient accredited capacity to meet seasonal peak demand plus an applicable planning reserve margin (SPP 2025b). As of 2026, SPP's recently adopted summer PRM of 7% and winter PRM 15% (SPP 2025b). Following its accreditation reform approved in 2024, SPP applies different accreditation methods by resource type, including a Performance-Based Accreditation (PBA) approach, reported as Accredited Capacity (ACAP) for thermal resources and ELCC-based accreditation for variable resources, like wind and solar, and battery storage. Table 1: SPP Current Capacity Accreditation shows the current capacity accreditation methodologies for each resource type (SPP 2024a, 2026b).

Definition of Demand Response (DR) in SPP and Study Motivation

DR in SPP is currently concentrated among large industrial and commercial users (FERC 2024). Qualifying DR programs are treated as load modifiers to LRE's "Net Peak Demand". These participants often operate under interruptible tariffs or direct load control agreements with their LREs. The most common participants include industrial manufacturing facilities, pulp and paper mills, chemical processors, agricultural pumping loads, and municipal water treatment systems.

[1] Accreditation values shown for aggregate SPP resource class, prior to allocation of accreditation to individual SPP-registered resources.
[2] SPP thermal resources are accredited with net generating capability under Base PRM accounting. Thermal resources receive ACAP values under ACAP PRM accounting, as part of Performance Based Accreditation revisions. For ELCC resources, the same values are used under both Base PRM and ACAP PRM accounting.

DR encompasses a range of approaches that differ in how they reduce or reshape electricity demand during periods of system stress. DR is the most traditional form, where participating loads, such as industrial facilities, commercial buildings, or aggregated residential demand, are curtailed outright during an event, lowering system load in real time (curtailed DR). Shift DR instead moves consumption from critical periods to lower-risk periods, for example by pre-cooling buildings in the afternoon before a summer peak (Xu et al. 2004) or shifting EV charging to overnight hours. Other forms include shape DR, which permanently modifies load profiles through smart appliances or pricing signals. Together, these DR types provide different durations, magnitudes, and response speeds, allowing them to complement supply-side resources and enhance system reliability (FERC 2009). Table 2 describes each DR program in more detail.

Table 2: DR Program Types in SPP

DR Type	**Accreditation Method**	**Utilization**	**Status**[3]
Peak Demand DR Programs	Reduction in Load-Responsible Entity (LRE) Peak Demand Forecast	Typically called during Energy Emergency Alert Events[4]	Active
Market Registered DR Resource	ELCC + Energy Market Offer Curves	Economic dispatch into energy market, called before reliability registration	In development
Reliability Registered DR Resource ***Focus of this paper***	ELCC	Called during SPP critical periods	In development

This study evaluates DR capacity accreditation under an Effective Load Carrying Capability (ELCC) framework aligned with SPP's ELCC approach for variable resources and storage. We address three questions: (1) What is the ELCC-based capacity value of DR in SPP? (2) Which DR parameters most influence accreditation? and (3) How frequently must DR be dispatched to achieve high ELCC?

Methodology

The capacity accreditation of DR is determined by three key parameters: DR duration, DR seasonal call limit, and DR adoption. DR duration is the maximum number of hours DR is available per call. DR calls are restricted to once per day. The DR seasonal call limit is the total number of hours per season that DR can be dispatched. Finally, DR adoption is the magnitude (measured in MW) of load that will respond to the DR call for its full duration. DR adoption may

[3] Status as of September 2025
[4] A NERC Energy Emergency Alert (EEA) is a real-time emergency procedure used by grid operators to communicate capacity and energy shortages

therefore be lower than the average or maximum magnitude of load associated with the DR providers. Only the fraction of load that is registered to respond in each SPP Season is counted. For example, a single SPP customer may have 500MW of average load but only register 200MW as DR in Summer and 100MW as DR in Winter. This study quantifies the ELCC of DR in SPP in 2025 and 2030 across a range of expected and bookend values for these three parameters. Figure 4: DR Program Parameters Tested in this Study is an illustration of the three different parameters tested in this study.

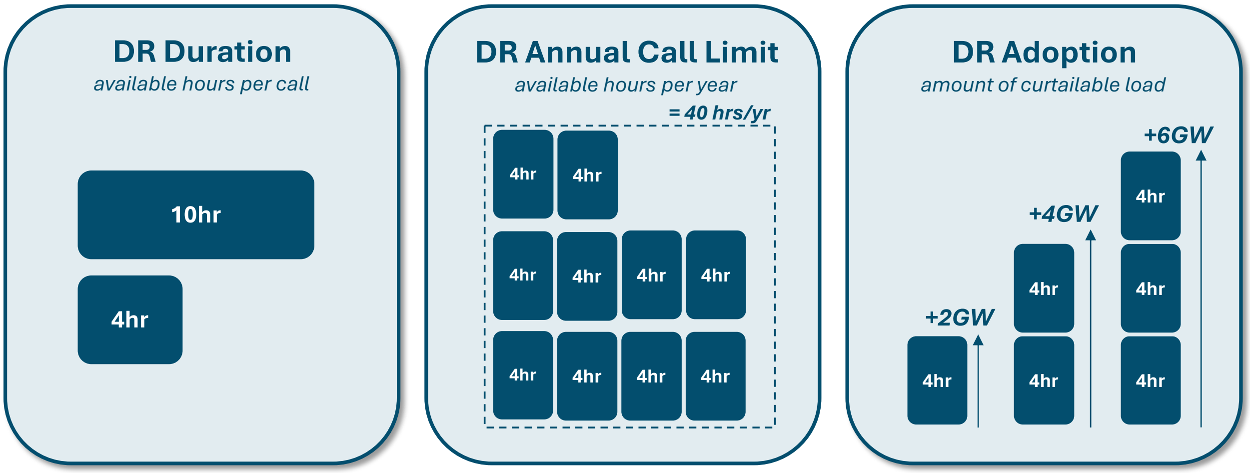

Figure 4: DR Program Parameters Tested in this Study

Longer durations are able to sustain through extended loss-of-load periods. Additional seasonal call limits can increase value if total calls are exhausted. Increasing DR penetration increase total curtailable load but elongates load-of-load periods.

Table 3 outlines the suite of parameters tested.

Table 3: Range DR Operating Parameters & Adoption Levels Evaluated

DR Duration *Available Hours per day*	**DR Seasonal Call Limit** *Available Hours per season*	**DR Adoption Level** *Available GW*
4 hours	40 - 120	2 - 6 GW
10 hours	100 - 300	2 - 6 GW

We estimate DR ELCC using E3's RECAP loss-of-load probability (LOLP) model. The SPP footprint is modeled as a single-zone system evaluated across 66 historical weather years (1954–2019) and 15 Monte Carlo forced-outage draws, consistent with a 0.1 LOLE (1-day-in-10-year) reliability target. We simulate both a 2025 portfolio and a 2030 portfolio based on E3's SPP outlook. Table 4 shows the eight different scenarios tested in RECAP.

Table 4: Scenarios Design in RECAP Performed for 2025 and 2030

Duration	Seasonal Call Limit	Penetration	Scenario Description
4 hours	40 hours/season	2 GW	Approximates the current level of DR adoption and duration
4 hours	40 hours/season	4 GW	Tests moderate DR growth and entry of new large loads
4 hours	40 hours/season	6 GW	Bookend scenario of high DR entry
4 hours	No Seasonal Call Limit	6 GW	Designed to understand the impact of adding more call hours with high saturation
10 hours	100 hours/season	2 GW	Approximates current levels of DR adoption and tests the value of longer duration
10 hours	100 hours/season	4 GW	Tests moderate DR growth and the value of longer duration
10 hours	100 hours/season	6 GW	Bookend scenario of high DR entry and duration
10 hours	No Seasonal Call Limit	6 GW	Designed to estimate the impact of adding more call hours under high DR saturation

Results

SPP Critical Hours in 2025 and 2030

Any resource's capacity accreditation, and thus ELCC, is determined by the alignment between SPP's timing of critical hours and resource performance. Understanding the baseline system's critical period is key to understanding incremental benefits of demand response.

During the Summer, critical hours are concentrated in July and August and are most pronounced between hours 12-17. These periods coincide with higher cooling demand, lower than expected thermal availability, and lower than expected wind generation, resulting in a 4-to-5-hour window of risk. In 2030, the summer loss-of-load hours widen and move later into the evening with higher adoption of solar. This creates an additional 3-to-4-hour window during and after sunset, an ideal scenario for energy limited resources like storage or demand response to be effective.

In the Winter, loss of load risk typically coincides with the most severe Winter days. Compared to Summer, the peak demand during the coldest days is typically much higher and longer, leading to an extended need for heating demand. Loss of load risk is therefore prevalent from the morning ramp-up until late in the evening. Cold snaps, wind droughts, and thermal forced outages pose a strong reliability risk for the entire Winter Day.

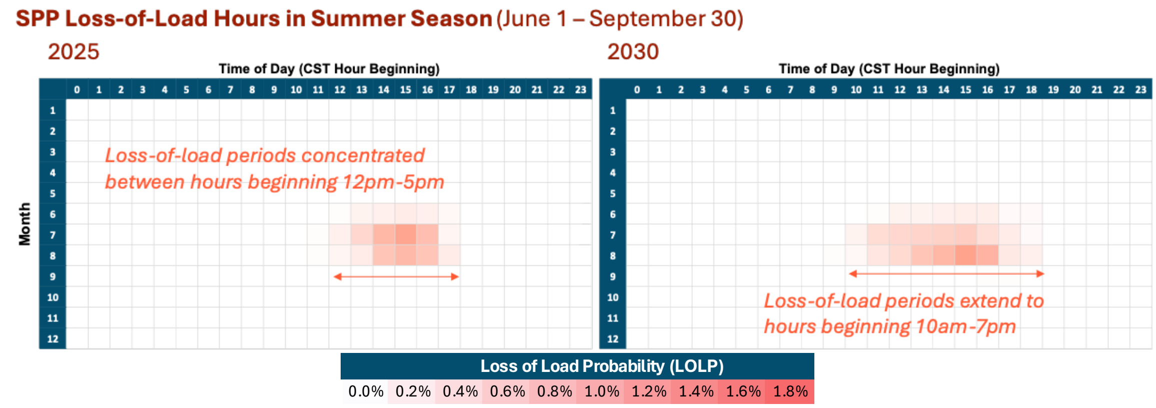

Figure 5: SPP Summer Loss of Load Patterns

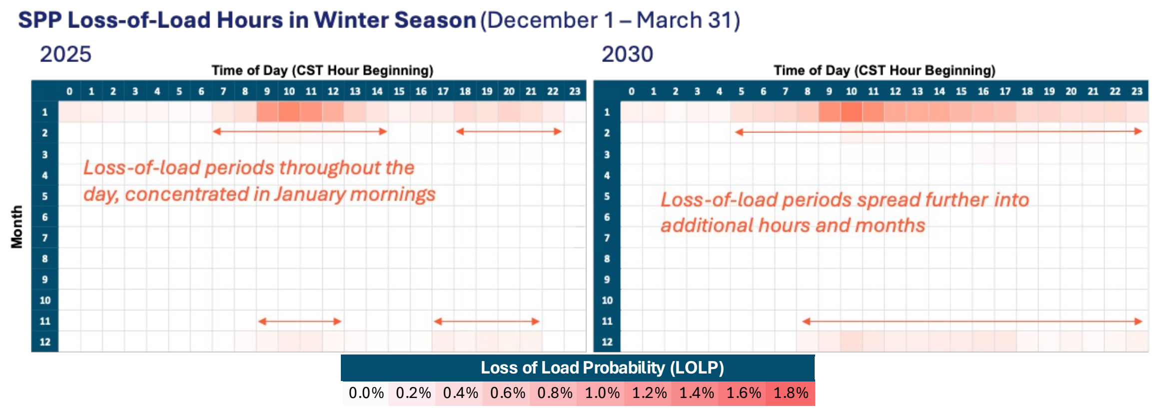

Figure 6: SPP Winter Loss of Load Patterns

2025 and 2030 DR ELCCs Results

To evaluate the reliability contribution of DR, we test multiple configurations that capture its operational limits and system interactions: duration, call limits, and penetration level. Four-hour DR has a Summer ELCC of 83% and 64% in 2025 and 2030 respectively, and a Winter ELCC of 55% and 36% in 2025 and 2030 respectively. Ten-hour DR achieves higher ELCCs than four-hour, 100% ELCC in the Summer for 2025 and 2030, and between 82% and 84% ELCC in the Winter from 2025-2030. These ELCC findings highlight the impact that duration has on capacity accreditation in the SPP. They also highlight the seasonal impact of accreditation as both four- and ten-hour DR perform well during concentrated summer afternoon risk windows, while ten-hour DR provides much more reliability benefits during multi-day cold snaps that drive extended loss-of-load conditions in the Winter.

Figure 7: 2025 and 2030 Summer and Winter ELCCs for Incremental 2GW 4-hr and 10-hr DR

Under high penetrations of DR, the ELCC results highlight saturation effects, and the impact of increasing call hours under high DR adoption. In 2030 with ten-hour duration, at 6GW of penetration, increasing the call limit increased capacity accreditation by 5%. With respect to the impact of saturation, four-hour DR saw stronger saturation effects than ten-hour. In 2025 four-hour ELCCs decline from 83% to 50% as penetration moves from 2GW-6GW. Ten-hour is more resilient to saturation effects and only declines by 11%.

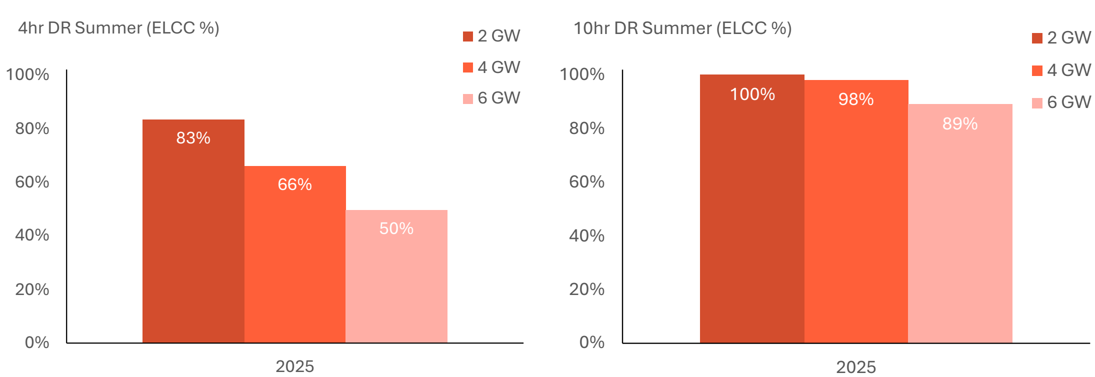

Figure 8: 2025 4-hr and 10-hr DR ELCCs across increasing penetrations between 2GW and 6GW

To achieve these ELCC results, DR requires only limited hours of response. Across the weather years and forced outage simulations in this study, an average of 10 hours of DR is required across the year to achieve the ELCCs described above. Further, under the most severe Winter event observed in the LOLP model, 72 hours are needed across the season to achieve an 82% ELCC for ten-hour DR. During the hottest Summer observed in the LOLP model, 83 hours are needed across the season to achieve 100% ELCC again on ten-hour duration DR. Figure 8 below highlights the max and average number of hours required across both study years for each duration tested for ten-hour DR.

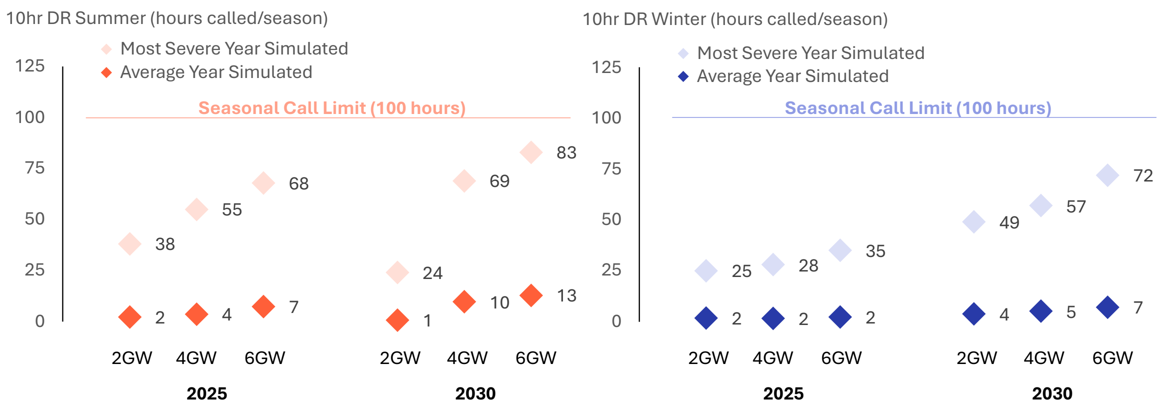

Figure 9: Hours of DR Program Dispatch Needed (Average vs Severe Weather Year)

Discussion and Conclusion

Using SPP's existing capacity accreditation construct, this study shows that DR's ELCC can range from 55% to 100 depending on the study year, season, and DR program characteristics. The results of the study from Figure 7 and Figure 8 reveal the following insights**:**

- Critical Hours: Across simulations in this study, SPP Summer exhibits critical hour periods lasting 3-5 hours whereas Winter critical hour periods often exceed 10 hours. DR has accordingly higher ELCCs in Summer than Winter.[5]
- Call Duration: Extending event lengths from four to ten hours increases ELCC materially, with the largest increase in capacity accreditation in the Winter.
- Call Limits: Increasing call limits increases ELCCs only under high penetrations of DR.
- DR Penetration: First 2 GW of DR yields high capacity accreditation, but with increasing DR penetration, saturation effects emerge.

Demand response can achieve similar accredited value to other utility-scale resources in SPP when evaluated under an ELCC framework. Figure 9 shows the achieved DR ELCCs measured in this study and the SPP capacity accreditation of multiple resource classes. In reality, DR is subject to potential non-response, which can reduce effective capacity during sequential or

[5] SPP Summer season is June 1 – September 30, Winter season is December 1 – March 31. Shoulder months do not have resource adequacy requirements in SPP.

prolonged stress events. The accreditation found in this study reflects DR's reliability contribution under the modeled call limits and assumes full participant response. Four-hour DR provides moderate capacity value but is vulnerable to saturation and winter duration risk. Ten-hour DR achieves accreditation comparable to eight-hour storage and thermal resources. Under constrained supply conditions and rising load growth, performance-accredited DR can function as a reliability bridge resource while long-term generation and transmission infrastructure develops. DR under these parameters can give system planners and operators another resource to meet near- and long-term resource adequacy needs.

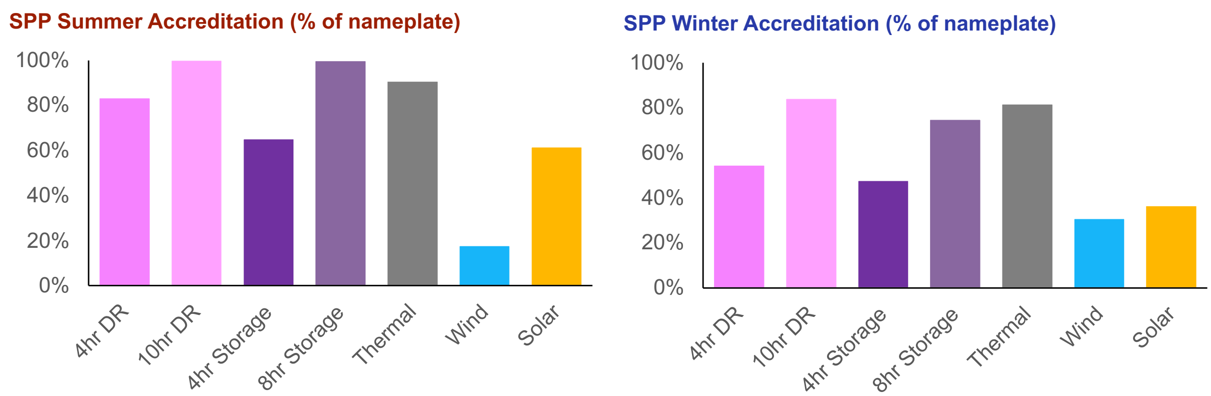

Figure 10: Summer and Winter Capacity Accreditation Comparison Between Study Results and Publicly Available SPP Results. Thermal Accredited Using ACAP and Wind and Solar ELCC.

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AI-assisted Tools

Disclosure

AI-assisted tools used: ChatGPT and Claude.
Used for: Outlining and Citation Format Accuracy
Extent: outline ideation, citation formatting
Human review: The authors reviewed and verified all content, calculations, and citations.