Reliability Filing Requirements for Load Serving Entities’ 2024-26 Integrated Resource Plans

- Results of Marginal ELCC Studies

February 2026

California Public Utilities Commission

Overview

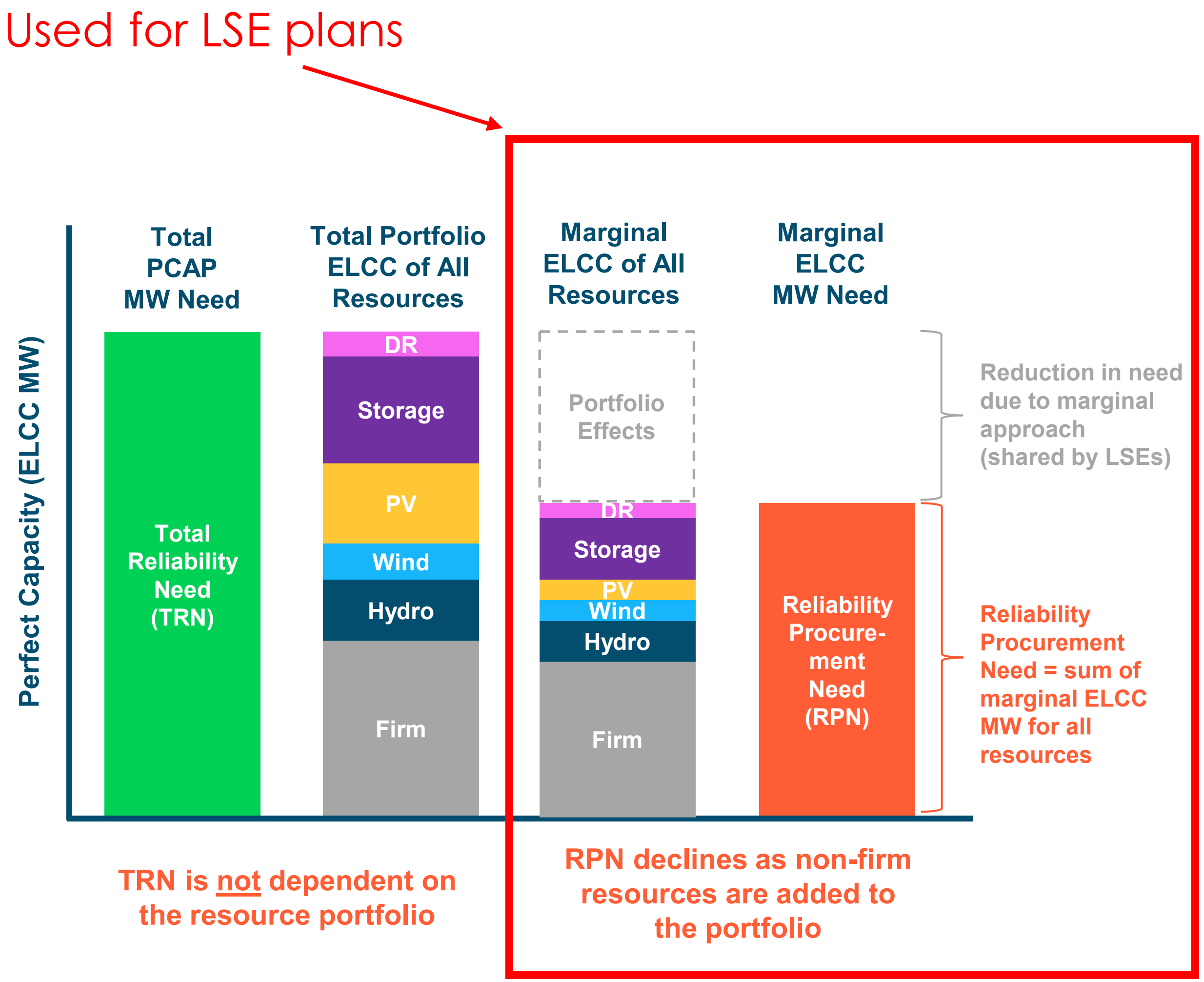
- **Purpose of these slides:**
  - Provide reliability inputs* to be used in LSE plans for the 2024-26 IRP cycle
  - Promote stakeholder understanding of how the reliability inputs were developed for the 2024-26 IRP cycle
- **Key updates since 2022-23 IRP Cycle:**
  - *Note: System-level reliability modeling in the 2024-26 IRP Cycle uses the same methodology as the 2022-23 IRP Cycle.*
  - Update inputs and assumptions, including 2024 IEPR load forecast, new least cost portfolio, and resource outage rates.
  - Refresh Marginal ELCC study results for 2026-2045.
  - Calculate CAISO Reliability Procurement Need** (RPN) values for 2026-2045 and update allocation of RPN to LSEs.
    - Allocation of RPN to LSEs in 2024-26 IRP Cycle is based on load share during critical hours instead of managed peak share.

*"Reliability inputs" refers reliability *planning* inputs, not to those used in IRP procurement
**Formerly known as "Marginal Reliability Need" in 2022-23 IRP Cycle

Key Reliability Inputs for LSEs’ 2024-26 Integrated Resource Plans

Key Reliability Inputs for LSE Plans under the Marginal ELCC Framework

- The following reliability inputs are developed by staff to be used for LSE planning in the 2024-26 IRP cycle:
  1. **Resource Marginal ELCCs**: Marginal ELCCs for different resource classes with a given system portfolio
     - Captures resource contributions during critical reliability hours
  2. **Reliability Procurement Need (RPN):** System-level reliability need
     - RPN is calculated as the sum of marginal ELCC MW for all resources in the portfolio
  3. **Need Allocation**: Allocate RPN to LSEs based on LSE load share during critical hours
     - Use 2026 year-ahead RA SOD forecast for LSE hourly loads
     - Weighted based on critical hour frequency (i.e., occurrence of EUE during a particular month-hour)



Resource ELCCs are determined by the system portfolio; staff use the 2025 LSE Filing Requirements portfolio to develop marginal ELCCs for LSEs to use in their plans for the 2024-26 IRP cycle.

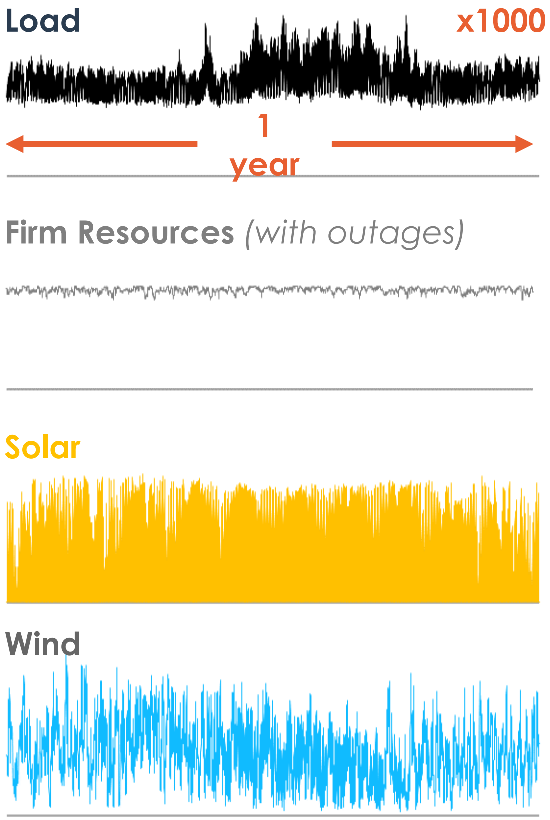
Reliability Modeling in IRP

Background and Context

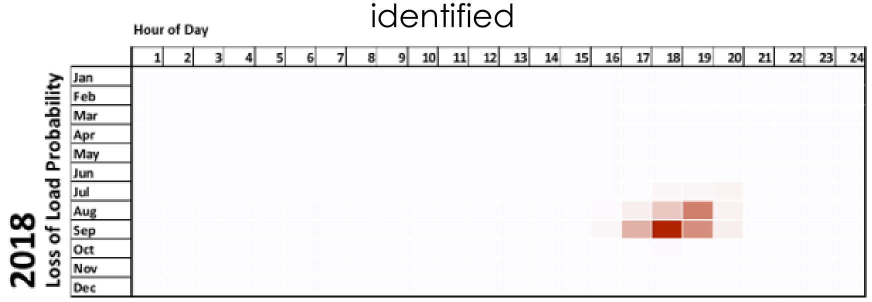
Loss of Load Probability (LOLP) Modeling

- Loss of load probability (LOLP) modeling is a probabilistic method to consider system reliability across a wide range of load and weather conditions
    - LOLP model inputs are tuned to historical correlations between weather, load, and renewable output
    - Monte Carlo simulations consider system operations across a range of weather conditions
- The CPUC IRP uses PowerGEM's stochastic reliability model SERVM, which considers the following:
    - 23 years of historical weather conditions (2000-2022) to inform load, wind, solar, and hydro output
    - Economic-related load forecast uncertainty
    - Random unit-level forced outage draws
    - Regional market interactions

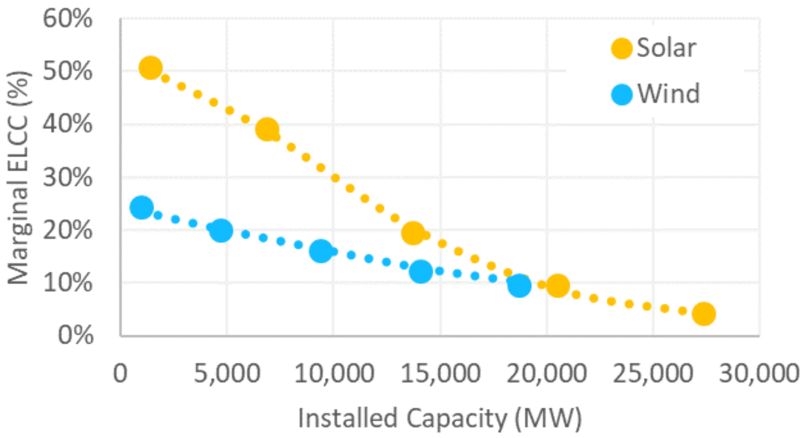
Monte Carlo simulation of loads, renewable profiles, and generator outages used to simulate many years of plausible system conditions



System reliability measured relative to "one day in ten year" standard; periods of high loss of load probability identified



Effective load carrying capability (ELCC) for a wide range of types of resources evaluated



Example RECAP result from *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* (Calpine, 2019)

LOLP Analysis Produces a Range of Useful Metrics

- <u>Statistical reliability metrics:</u> measures of the size, duration, and frequency of reliability events

Result	Units	Definition
Expected Unserved Energy (EUE)	MWh/year	Average total quantity of unserved energy (MWh) over a year due to system demand plus reserves exceeding available generating capacity
Loss of Load Probability (LOLP)	%	Probability of system demand plus reserves exceeding availability generating capacity during a given time period
Loss of Load Hours (LOLH)	hours/year	Average number of hours per year with loss of load due to system demand plus reserves exceeding available generating capacity
Loss of Load Expectation (LOLE)	days/year	Average number of days per year in which unserved energy occurs due to system demand plus reserves exceeding available generating capacity
Loss of Load Events (LOLEV)	events/years	Average number of loss of load events per year, of any duration or magnitude, due to system demand plus reserves exceeding available generating capacity
Total Reliability Need (TRN)	ELCC MW (or accredited MW)	Total capacity MW necessary to maintain an adopted reliability standard (e.g. < 0.1 day/yr LOLE). Can be in effective MW (i.e. ELCC or perfect capacity equivalent) or defined relative to existing RA accounting (e.g. ICAP).

- <u>Derivative metrics:</u> additional useful measurements that can be derived from LOLP analysis

Result	Units	Definition
Planning Reserve Margin Requirement (PRM)	% 1-in-2 peak load	The planning reserve margin needed to achieve a given reliability metric (e.g., 1-day-in-10-years LOLE)
Effective Load-Carrying Capability (ELCC)	MW	Effective "perfect" capacity provided by variable or energy-limited resources such as hydro, renewables, storage, and demand response
Residual Capacity Need	MW	Additional "perfect" capacity needed to achieve a given reliability metric

Five Studies Used for IRP and LSE Reliability Planning

1. **[System-level Planning]** Determine Total Reliability Need (TRN) based on quantity of equivalent perfect capacity needed to meet the specified reliability standard (0.1 days/yr LOLE) by calibrating the LOLP model of the power system.

2. **[System-level Planning]** Determine the Optimal Portfolio in RESOLVE capacity expansion, using LOLP-derived ELCC curves and surfaces to measure the reliability of the portfolio, ensuring it meets (or exceeds) the total reliability need.

Use Case:
- **RESOLVE long-term system optimization to determine the system portfolio used to develop LSE filing requirements**

Not portfolio dependent

focus of this presentation

3. **[LSE Plan Inputs]** Forecast Marginal ELCCs of individual resource types in a fixed long-term portfolio, based on their marginal contribution toward the TRN, or equivalently their expected performance during Critical Periods.

4. **[LSE Plan Inputs]** Forecast Reliability Procurement Need (RPN) as the sum of Marginal ELCCs of individual resources in a "tuned" portfolio, functionally aligned with expected load + operating reserves served during Critical Periods.

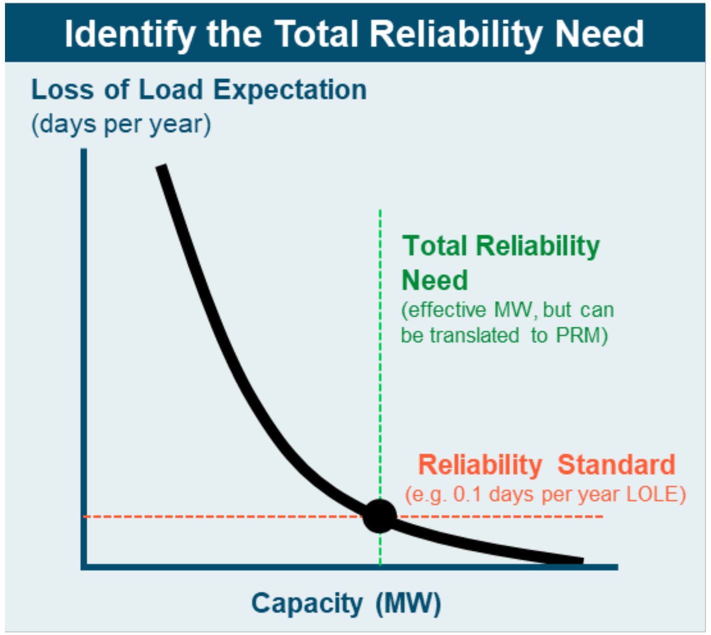
5. **[LSE Plan Inputs]** Allocate RPN to Load-Serving Entities based on their expected contribution to the marginal need for capacity, i.e., their expected load during Critical Periods.

Use Case:
- **Inputs LSE can use to develop their plans**

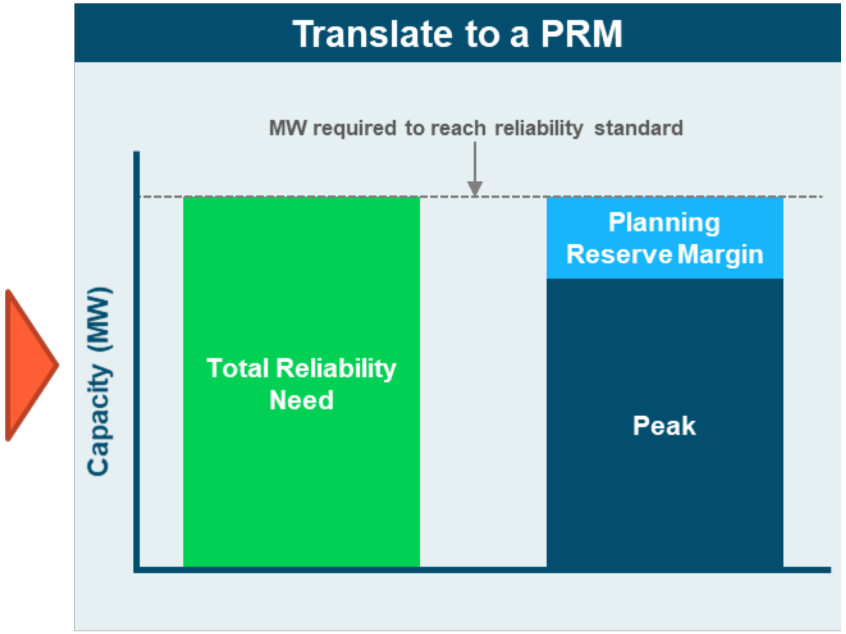
Portfolio dependent

Using the Total Reliability Need (TRN) to Derive the PRM

- The Planning Reserve Margin (PRM) is a derivative value from the Total Reliability Need (TRN)
    - TRN is a MW value output from LOLP modeling
- The TRN/PRM can be defined using multiple approaches
    - e.g. resource accreditation methods (e.g. PCAP versus ICAP)



Total Reliability Need =
Total capacity MW necessary to maintain an adopted reliability standard (e.g. < 0.1 day/yr LOLE).

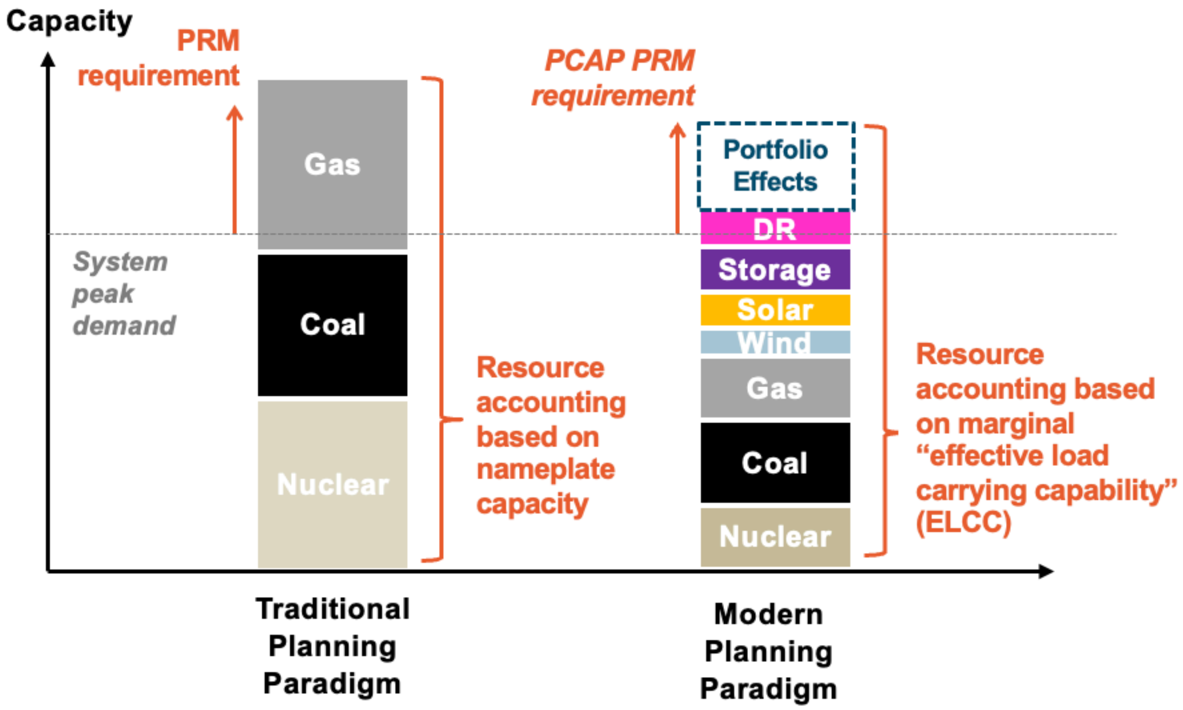


Planning Reserve Margin =
% margin above peak demand necessary to reach the TRN

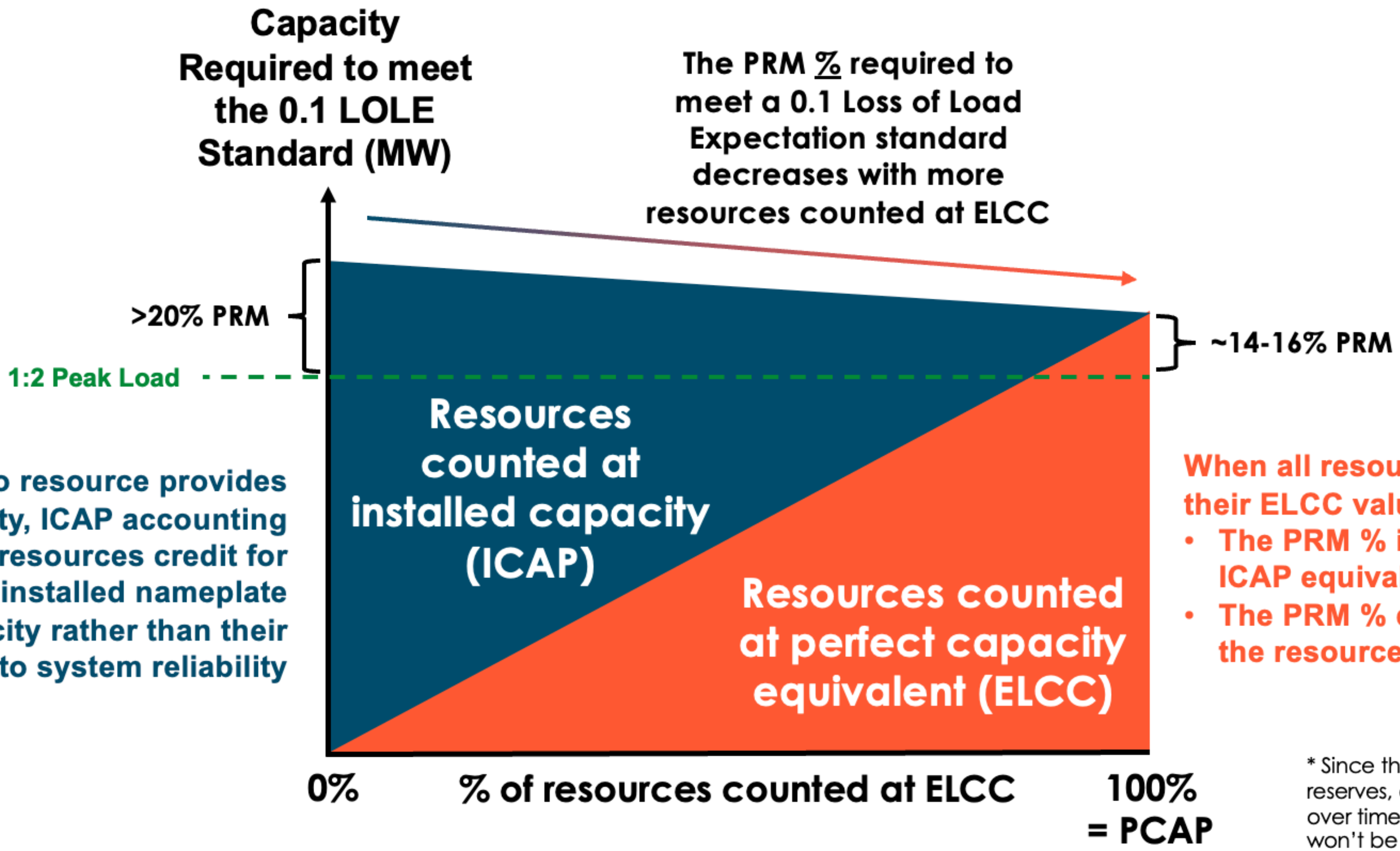
$$PRM\ \% = \left(\frac{TRN}{Peak\ Demand}\right) - 1$$

Using a Perfect Capacity (PCAP) PRM

- PRM defined based on need for Perfect Capacity (PCAP)
  - Covers annual peak load variation and operating reserves only; forced outages addressed in resource accreditation
  - Staff shifted from Installed Capacity (ICAP) accounting to PCAP accounting in the 2022-23 IRP cycle
- Individual resources accredited based on ELCC
  - Large differences in availability during peak
  - Significant interactions among resources
  - ELCC values are dynamic based on resource mix



PCAP PRM Provides a More Durable Definition of Total Reliability Need



Even though no resource provides perfect capacity, ICAP accounting gives “firm” resources credit for their full installed nameplate capacity rather than their contribution to system reliability

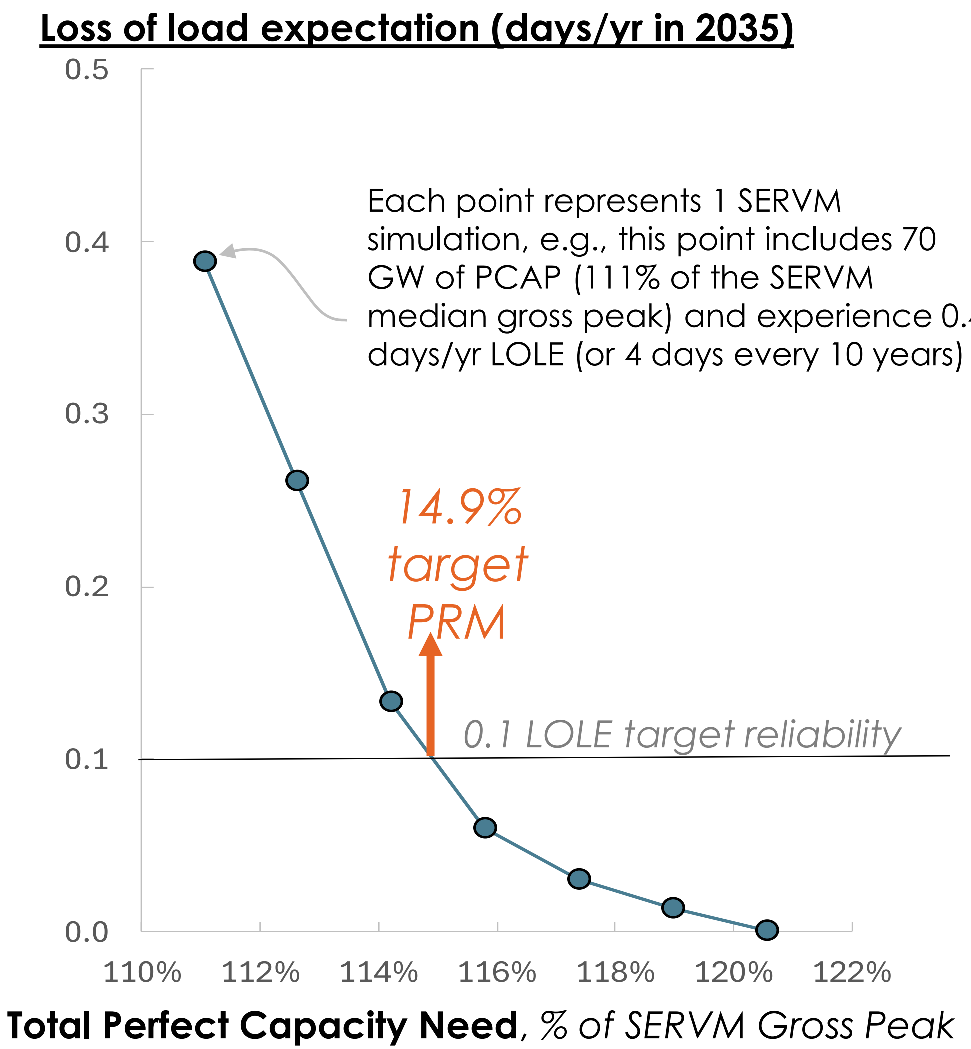
When all resources are counted at their ELCC value:

- The PRM % is lower than its ICAP equivalent
- The PRM % does not change as the resource portfolio evolves*

* Since the PCAP PRM % is a function of operating reserves, and load variability, the % may change over time if these inputs change but the percentage won't be dependent on the resource portfolio.

Setting the TRN and PCAP PRM for RESOLVE

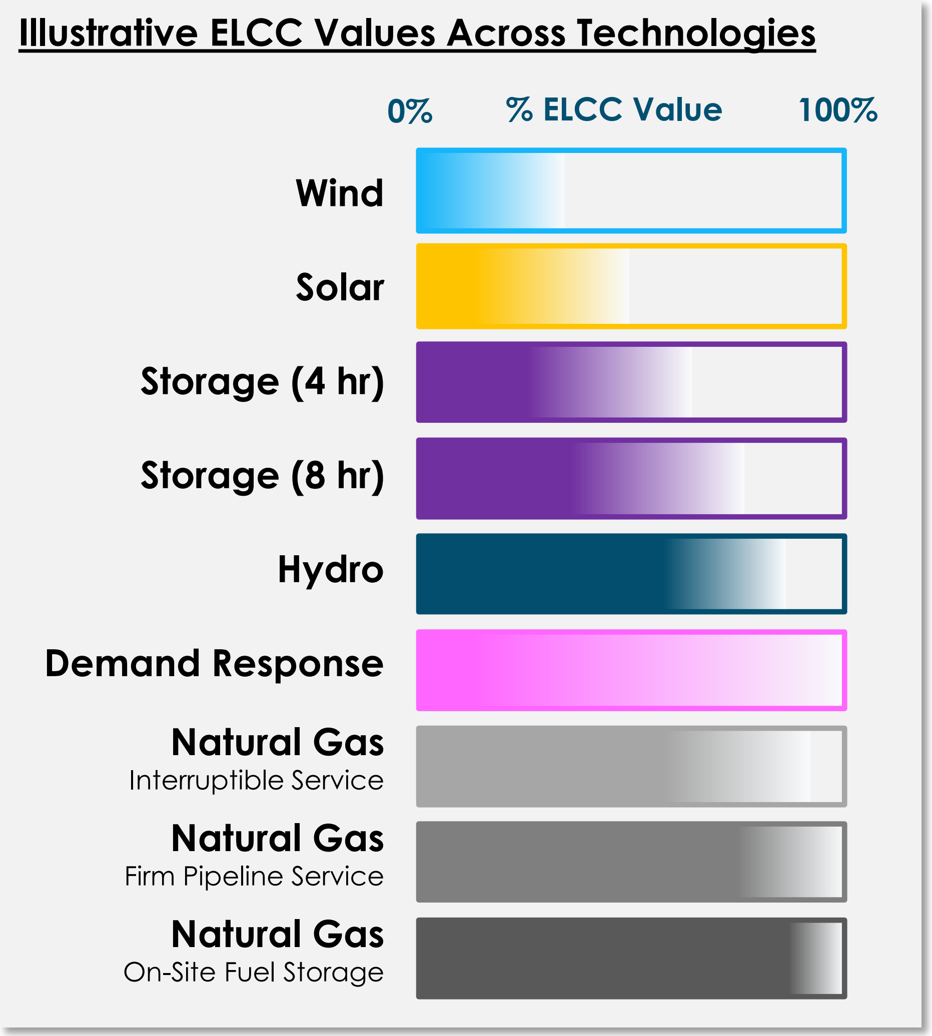
- The target PRM is calculated using the SERVM LOLP model for multiple years in the planning horizon
- The PCAP PRM is measured relative to gross peak (managed peak + BTM PV)
  - BTM PV forecast comes from IEPR
- The Total Reliability Need (TRN) RESOLVE must build to is the gross peak + PRM



No Resource is "Perfect"

Marginal ELCC creates a level playing field by measuring all resources against perfect capacity

- Can account for all factors that can limit availability:
  - Hourly variability in output
  - Duration and/or use limitations
  - Seasonal temperature derates
  - Energy availability
  - Fuel availability
  - Temperature-related outage rates
  - Correlated outage risk
- While ELCCs are a % of nameplate capacity, their calculation in SERVM includes both capacity and energy constraints.



Calculating ELCCs Through LOLP Modeling

- **Effective Load Carrying Capability (ELCC) represents the equivalent "perfect" capacity that a resource provides** in helping to achieve the target reliability metric (e.g., 0.1 day/year LOLE), e.g. a 100 MW resource with an ELCC of 30% is equivalent of 30 MW perfect capacity
  - Derived from LOLP modeling, building on foundation for resource adequacy analysis
  - Captures complex interactive/portfolio effects, e.g., saturation and diversity benefits
  - Agnostic to technology and can be applied to all resources

1 → 2 → 3

1 Calculate existing system reliability and tune the system to the target

2 Add desired resource to portfolio

Addition of new source of generation will increase reliability relative to measurement in Step 1

3 Remove perfect capacity until target reliability is restored

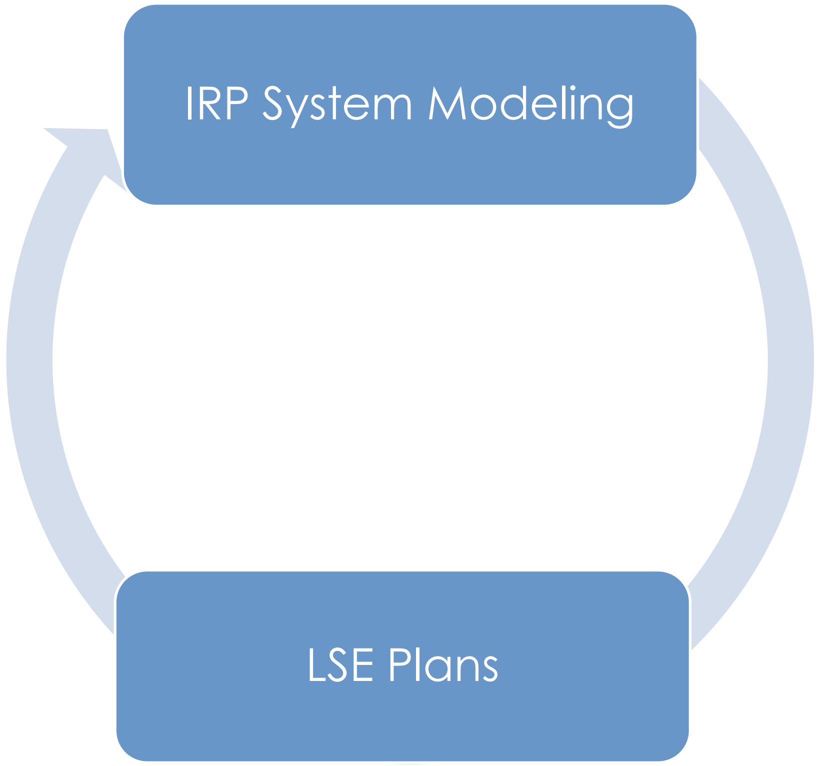
Removal of perfect capacity results in decrease in reliability until original target is met

A resource's ELCC is equal to the amount of perfect capacity removed from the system in Step 3

Using System-level Modeling Results to Determine LSE Plan Inputs

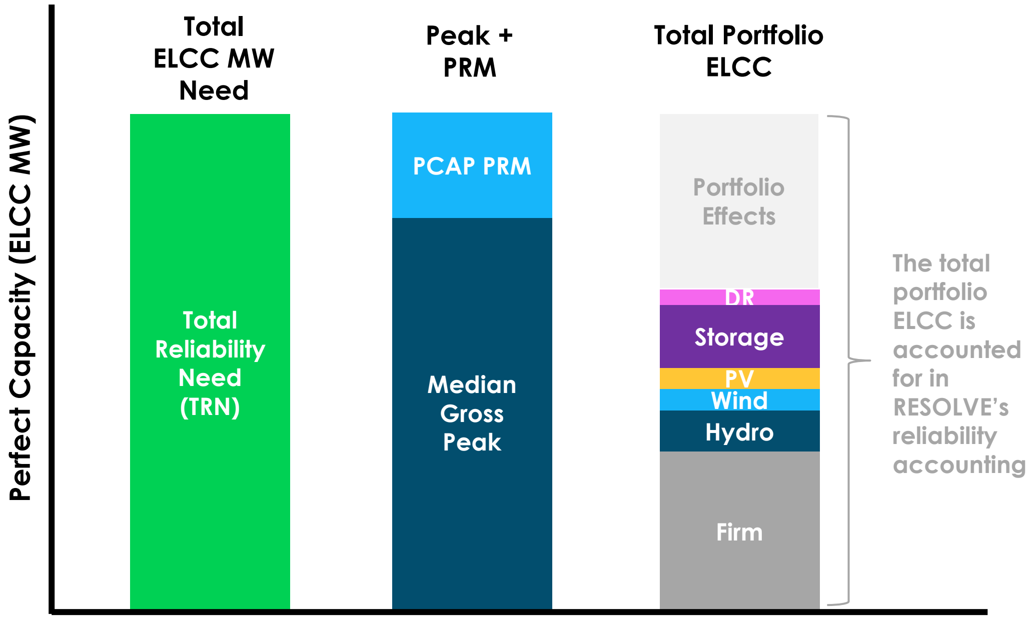
- System-level modeling performed by IRP staff produces the system portfolio to be used to develop LSE plan inputs

- The "**filing requirements portfolio**" is modeled in SERVM to calculate the **marginal ELCCs for different resource classes, the reliability procurement need, and the allocation of the procurement need to LSEs**
  - LSE plans should meet their allocated reliability need using the marginal ELCCs produced in these studies



Different Accounting Frameworks for IRP system planning and LSE planning

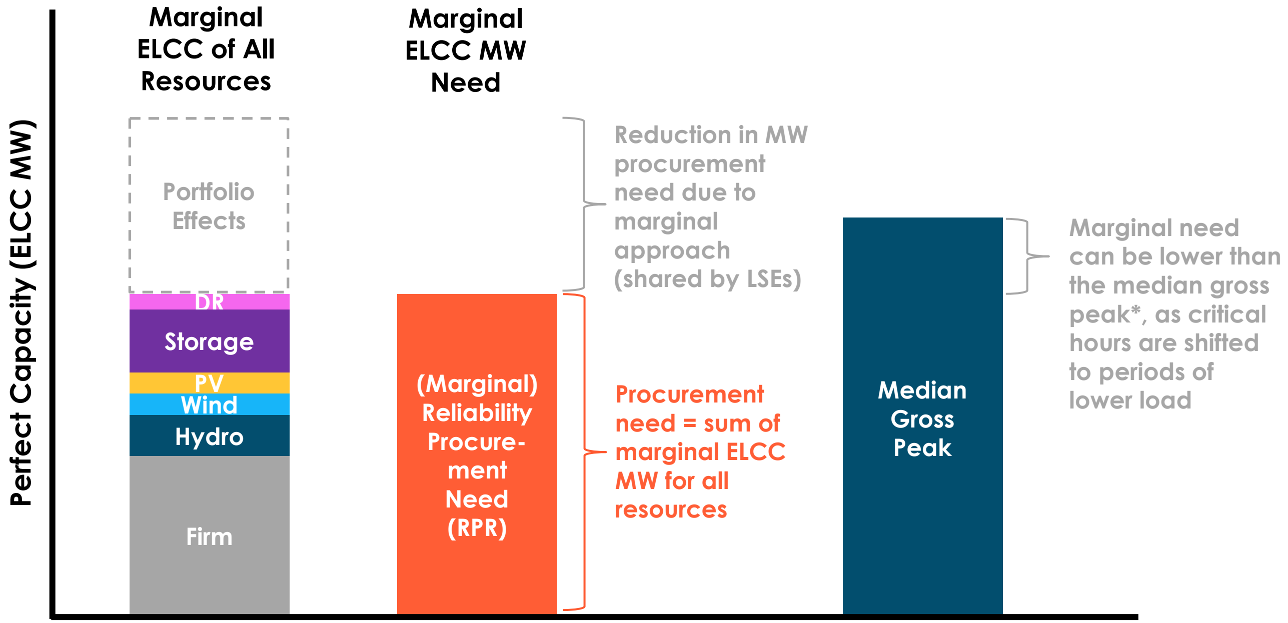
IRP Planning (RESOLVE): Total Reliability Accounting



For IRP long-term planning, total reliability accounting is used, based on the TRN and PRM used in RESOLVE.

- RESOLVE ensures the total portfolio ELCC need is met in each year.
- RESOLVE's ELCC surfaces/curves indicate the marginal value of additions to support least-cost optimization and capture portfolio effects.

LSE Planning + Procurement: Critical Periods Accounting



For LSE plan development, marginal reliability accounting is used, based on the (marginal) reliability procurement need (RPN).

- Marginal accounting ensures efficient market entry/exit signals to the dozens of LSEs that are part of the broader CAISO market.
- Since need is calculated directly via the sum of marginal ELCCs, there is no need to calculate a PRM.

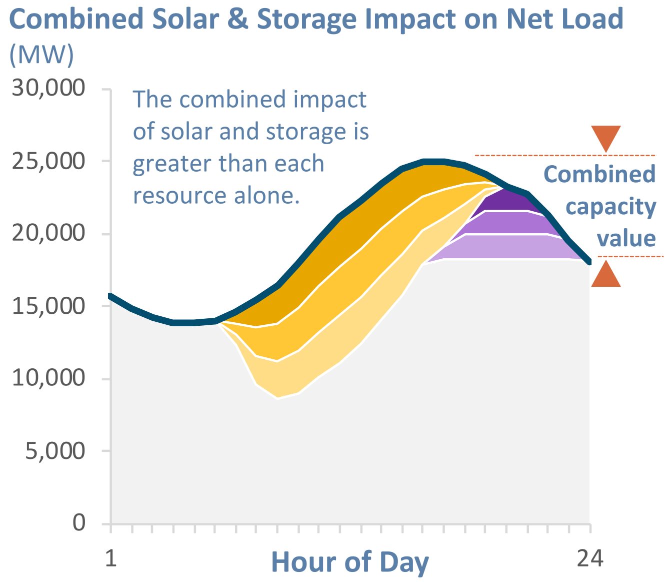
* If measuring marginal need (during critical hours) relative to median gross peak, this would imply a negative PRM. This PRM would change as portfolio changes shift the critical hours relative to the median peak. A PRM is unnecessary in this framework since the sum of marginal ELCCs directly denotes the need.

"Portfolio effects" include saturation and interactive effects

Saturation: Diminishing marginal value when adding variable resources (e.g., solar, wind) and energy-limited resources (e.g., storage, demand response, hydro).

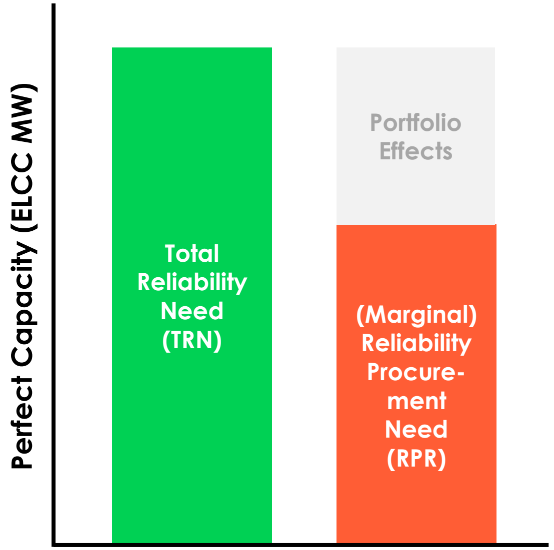
Interactive Effects, including…

a) Diversity Benefits (Synergistic Interactive Effects): A portfolio of different resources exhibit complex interactive effects, where the whole may exceed the sum of its parts (e.g., solar and storage).



b) Antagonistic Interactive Effects: Some resources provide similar types of value (e.g., storage and DR) and compete with each other.

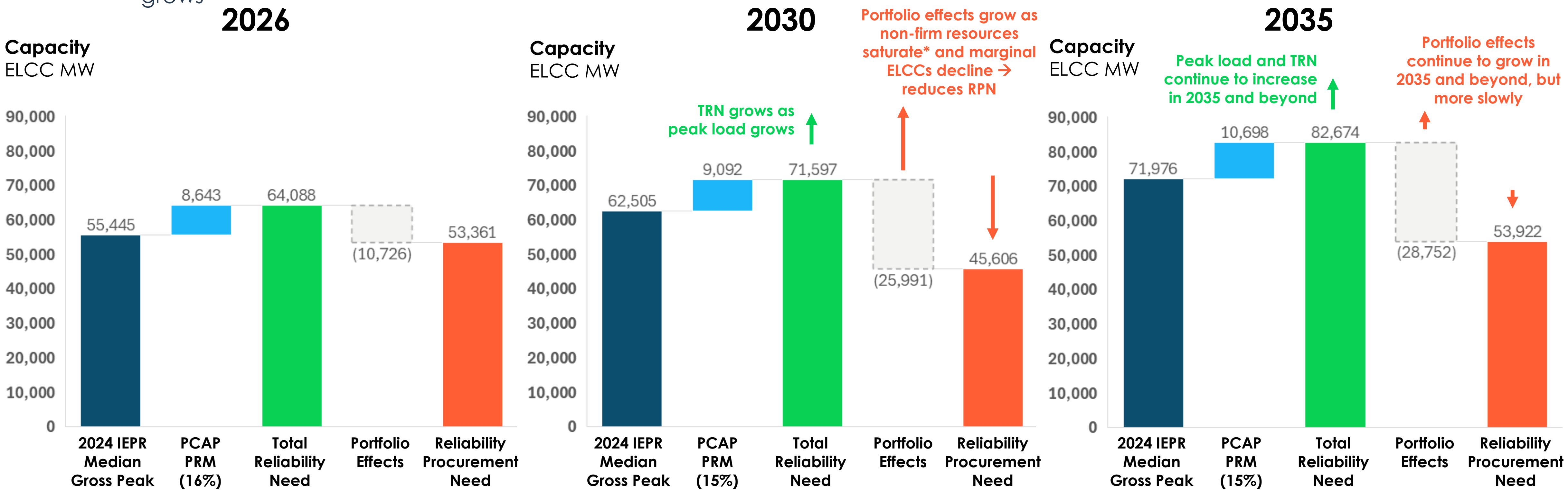
Portfolio Effects: Considering both saturation and interactive effects, marginal ELCCs are lower than the total portfolio ELCC.



For more details on interactive effects, see E3's critical periods reliability framework whitepaper.

Total Reliability Need versus Reliability Procurement Need will change as the resource portfolio evolves

- Reliability Procurement Need (RPN) is **portfolio-dependent** and will change as portfolio and marginal ELCCs evolve
- As more variable and energy-limited resources are added, their marginal ELCCs decrease due to portfolio effects, especially **saturation**
    - This makes the sum of the marginal ELCCs lower relative to the total portfolio ELCC as clean energy and storage penetration grows



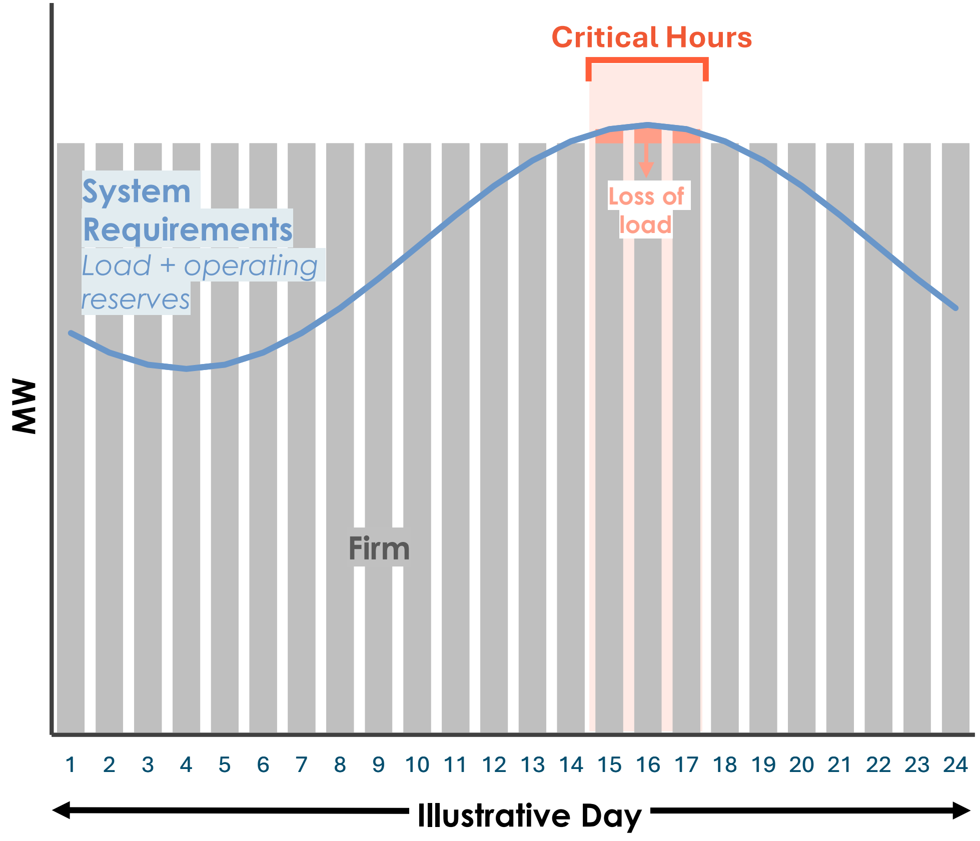
**Near-term increase in saturation driven by over-build for meeting 2030 GHG target*

Defining Critical Hours for Marginal ELCC Approach

- **What are critical hours?** Hours in which an additional resource MWh will reduce unserved energy.
- **How is this different than loss-of-load hours?** Critical hours include loss of load hours. In cases where a loss-of-load event occurs once storage energy is exhausted, the critical hours also include hours of storage discharge*.
- **How to estimate them?** Using SERVM simulations, for loss of load events where storage MWhs are exhausted, critical hours include the hours prior to the loss of load event in which storage was discharging.
- **Uses of critical hours?** Critical hours are used to allocate the reliability procurement need (RPN) to LSEs for IRP filing requirements and resource output during critical hours is indicative of marginal ELCC values.

*In systems that have energy charging sufficiency constraints for storage, critical hours can also include hours of storage *charge*

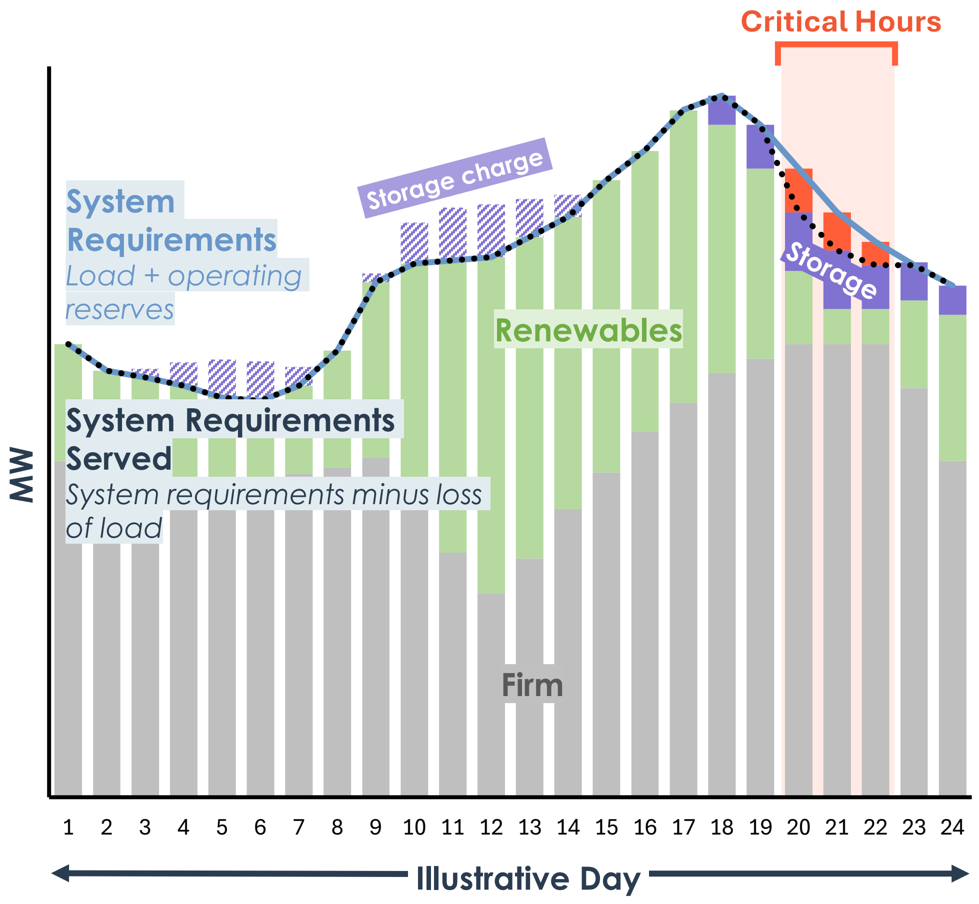
Setting Reliability Need in Traditional Reliability Planning



- **Need determination reflected total resource need to meet target reliability**
  - Functionally equivalent to gross load plus operating reserves minus loss of load deemed acceptable during LOLP hours
  - Contextualizing this value relative to the 1-in-2 median annual peak yielded a % planning reserve margin
- **Resource counting was based on nameplate capacity**
  - Because most resources were firm, this was functionally equivalent to availability during LOLP hours

LSE Plan Inputs

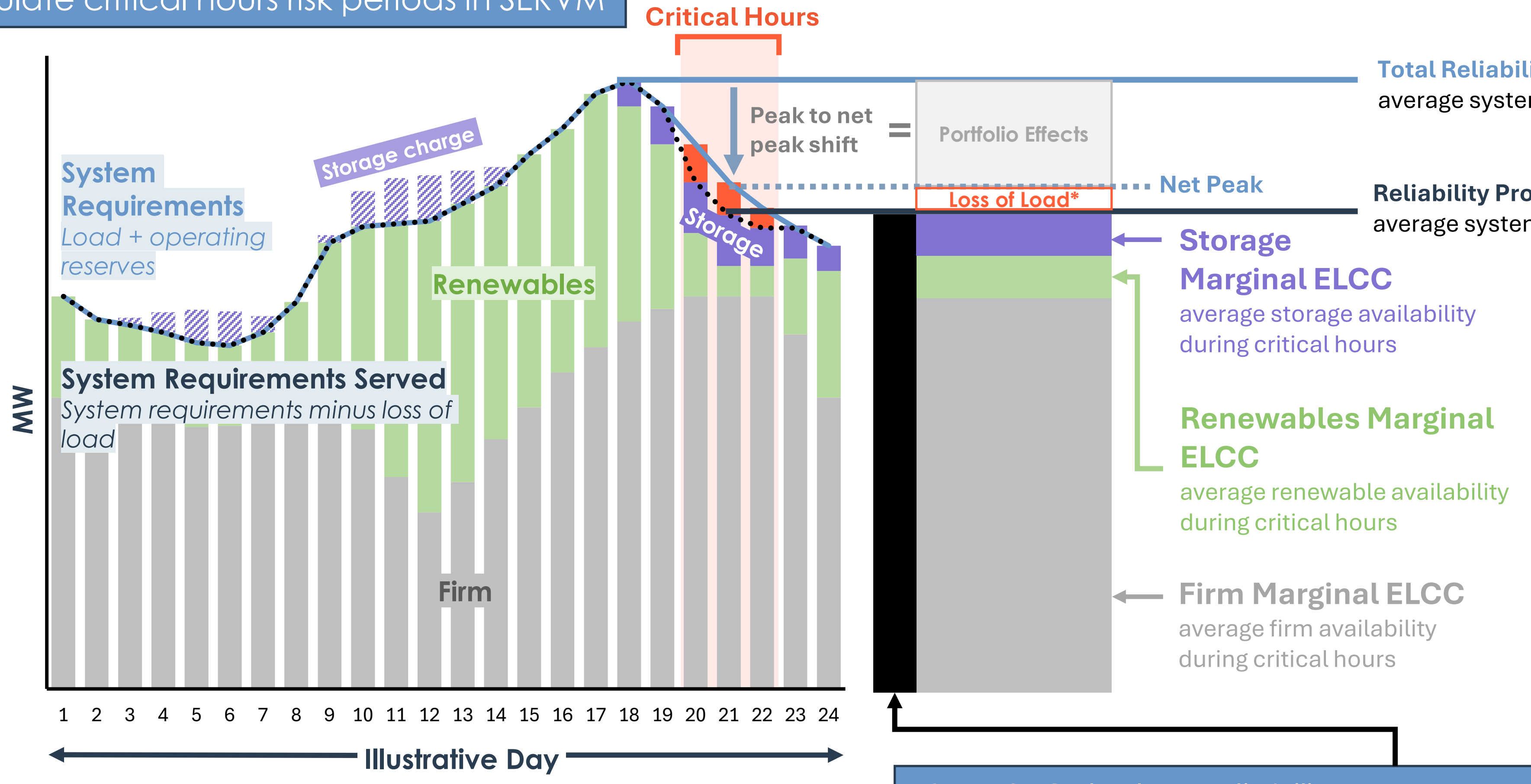
Critical Periods Based Reliability Planning



- **As the system evolves, loss of load risk will shift away from the gross peak to the net peak.**
  - LOLP modeling considers all hours of the year and – based on the portfolio modeled – identifies the new critical periods with reliability risk
  - For a system with a large share of non-firm resources (renewables, storage, DR), ensuring reliability during the gross peak no longer ensures reliability during the net peak
- **LSE planning should focus on the critical reliability risk periods, consistent with past practices for reliability planning.**
  - Resource counting based on ability to reduce loss of load risk (via marginal ELCC)
    - Marginal values provide an accurate investment signal for market entry/exit
  - Need set based on sum of marginally accredited capacity for a system at 0.1 days/yr LOLE, functionally equivalent to the gross load + operating reserves during hours with loss of load risk

Setting Reliability Need Based on Critical Periods

Step 1: Using forecasted resource portfolio, calculate critical hours risk periods in SERVM



Step 2: Calculate resource marginal ELCCs during critical hours risk periods based on how resource meets the need

Step 3: Calculate reliability procurement need as the sum of marginally accredited MW for a system at 0.1 days/yr LOLE

For more details, see E3's critical periods reliability framework whitepaper.

* Loss of load represents the small amount of lost load allowed under the CPUC's 1-day-in-10-year LOLE standard. Not shown to scale.

Marginal ELCC Study Results

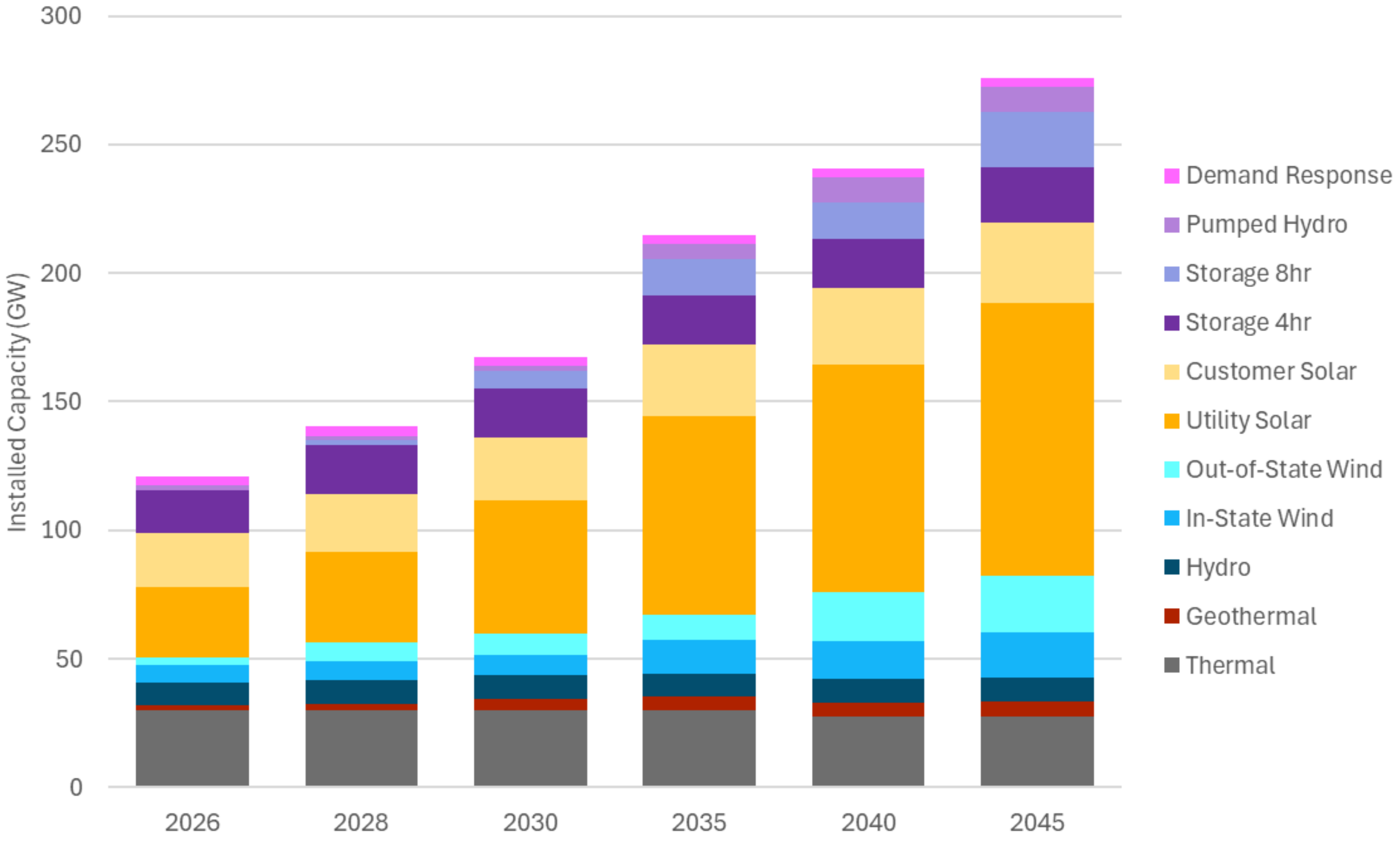
Marginal ELCC Modeling Overview

Key steps for the marginal ELCC Analysis include:

1. **Calibrate least-cost filing requirements (FR) portfolio** to 0.1 LOLE in SERVM
   - This step is needed considering the FR portfolio is over-reliable for multiple years due to builds driven by GHG emission reduction beyond RA needs
   - The calibration was performed by adding or removing perfect capacity resources until 0.1 LOLE is achieved
   - Neighboring regions were calibrated first, followed by CAISO
2. **Calculate marginal ELCCs** for each resource class
   - **20 classes modeled**: Utility PV, BTM PV, in-state wind (NorCal, SoCal), out-of-state wind (WY, ID/WA/OR, AZ/NM), offshore wind (NorCal, SoCal), small hydro, large hydro, pumped hydro, storage (4-hr, 8-hr, 12-hr, 24-hr, 100-hr), geothermal, DR, firm resources
   - **Years run**: 2026, 2028, 2030, 2035, 2040, 2045
3. **Calculate LSE plan inputs** by post-processing results as needed
   - Calculate marginal ELCCs for thermal subclasses using forced outage rates
   - Adjust basis for hydro and DR marginal ELCCs
   - Linearly interpolate between modeled years

CAISO Portfolio for Marginal ELCC Studies

- The least-cost filing requirements portfolio was developed using the following basic assumptions, as described in the 2025 inputs and assumptions:
  - 2024 NREL ATB + IRA
  - Latest CEC Land Use Screens for resource potential
  - Transmission constraint data from CAISO
  - Statewide GHG targets (30 MMT by 2030, 25 MMT by 2035, 8 MMT by 2045)
  - No new gas capacity

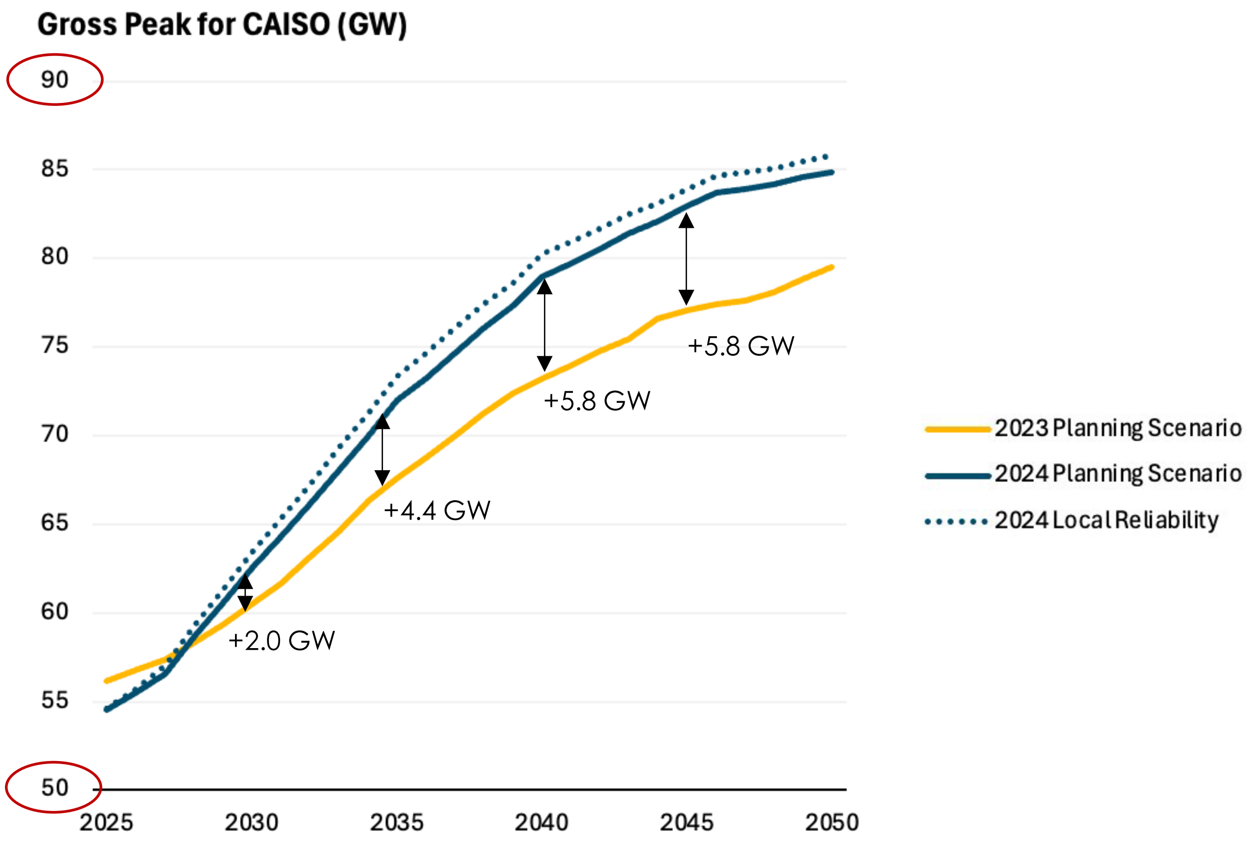


Portfolio shown in the chart reflects FR portfolio before calibration to 0.1 LOLE.

Key Assumptions

Load Forecast

- Staff used the 2024 IEPR Planning Scenario load forecast
- CAISO gross peak (sales + losses + BTM PV impact) rises from ~55 GW in 2025 to ~85 GW in 2050 in the 2024 IEPR
  - This is a significant increase compared to previous forecasts
- Primary drivers of increased load are data centers, electric vehicles, building electrification (including new space cooling adoption)
  - These outpace load reductions from additional BTM PV and energy efficiency



Key Assumptions

Forced Outages and Thermal Maintenance

- **Forced Outages:** For all study years, equivalent forced outage rates (EFOR) were assumed for storage resources and thermal resources, including tiered rates for gas CC and CT resources
- **Maintenance Rates:**
  - Today, thermal maintenance are typically scheduled for winter and shoulder months
  - Staff expects that thermal maintenance rate during winter will be adjusted as the system reliability risk shifts more to winter in the long term
  - ELCC studies assumed maintenance rates using current practices for 2026-2030 and assumed no winter maintenance for 2035-2045*

*Staff performed marginal ELCC modeling assuming 0 winter maintenance in 2040-2045 as current winter maintenance would have distorted ELCCs (e.g., gas plants on maintenance outages would have much lower ELCCs when risks shift to winter). The latest CPUC SERVM client now assumes reduced (but non-zero) winter maintenance rate, which is reflected in the calculation of RPN so that the need reflects the current SERVM assumptions when testing LSE plans during PSP aggregation.

Sample of Storage EFOR

	2030
Storage 4-hr	3.5%
Storage 8-hr	3.2%
Pumped Storage	1.1%

Tiered Thermal EFOR

	Low	Mid	High
Non-Summer CC	2.2%	7.6%	17.4%
Non-Summer CT	9.9%	20.8%	25.0%
Summer CC	1.3%	3.1%	8.6%
Summer CT	4.4%	20.0%	25.0%

Step 1 – Calibrate CAISO and Neighboring Regions

1. **Calibrating Neighboring BAAs:** Calibrated all neighboring balancing authorities to 0.1 days/year LOLE* by adding or removing perfect capacity (PCAP).
2. **Calibrating CAISO BAA:** Calibrated the CAISO system to 0.1 LOLE* by retiring thermal (firm) resources and adding back PCAP**.
   - Calibration Adjustment = PCAP Added – (Thermal Capacity Retired **x** Thermal Marginal ELCC)

Calibration Adjustment***

2028-2035 are over-reliable due to GHG targets driving RA over-build.
2040-2045 reliability is sensitive to the winter maintenance levels assumed.

units = ELCC MW	2026	2028	2030	2035	2040	2045
Calibration Adjustment	(160)	(2,665)	(5,997)	(7,532)	(5,924)	(8,936)

*Probability weighted average LOLE across all weather years and load forecast errors.
** PCAP was added back in to enable PCAP tuning during marginal ELCC runs.
***Staff performed marginal ELCC modeling using these calibration results. Additional calibration runs with different assumptions were performed for the RPN calculation. Staff expects the update will have limited impacts on marginal ELCCs and did not update the marginal ELCC modeling.

Key Modeling Steps

Step 2 – Calculate Resource Marginal ELCCs

1. **Added Resource ICAP:** Added an incremental amount of installed capacity (ICAP) for the resource class being tested.

2. **Removed PCAP Until 0.1 LOLE was reached:** Removed perfect capacity from the system until LOLE increased back to 0.1 days/yr.

3. **Calculated Marginal ELCCs:**

$$\mathrm{mELCC} = \frac{PCAP\ MW\ removed}{Resource\ ICAP\ added} \times 100\%$$

Step 3 – Post-Process Marginal ELCCs

- **Thermal subclasses:** SERVM produced ELCC values for thermal resources in aggregate. ELCC values for thermal subclasses were calculated such that the ELCC derate relative to the aggregate thermal ELCC was proportional to the equivalent forced outage rate (EFOR); see Appendix for subclass ELCCs.
  - Used this relationship: $\frac{EFOR_{subclass}}{EFOR_{class}} = \frac{1 - mELCC_{subclass}}{1 - mELCC_{class}}$
- **Hydro/DR adjustments:** ELCCs from SERVM were adjusted to align with the MW values to be used by LSEs in the RDT.
  - **Hydro:** Scale ELCC to use Sept NQC as the denominator (instead of historical fleetwide average production, which is the assumption used in SERVM)
  - **DR:** Scale ELCC to use nameplate as the denominator (instead of monthly CapMax, which is the assumption used in SERVM)
- **Non-modeled years:** Linearly interpolated between modeled years.

Modeling Results

Marginal ELCCs

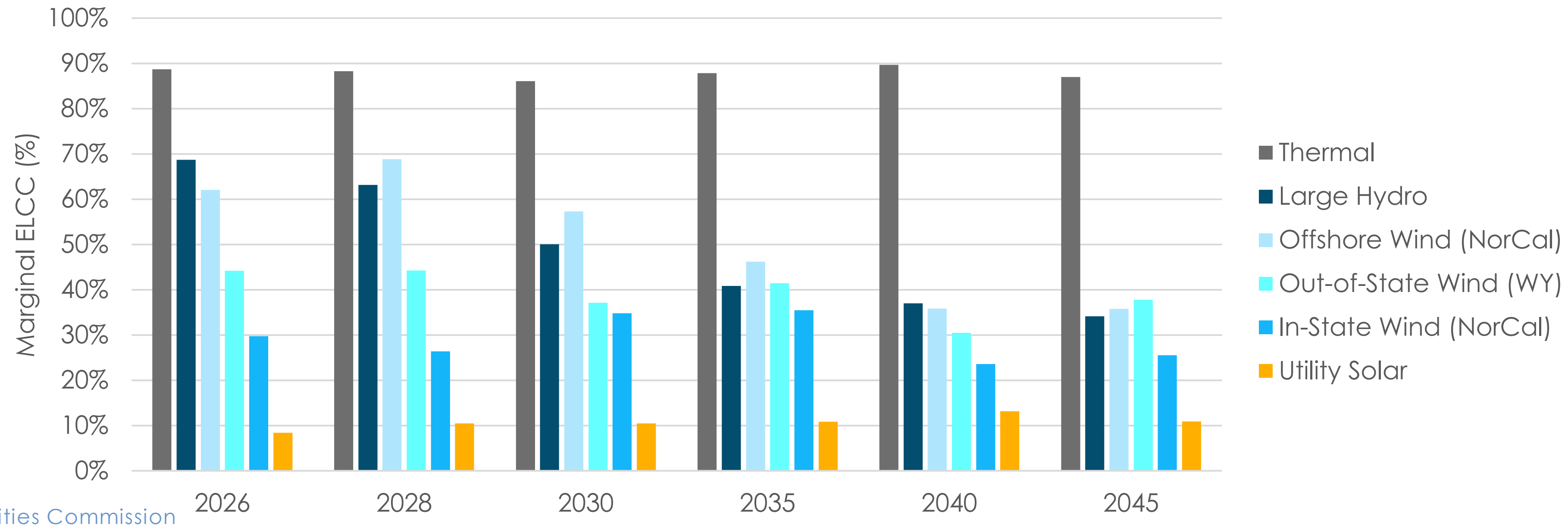
Modeled Year	Interpolated Year

Resource Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility Solar	8%	9%	10%	10%	10%	11%	11%	11%	11%	11%	11%	12%	12%	13%	13%	13%	12%	12%	11%	11%
Customer Solar	7%	8%	8%	8%	7%	8%	8%	8%	9%	9%	10%	10%	10%	11%	11%	11%	10%	10%	9%	9%
In-State Wind (NorCal)	30%	28%	26%	31%	35%	35%	35%	35%	35%	35%	33%	31%	28%	26%	24%	24%	24%	25%	25%	26%
In-State Wind (SoCal)	20%	18%	15%	15%	15%	16%	17%	18%	19%	19%	18%	16%	14%	12%	11%	11%	11%	11%	12%	12%
Out-of-State Wind (WY)	44%	44%	44%	41%	37%	38%	39%	40%	41%	41%	39%	37%	35%	33%	30%	32%	33%	35%	36%	38%
Out-of-State Wind (ID/WA/OR)	27%	22%	17%	21%	25%	26%	27%	27%	28%	29%	27%	25%	23%	22%	20%	20%	20%	19%	19%	19%
Out-of-State Wind (AZ/NM)	43%	43%	43%	39%	36%	37%	38%	40%	41%	42%	39%	37%	34%	32%	29%	30%	31%	32%	33%	34%
Offshore Wind (NorCal)	62%	65%	69%	63%	57%	55%	53%	51%	48%	46%	44%	42%	40%	38%	36%	36%	36%	36%	36%	36%
Offshore Wind (SoCal)	42%	45%	47%	39%	30%	29%	28%	26%	25%	23%	22%	20%	19%	18%	16%	17%	19%	20%	21%	22%
Geothermal	91%	91%	92%	89%	87%	87%	87%	87%	87%	87%	87%	88%	88%	88%	88%	89%	89%	89%	89%	90%
Small Hydro	42%	39%	36%	33%	30%	28%	26%	24%	22%	21%	21%	21%	21%	21%	21%	20%	20%	20%	19%	19%
Large Hydro	69%	66%	63%	57%	50%	48%	46%	44%	43%	41%	40%	39%	39%	38%	37%	36%	36%	35%	35%	34%
Storage 4-hr	92%	84%	75%	49%	22%	21%	20%	19%	18%	17%	17%	17%	17%	17%	17%	17%	17%	16%	16%	16%
Storage 8-hr	97%	92%	87%	63%	39%	36%	32%	29%	25%	22%	24%	25%	27%	28%	30%	30%	31%	31%	32%	32%
Storage 12-hr	94%	92%	91%	69%	47%	42%	37%	32%	27%	22%	24%	25%	27%	28%	30%	30%	31%	31%	32%	32%
Storage 24-hr	96%	94%	92%	74%	56%	50%	44%	37%	31%	25%	27%	29%	30%	32%	34%	34%	34%	34%	34%	35%
Storage 100-hr	99%	99%	98%	86%	74%	69%	64%	58%	53%	48%	49%	50%	51%	52%	53%	53%	52%	52%	51%	51%
Pumped Storage	90%	87%	85%	66%	48%	43%	37%	32%	27%	22%	24%	25%	27%	28%	30%	30%	31%	31%	32%	32%
Demand Response	94%	85%	76%	59%	42%	36%	30%	24%	18%	12%	12%	11%	11%	11%	11%	10%	10%	10%	9%	9%
Thermal Resources	89%	88%	88%	87%	86%	86%	87%	87%	87%	88%	88%	89%	89%	89%	90%	89%	89%	88%	88%	87%

Note that these ELCCs are specifically developed for filing requirements, using modeled portfolio from RESOLVE

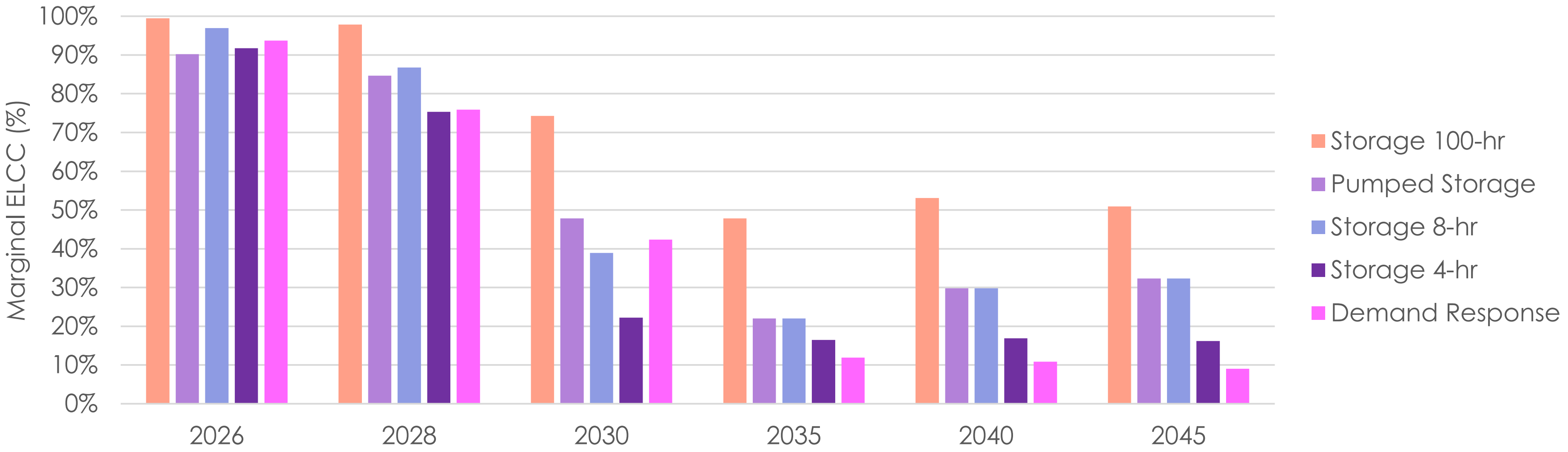
Renewable, Hydro, Thermal ELCCs Stable Over Time

- Solar marginal ELCCs remain low (but not zero) for all modeled years
- Out-of-state and in-state wind provide higher marginal ELCCs than solar and remain stable across the modeled years
- Offshore wind ELCCs start high but declines over time as more wind and energy limited resources are added to the portfolio (Humboldt ELCCs higher than Morro Bay)
- Hydro ELCCs decline over time as well as system becomes more energy constrained by 2035
- Firm ELCCs generally stable at 85-90%



Storage and DR ELCCs Decline in Future Years

- Storage marginal ELCCs remain high in the near term amidst large solar additions but decline as storage saturates and critical hours spread out in an energy constrained system
  - Significant decrease in 2030 as large amount of solar and storage are added to meet GHG reduction requirements (making the system over-reliable)*
  - Long-term value post 2035 driven by continued solar and wind capacity additions, load shape changes, and increasing winter loss of load risk
  - Even 100-hr storage shows a significant decline in marginal ELCC in 2035 driven by multiple days of critical energy need, charging constraints, and low round-trip efficiency
- DR follows storage trends due to its energy duration limitations



* This 2030 marginal ELCC is lower than an incremental ELCC study focused only on meeting RA needs would be (since this portfolio built more storage than needed for RA due to binding GHG constraints).

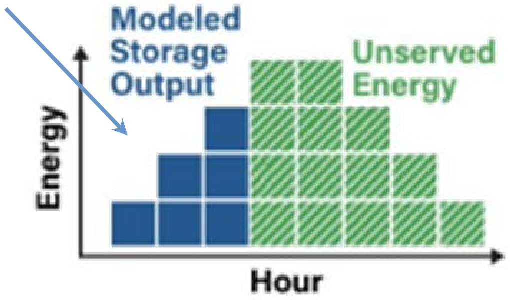
Critical Hours Modeling Approach

- Critical Hours are hours in which additional resource MWh will reduce unserved energy
  - On days in which a loss-of-load event occurs when storage energy is exhausted, critical hours also includes hours of storage discharge
  - In systems that have energy charging sufficiency constraints for storage, critical hours can also include hours of storage charge *(additional SERVM model development will be needed to map out those hours)*
- Additional SERVM runs were performed to determine the Critical Hours
  - In these runs, storage was dispatched using the **Energy Equity** method

Non-Energy Equity

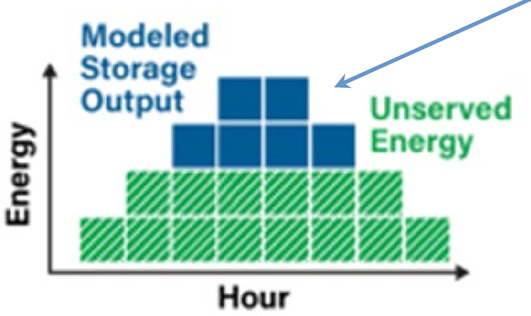
No output in **unserved energy** hours means 0 UCAP

Storage discharges at the **start of the event**



Energy Equity

Output in **unserved energy** hours counts towards UCAP



Storage dispatched to minimize total unserved energy **across the event**

Image Source: Brattle Group

Critical Hours Are Spread Across Hours and Seasons Over Time

- Critical hours spread out as energy-constrained events become more frequent
- Critical hours shift from summer-only to both summer and winter

Critical hours concentrated in summer evenings

2026: % of Critical Hours in Each Month-Hour

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.31%	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10%	0.21%	0.58%	0.58%	17.86%	75.59%	3.23%	0.58%	0.58%	0.38%	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2045: % of Critical Hours in Each Month-Hour

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	-	-	-	-	-	-	-	-	-	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
Feb - Jul	-	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-	-
Sep	4.76%	4.76%	3.85%	1.94%	2.33%	5.05%	-	-	-	-	[illegible]	[illegible]	[illegible]	-	0.74%	1.61%	3.99%	4.76%	4.76%	4.76%	4.76%	4.76%	4.76%	4.76%
Oct	-	-	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	-	-	-	-	-	-	-	-	-	-	-
Nov	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	-	-	-	-	-	-	-	-	-	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%
Dec	1.78%	1.79%	1.55%	1.54%	1.54%	1.54%	1.61%	0.28%	0.18%	-	-	-	-	-	-	-	1.76%	1.78%	1.78%	1.78%	1.78%	1.78%	1.78%	1.78%

New critical hours in winter months

Increasing spread of summer critical hours

Modeling Results

Critical Hours Heatmaps: 2028-2030

- By 2030, critical hours spread to late afternoon and later into the night, contributing to storage ELCC declines

2026

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.31%	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10%	0.21%	0.58%	0.58%	17.86%	75.59%	3.23%	0.58%	0.58%	0.38%	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2028

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	-
Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.21%	3.67%	3.67%	12.01%	61.00%	3.97%	3.67%	3.67%	3.67%	0.46%
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2030

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	0.12%	-	-	-	-	-	-	-	-	-	-	-	-	0.10%	1.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%	2.43%
Sep	0.03%	-	-	-	-	-	-	-	-	-	-	-	-	-	0.95%	6.24%	7.98%	7.98%	13.36%	8.01%	7.98%	7.98%	7.98%	7.98%
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Modeling Results

Critical Hours Heatmaps: 2035-2045

- By 2035, critical hours spread out even further and expand into winter months by 2040-2045

2035

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	0.57%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%
Sep	9.16%	0.78%	-	-	-	1.94%	-	-	-	-	-	-	-	-	0.28%	8.79%	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2040

Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	0.28%	0.28%	-	-	-	-	-	-	-	-	-	-	-	-	-	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%
Sep	6.73%	4.43%	-	-	-	3.66%	-	-	-	-	-	-	-	-	-	5.41%	6.73%	6.73%	6.90%	6.73%	6.73%	6.73%	6.73%	6.73%
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	-	-	-	-	-	-	-	-	-	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
Dec	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	-	-	-	-	-	-	-	-	-	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%	0.62%

2045

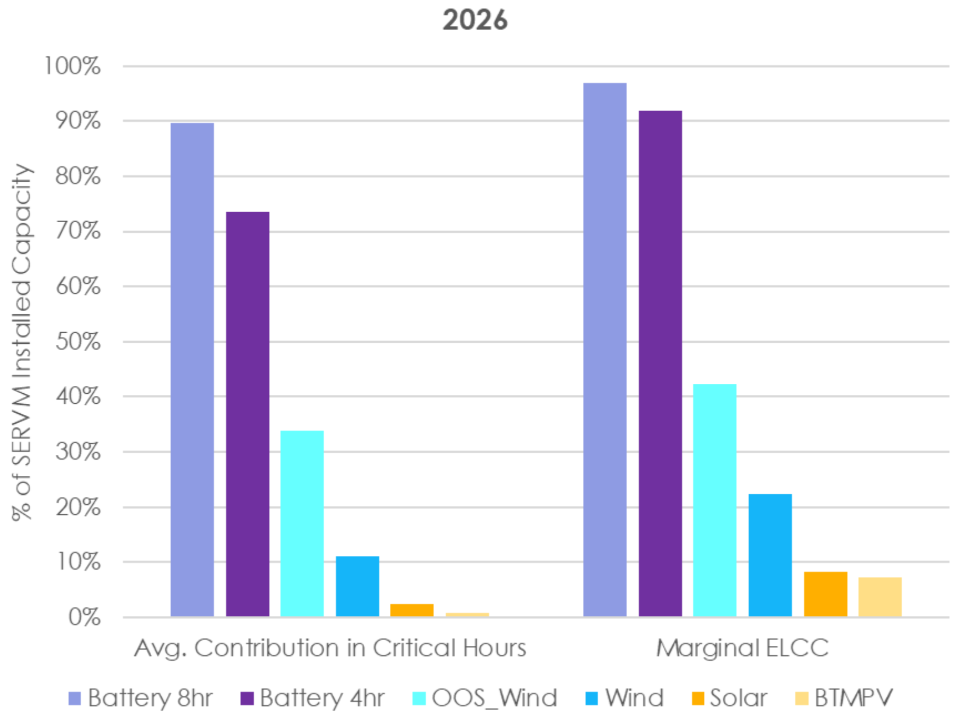
Month / HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	-	-	-	-	-	-	-	-	-	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
Feb - Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sep	4.76%	4.76%	3.85%	1.94%	2.33%	5.05%	-	-	-	-	-	-	-	-	0.74%	1.61%	3.99%	4.76%	4.76%	4.76%	4.76%	4.76%	4.76%	4.76%
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	-	-	-	-	-	-	-	-	-	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%	0.73%
Dec	1.78%	1.79%	1.55%	1.54%	1.54%	1.54%	1.61%	0.28%	0.18%	-	-	-	-	-	-	-	1.76%	1.78%	1.78%	1.78%	1.78%	1.78%	1.78%	1.78%

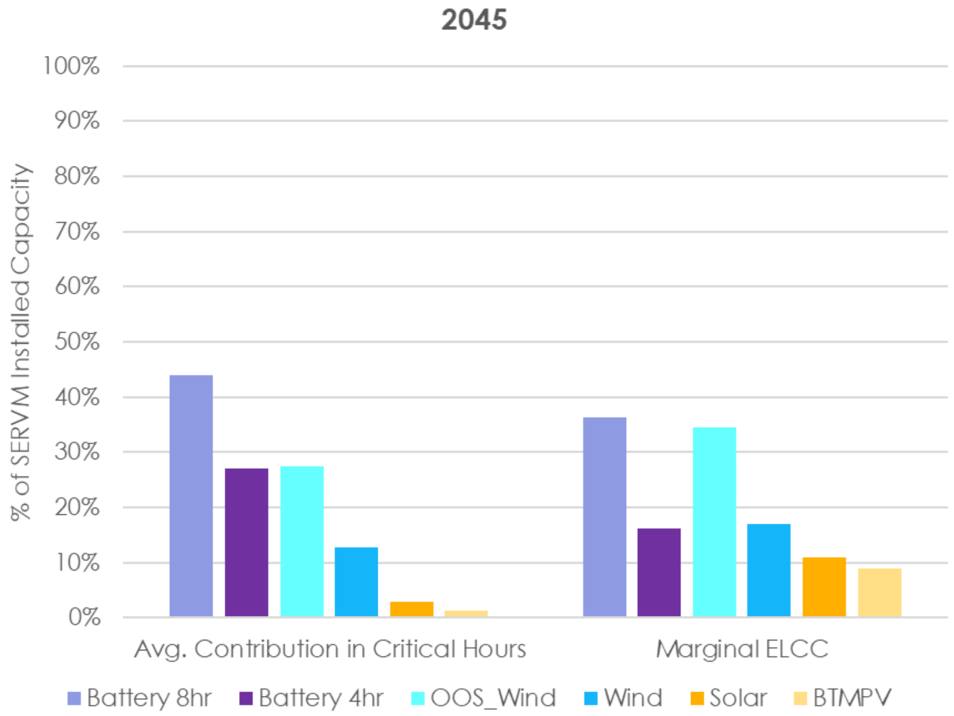
Evolving Nature of Events

- As shown on previous slides, two notable trends were observed in critical hours from 2026 to 2045:
  - Critical hours spread out as energy-constrained events become more frequent.
  - Critical hours shift from summer-only to both summer and winter.
- Evolution of critical hours also affects resource marginal ELCCs.
  - For diagrams and dispatch charts that illustrate why the increasing frequency of energy-constrained events leads to lower ELCCs for storage, see additional slides on “Evolving Nature of Events” in the Appendix.

ELCCs Are Consistent with Contributions in Critical Hours

- Declining marginal ELCC values driven by declining contributions of resources during critical hours (e.g., storage ELCCs decline as storage dispatch is spread across increasing number of critical hours)
    - Average contributions in charts are weighted based on weather year probability
- Minor differences between marginal ELCC and average contribution due to interactive effects between resource types and difference between output and availability
    - SERVM captures key interactive effects that impact marginal reliability contributions, including solar charging storage and delaying discharge, impact on gas plant outages of charging storage with gas, etc.





24-26 IRP Need Determination and Allocation Under the Marginal ELCC Framework

Based on Filing Requirements portfolio, to be used for LSE planning in 2024-26 IRP filings

Need Determination and Allocation Overview

Key steps for Need Determination and Allocation include:

1. **Perform additional system calibration runs**
    1. Similar to marginal ELCC modeling, system was calibrated to 0.1 LOLE by retiring resources and/or adding PCAP. For need determination, staff refined winter maintenance and added back N<>S transmission constraints (that were removed from ELCC studies to avoided potential distortions) to better reflect expected future need to be reflected in SERVM PSP modeling.
2. **Adjust SERVM capacity** to align with reliability requirements
    - Energy-only resources are removed from the RPN since they would not count towards meeting resource adequacy requirements.*
    - Capacity from "remote generators" outside of CAISO that deliver energy but not RA capacity into CAISO was also removed.
3. **Calculate the Reliability Procurement Need (RPN)** at the CAISO system level
    - RPN is calculated as the sum-product of the adjusted capacity and the marginal ELCC by resource type. It also accounts for resource retirements and PCAP additions (see Step 1).
    - **Years modeled**: 2026, 2028, 2030, 2035, 2040, 2045
4. **Calculate the LSE share of the RPN (%) based on critical hours load share**
    - The LSE share is based on the weighted average load share during critical hours, in which the weights are the frequency of loss of load during each critical hour.
    - Each LSE's individual Reliability Procurement Requirement (RPR) can then be calculated by multiplying the RPN with its critical hours load share percentage.

*However, energy-only solar resources that are co-located with storage can be counted towards reliability requirements and were not removed from SERVM capacity.

Refined Calibration Assumptions

- **Maintenance Rates:** For the purpose of need determination and allocation, staff updated the winter maintenance rates assumed for thermal for 2040 and 2045 to reflect expected maintenance trends as reliability risk shifts into winter:
  - Default maintenance rates in 2026, 2028, and 2030 (scheduled according to max daily net peak load across all weather years)*
  - Zero maintenance in 2035*
  - Reduced winter maintenance in 2040 & 2045
    - Winter maintenance was reduced in 2040 and 2045 by allowing SERVM to schedule 20% of maintenance based on weather year-specific net load.
- **N<>S Constraint:** Constraint was enforced for need determination study. Maximum North-South transmission capacity constraints reflect transmission expansion selected by RESOLVE in future years.
- The impacts of the updated assumptions are shown in table below.

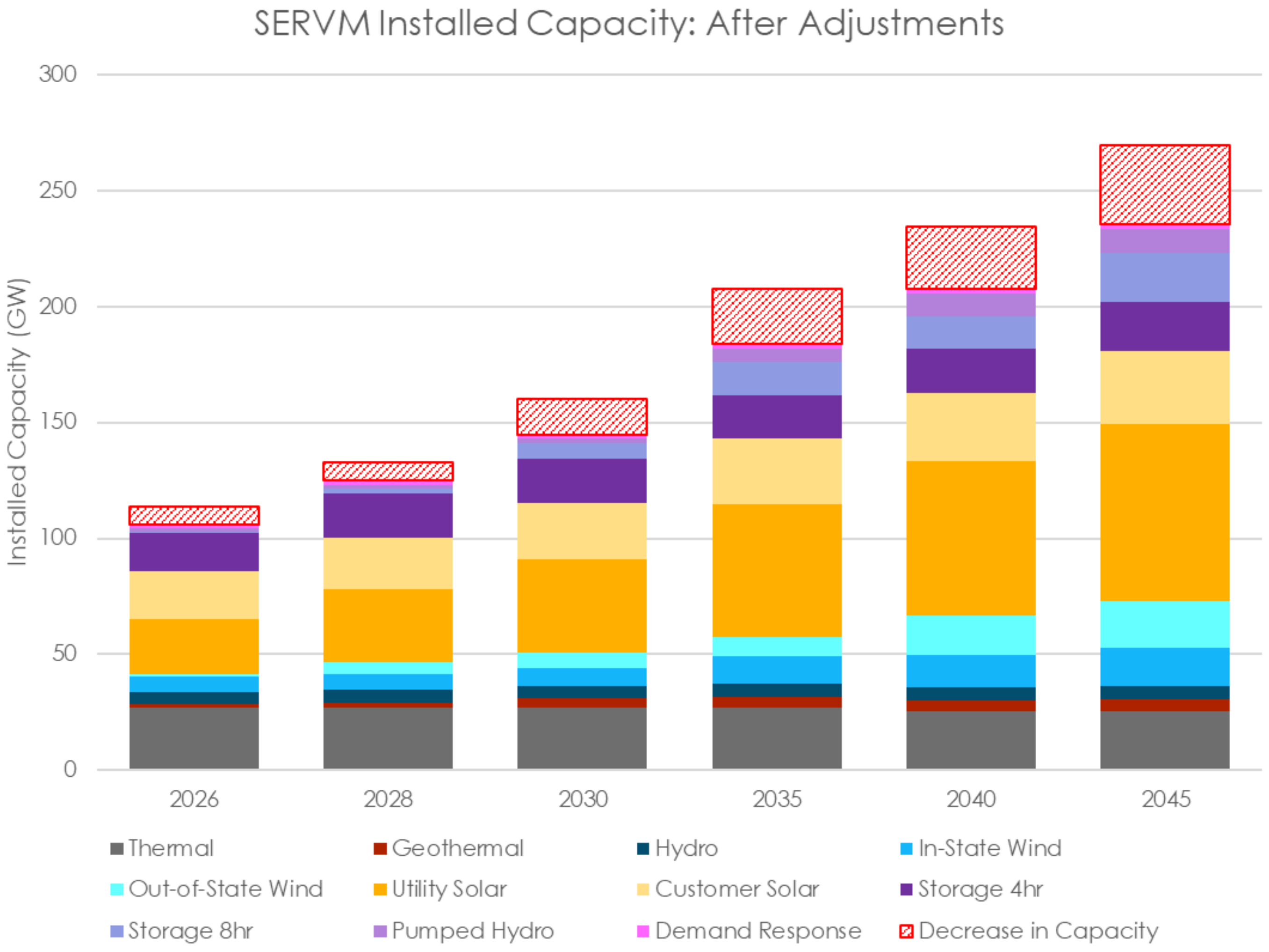
Impact of N<>S Constraints and Thermal Maintenance Updates on Calibration Results

units = MW	2026	2028	2030	2035	2040	2045
Calibration Adjustment in Marginal ELCC Modeling	(160)	(2,665)	(5,997)	(7,532)	(5,924)	(8,936)
Impact of Refined Assumptions	(66)	+1,399	+3,443	+8,182	+7,024	+9,086
Calibration Adjustment in Need Determination	(227)	(1,266)	(2,554)	650	1,100	150

*This assumption is unchanged from marginal ELCC modeling but included for completeness.

SERVM Capacity Adjustments

- Adjustments were made to match counting conventions to be used by LSEs in their RDT
  - Existing hydro, thermal, geothermal, pumped hydro
    - Use Sept NQC MW × marginal ELCC %
  - Other existing resources and all new resources
    - Use nameplate MW × marginal ELCC %
- Adjustments were also made to removing EO resources & remote generators (~34 GW total by 2045), mostly for solar.

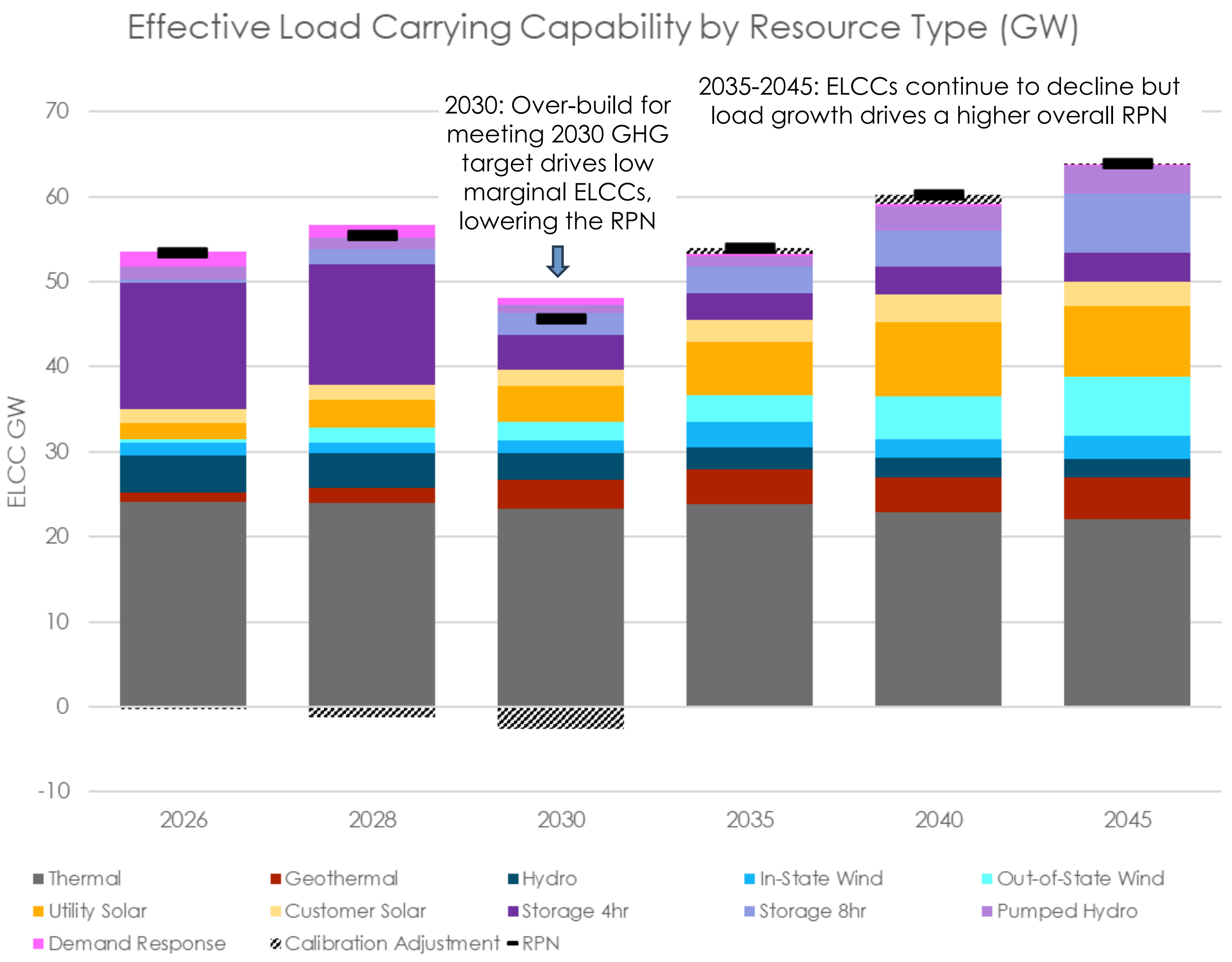


Reliability Procurement Need

- **Reliability Procurement Need (RPN)** is total sum of:
  - Sum-product of adjusted capacity and marginal ELCC → ELCC GW by resource type.
  - Calibration adjustment to meet 0.1 LOLE.
- RPN = total height of ELCC stacks (net of calibration adjustment)
  - RPN by year in GW*:

2026	2028	2030	2035	2040	2045
53.4	55.4	45.6	53.9	60.2	63.9

***These RPN values should be used by LSEs for planning purposes in their 2024-26 IRP filings.** RPN values were derived with updated marginal ELCCs based on FR portfolio and therefore may differ from those in the 2025 RCPPP Staff Proposal. However, the methods used are consistent with those described for Option 1 (new and existing resources) in the Staff Proposal.



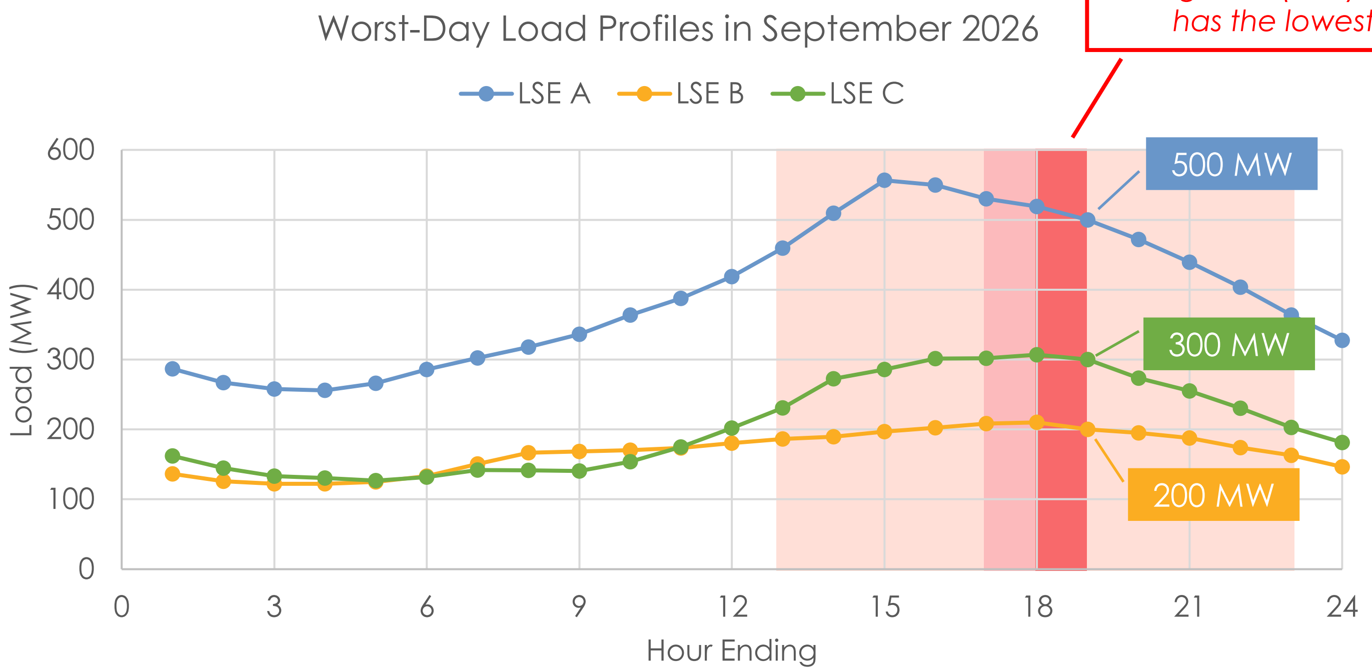
Calculate Critical Hours Load Share by LSE

- **Critical Hours Load Share** = weighted average load share during critical hours
  - For each LSE, calculate their share of the CAISO load during each critical hour
  - Weight each critical hour load share by the frequency of loss of load in that critical hour
- Critical Hours Load Share is used as each LSE's % share of the Reliability Procurement Need
- Given that the allocation is based on confidential LSE load forecast, the results are not shown in this deck and will be distributed separately by the CPUC

Example Calculation: 2026 with 3 LSEs

- Critical hours load share is weighted based on frequency of loss of load during each critical hour
- **Example:** In 2026, loss of load risk is highest in September, particularly HE19
    - Graph shows 3 example LSEs with different load shapes
    - Resulting weighted-average critical hours load share is very close to HE19 load share

LSE A has highest load share during HE19 (50%), while LSE B has the lowest (20%)



	1	2 - 13	14	15	16	17	18	19	20	21	22	23	24	
Critical Hour Frequency	0.0	0.0	0.1	0.1	0.4	0.4	11.5	48.7	2.1	0.4	0.4	0.2	0.0	
LSE Load Share (% of System)														**Weighted Average**
LSE A	49%	…	52%	54%	52%	51%	50%	50%	50%	50%	50%	50%	50%	*50%*
LSE B	23%	…	20%	19%	19%	20%	20%	20%	21%	21%	22%	22%	22%	*20%*
LSE C	28%	…	28%	28%	29%	29%	30%	30%	29%	29%	29%	28%	28%	*30%*

Used as LSE's % share of the RPN

Appendix

Marginal ELCC Modeling: Additional Assumptions

- **Offshore Wind:** Humboldt used to represent NorCal offshore wind; Morro Bay used to represent SoCal offshore wind.
- **Out-of-State Wind:** WY = 100% Wyoming; ID/WA/OR = 33% each; AZ/NM = 50% each.
- **Import Limits:** 11 GW in all off-peak hours, 4 GW in peak hours (summer HE 17-22); 2.33 GW ramp import constraint between 4 and 11 GW during summer months (applied in HE 15-16 and HE 23-24)
- **460 scenarios:** 23 weather years x 20 random draws.
- **N<>S Constraint:** Relaxed for marginal ELCC runs.
- **Storage RTE:** See table, *right*.

Storage RTE

	RTE
4-hr Storage	85%
8-hr Storage	85%
12-hr Storage	75%
24-hr Storage	60%
100-hr Storage	45%

Update to Storage Dispatch Algorithm

Improved scheduling for both storage charging & discharging to maintain SOC in all resources over periods of months rather than days by implementing the following heuristics:

- **Discharging Prioritization:** Only discharge from long duration resources first when net load is above a critical threshold
  - ***Key Benefit:*** *Utilizes shorter duration storage to serve load when long duration resources are not needed*
- **Charging Prioritization:** Dynamically prioritize which duration resources to charge with objective of maximizing total SOC & total capacity availability
  - ***Key Benefit:*** *Ensures longer-duration batteries maintain higher SOC by giving them more charging hours*

ELCC Modeling Results

Thermal Subclass Marginal ELCCs

- Thermal subclass ELCCs were derived from the aggregated thermal resource marginal ELCC.
  - For each subclass, ELCC derate relative to the aggregate thermal ELCC was proportional to the equivalent forced outage rate on demand (EFORd) for that subclass.
  - EFORd varied by year; 2030 EFORd values are shown for illustrative purposes.
  - All cogen units projected to retire by 2040.

Modeled Year	Interpolated Year

Resource Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Thermal Resources	**89%**	**88%**	**88%**	**87%**	**86%**	**86%**	**87%**	**87%**	**87%**	**88%**	**88%**	**89%**	**89%**	**89%**	**90%**	**89%**	**89%**	**88%**	**88%**	**87%**
Biogas	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Biomass/Wood	100%	99%	99%	99%	99%	99%	99%	98%	98%	98%	98%	98%	99%	99%	99%	99%	98%	98%	98%	98%
Cogen	92%	91%	91%	91%	90%	90%	90%	90%	90%	90%	91%	92%	92%	93%	N/A	N/A	N/A	N/A	N/A	N/A
Gas CC	86%	85%	85%	83%	82%	82%	82%	83%	83%	83%	84%	85%	86%	87%	88%	87%	87%	86%	85%	84%
Gas CT	69%	69%	69%	65%	62%	62%	62%	62%	61%	61%	64%	66%	69%	71%	74%	72%	71%	70%	68%	67%
ICE	94%	94%	94%	94%	93%	93%	93%	93%	93%	93%	94%	94%	95%	95%	96%	95%	95%	95%	94%	94%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Sample EFORd (%)	2030
Biogas	0.4%
Biomass/Wood	0.6%
Cogen	4.3%
Gas CC	7.8%
Gas CT	16.3%
ICE	2.9%
Nuclear	0.0%

Evolving Nature of Events

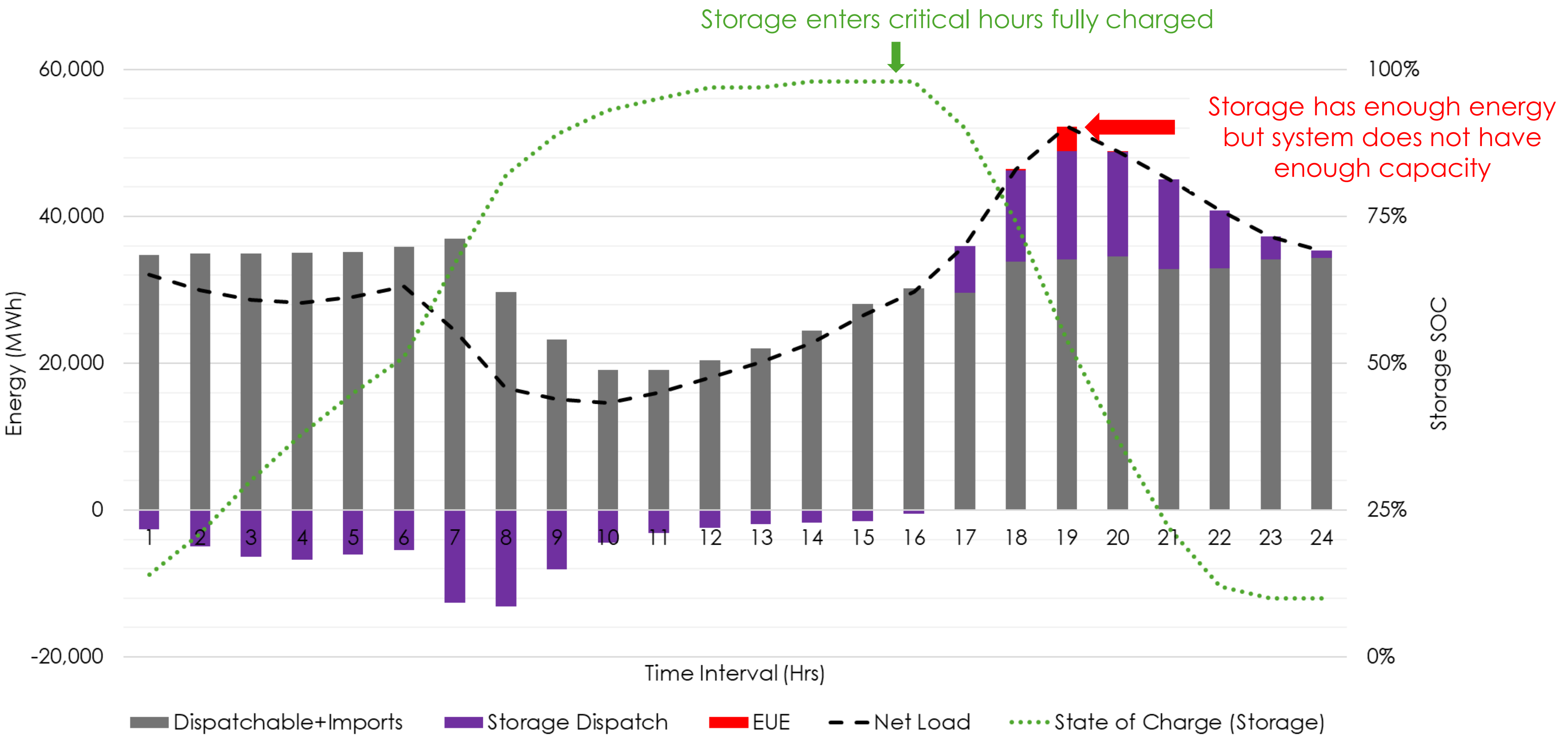
EUE Events
(influenced by storage constraints)

- **Discharging Capacity Constrained**
  Storage is fully charged going into a reliability event but has **insufficient instantaneous discharging capacity** to meet demand during a narrow set of critical hours.
- **Energy-Constrained**
  - **Charging-Constrained**
    *By mid-2030s, discharging hours remain critical but **charging constraints** also begin to limit storage effectiveness.*
    - **Surplus Generation Constrained**
      Limited surplus energy does not allow for batteries to fully recharge.
    - **Charging Capacity Constrained**
      Even when surplus energy is available, **storage cannot use all available energy** due to insufficient instantaneous charging capacity, limiting its effectiveness.
  - **Discharging-Constrained**
    Storage SOC is regularly exhausted before the end of events. **Insufficient stored energy** across consecutive hours or days becomes the limiting factor.

Evolving Nature of Events

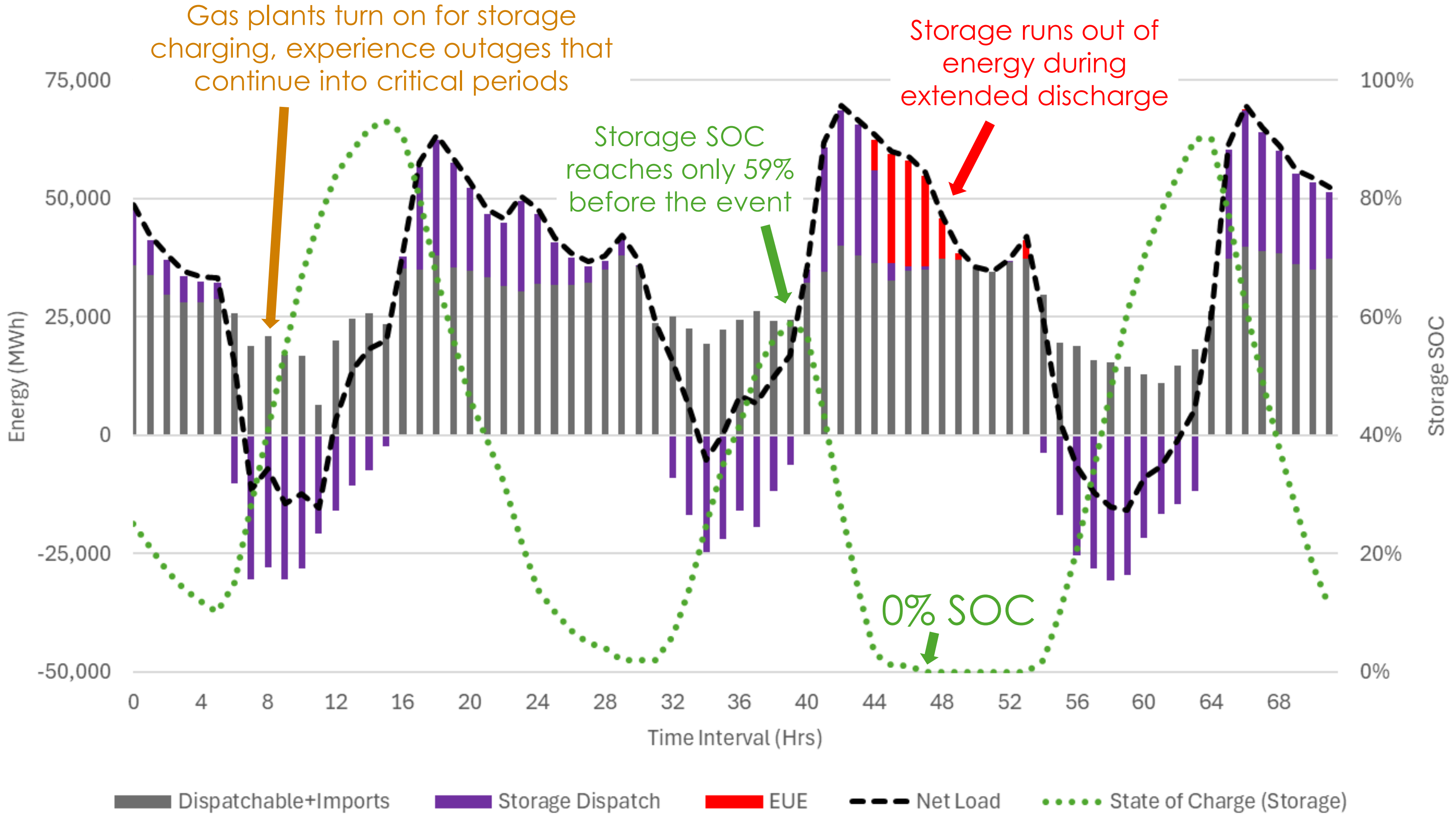
Capacity Constrained Example (2026)

- Storage enters event fully charged, but maximum discharge capacity is insufficient to meet demand, leading to lost load



Energy Constrained Example (2040)

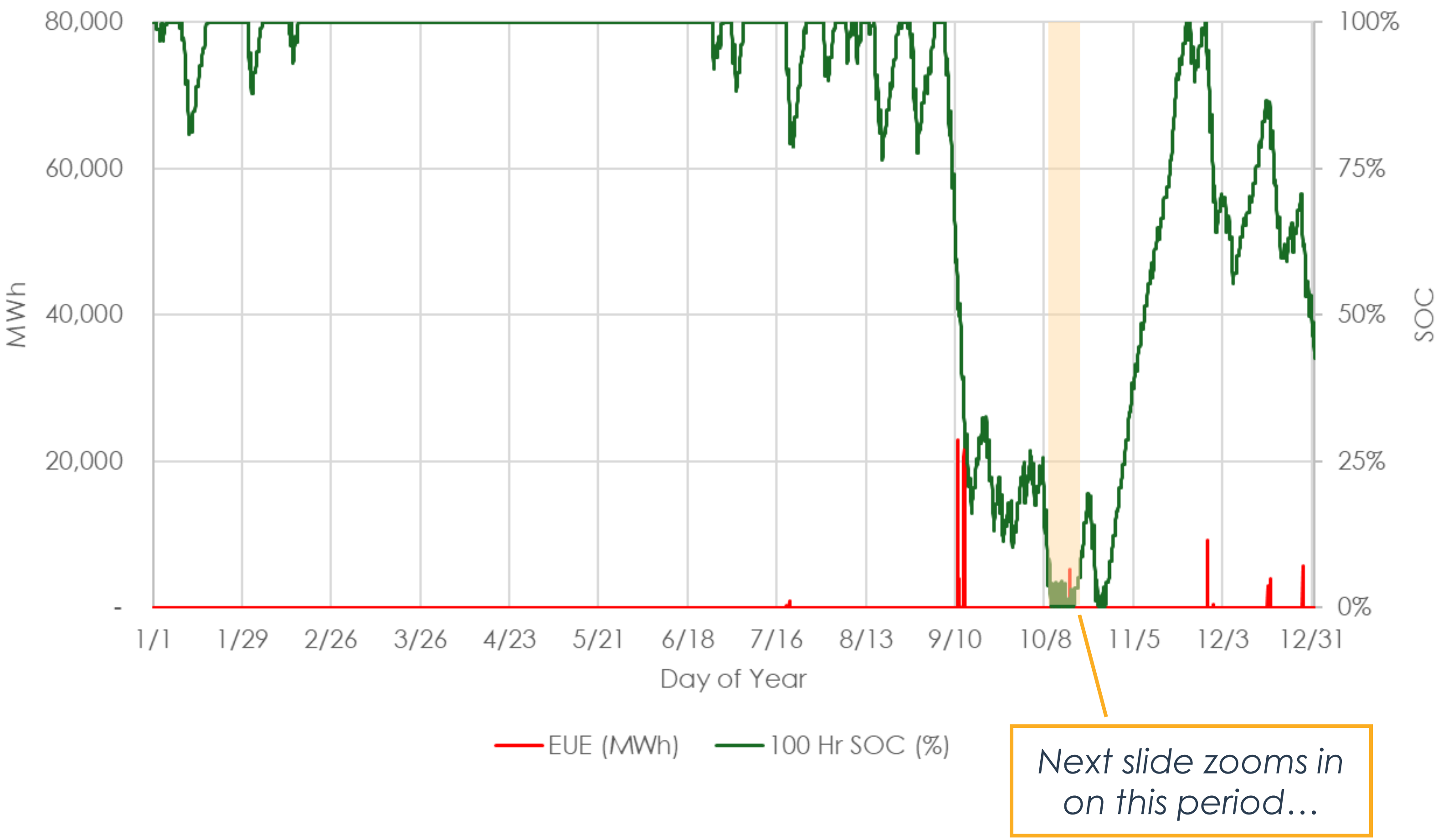
- Storage enters the event with SOC below target due to limited surplus energy or insufficient charging capacity
- During critical hours, storage exhausts its SOC (i.e., becomes energy-limited) which leads to lost load



Note that this chart shows raw storage dispatch prior to the energy equity analysis.

LDES SOC Can Get Depleted Over Multi-Day Events (2040)

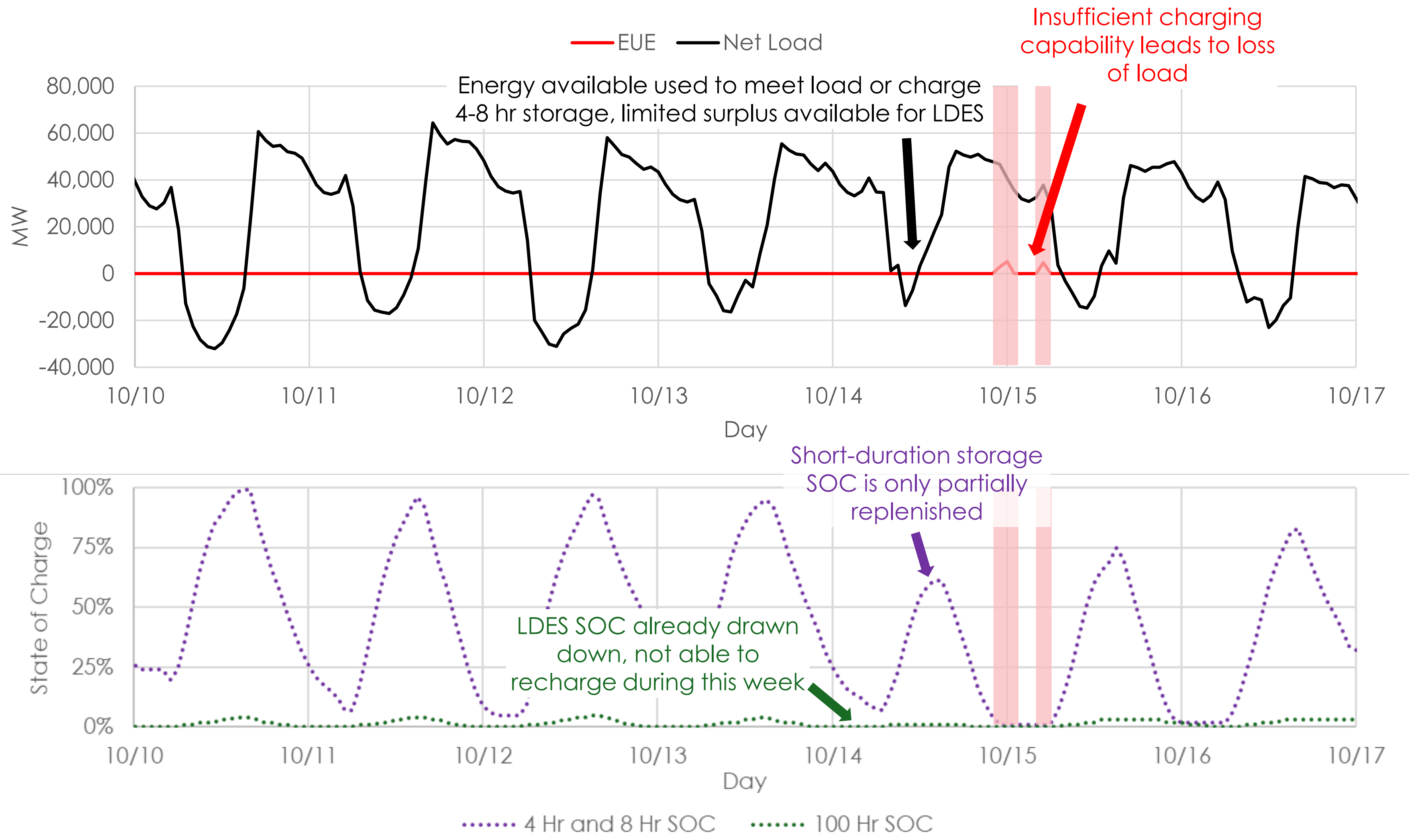
- ELCC studies capture extended multi-day to week energy availability conditions that are critical to valuing long duration storage
- Chart shows how LDES SOC changes over a full year in one SERVM case (model year 2040, weather year 2015)
  - SOC gets depleted when there are multi-day reliability events & insufficient excess energy to recharge



Evolving Nature of Events

LDES SOC Challenges (Zoomed In)

- LDES SOC is drawn down over several weeks of high net load, starting in early September
- System is **charging constrained** prior to the event on 10/14-10/15
  - Available surplus energy and charging capability are insufficient to restore LDES SOC
  - Excess energy is being used to recharge higher RTE short-duration storage



RPN Calculation

EO Resources & Remote Generators Removed

- This table shows the combined capacities of energy-only (EO) resources (except EO resources colocated with storage) and remote generators, which were removed from SERVM capacity.
- Other resource types did not have any EO resources or remote generators.

Adjustments to SERVM Capacity

	2026	2028	2030	2035	2040	2045
Utility Solar	-3,637	-4,327	-11,308	-19,457	-22,257	-29,827
In State NorCal Wind	-230	-230	-230	-780	-780	-780
In State SoCal Wind	-6	-6	-6	-6	-6	-6
Out of State Wind - ID/WA/OR	-200	-200	-200	-200	-200	-200
Out of State Wind - AZ/NM	-1,851	-1,851	-1,851	-1,851	-1,851	-1,851
Geothermal	-426	-426	-426	-426	-426	-426
Small Hydro	-17	-17	-17	-17	-17	-17
Storage 4hr	-164	-164	-164	-164	-164	-164
Thermal	-967	-967	-967	-967	-967	-967