(ATTACHMENT A)

California Public Utilities Comm

January 17, 2025

Energy Division Track 3 Proposals

In Proceeding R.23-10-011

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Proposal 1. Evaluating Unforced Capacity (UCAP) or Unforced Capacity-Light for Thermal Resources and Battery Storage

Background

Energy Division Staff (ED Staff or Staff) proposed an initial framework for using estimated unforced capacity (UCAP) in modeling efforts in January, 2024[1]. Since that time, Staff have continued to refine the proposal considering both formal and informal party feedback.

Note that ED Staff have been engaged in coordination discussions with CAISO staff regarding key areas of its proposal. Through these discussions Staff have been actively coordinating to build common understanding of the merits and implementation requirements of various UCAP designs, including feedback provided on previous Energy Division UCAP proposals and in CAISO's stakeholder process. Continued discussion with CAISO staff is underway to develop more consensus. The current proposal incorporates elements arising from those discussions. Ongoing coordination with CAISO in sourcing data and formula definitions;

- Using outage data from CAISO's Outage Management System instead of the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS);
- Identifying nature-of-work codes to select CAISO's curtailment data for forced outages;
- Applying UCAP across both modeling and resource-counting, with key distinctions in formulations for either purpose;
- Better integrating UCAP methodology into slice-of-day framework; and
- More consistency between capacity accreditation/resource counting and multi-year modeling.

Data Sources

While ED Staff previously proposed using a combination of CAISO data for derates due to ambient temperatures and NERC's GADS for forced outages, Staff now propose to use CAISO's curtailment data as the source for all outages. This data is publicly available and therefore not subject to the confidentiality concerns associated with GADS. This change allows us to filter out the individual nature of work codes (separating outages into equipment failure, planned outages, ambient derates, fuel insufficiency, or permitting among other types) and calculating specific outage metrics that focus on only the precise categories of use in modeling and resource accreditation. Additionally, outage data for battery storage systems is available from CAISO data, while is not available in GADS.

Proposed UCAP Framework

Staff propose to apply UCAP for the purposes of capacity accreditation (setting Qualifying Capacity values) for storage and dispatchable thermal resources and reliability modeling. The only difference between the uses would be on how ambient temperature derates are treated. This framework will not affect resources subject to probabilistic Qualifying Capacity methodologies, such as wind and solar resources, although hybrid resources featuring storage and solar components will require further consideration. The UCAP calculations will utilize each unit's recorded performance whenever possible,

[1] R.23-10-011 January 22, 2024 ALJ Ruling -Track 1 Staff Proposals

substituting class-based median values as when necessary, as described in the later section on Aggregation Calculations.

In the most basic case, the proposed methodology involves four steps:

1. Evaluate forced outage rates for each resource and hour within the evaluation period;
2. Identify the most constrained hours systemwide for each season
3. Filter the hourly forced outage rates for the most constrained hours; and
4. Calculate forced outage rates with weighting and aggregation for each resource and season.

This methodology applies to resources with sufficient historic outage data to determine their own unique UCAP values. For specific units that do not have sufficient or missing/outlier data, Staff will substitute capacity-weighted medians for the appropriate resource class in the outage rate calculation. UCAP values will be evaluated through the CPUC's existing Qualifying Capacity process on an annual basis.

Evaluation Period

Staff propose that three complete prior years be used in evaluating the UCAP values for a given resource. Each year will be weighted such that more recent data contributes more significantly toward the final UCAP values than prior data as follows:

- Year y-1: $c_y = \frac{4}{9} \cong 44.45\%$
- Year y-2: $c_y = \frac{3}{9} \cong 33.33\%$
- Year y-3: $c_y = \frac{2}{9} \cong 22.22\%$

This weighting distribution decreases linearly throughout the evaluation period, providing a bias toward more current data while attenuating the impact of outlying events. This also allows resources to benefit from maintenance and improvement projects that improve outage rates within a reasonable timeframe, as increased reliability could significantly affect UCAP values within the first two years.

New Resources and Missing Resource-Level Outage Data

As new resources are brought online, the historic outage data that would otherwise be used to evaluate their UCAP values will be substituted with capacity-weighted median values for each resource class. Within its first year of operation, its applicable UCAP values will be determined based solely on resources within its class put into service within the previous ten years. As a new resource's own outage data becomes available in the following years, UCAP will be determined using individual rather than the class-aggregated outages.

UCAP Formulas

This proposal is intended to harmonize methodologies for resource counting and loss-of-load expectation modeling to the extent possible, although there are differences between the two processes that necessitate some distinctions discussed in later sections.

Hourly Outage Calculations

Forced outages can be either partial or full, and may last minutes or hours, so we propose adapting the formula from NERC's GADS manual[2] for Equivalent Forced Outage Deration Hours (EFDH) to determine the outage rate for each hour. We propose modifying the GADS' definition of EFDH as follows, to be evaluated on an hourly basis for each resource, yielding an Equivalent Forced Deration (EFD), which accounts for partial derations as well as derations constituting less than the full hour:

Equation 1 – Equivalent Forced Deration

$$[EFD]_{r,h} = \sum_{i \in NoW} \frac{[Derating\ Duration]_{r,h,i} \times [Size\ of\ Reduction]_{r,h,i}}{Pmax_r}$$

Where

r indicates a generation or storage resource;

h is a single hour within the three-year evaluation period;

i indicates a reported outage with a nature-of-work within the selected set NoW;

$[EFDH]_{r,h}$ is the Equivalent Forced Deration Hours for resource r in hour h;

$[Derating\ Duration]_{r,h,i}$ is the fraction of the hour, between 0 and 1, during which an outage is reported for resource r with nature-of-work i in hour h;

$[Size\ of\ Reduction]_{r,h,i}$ is the MW of curtailment as reported to CAISO for resource r with nature-of-work i in hour h; and

$Pmax_r$ is the tested performance maximum capacity of resource $Pmax_r$ as reported to CAISO.

Filtering

To integrate with CPUC's Slice-of-Day RA framework, we propose to apply two UCAP values for each resource, corresponding to the Equivalent Forced Outage Rates for a set of peak hours in two seasons. Peak hours for each season within each year of the evaluation period will be selected using a Supply Cushion approach, outlined in CAISO's Resource Adequacy Enhancements Draft Final Proposal- Phase 1 and Sixth Revised Straw Proposal (RA Enhancements Draft Proposal), originally published December 17, 2020.[3] Each year and season will be evaluated separately using the Supply Cushion methodology, with each hour considered independently. This will result in equal numbers of hours in the same seasons across all three years of the evaluation period excepting leap years, although the specific days and hours may vary. While the selected hours will be used in filtering outage data, the final UCAP values will apply to all hours in their respective seasons.

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[2] *GADS Brochure Data Reporter Software User Guide*. North American Electric Reliability Council. Release 2.10. 2004.

[3] https://stakeholdercenter.caiso.com/InitiativeDocuments/DraftFinalProposal-SixthRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

The Supply Cushion approach involves evaluating the hourly Supply Cushion, representing "how much Shown RA remains after serving net load, meeting Contingency reserves, and accounting for all outages," and selecting the 20% most constrained hours within each season. The proposed supply cushion for a given hour is adapted from the RA Enhancements Draft Proposal:

Equation 2 – RA Supply Cushion

$$
\begin{aligned}
[RA\ Supply\ Cushion]_h = {} & [Daily\ Shown\ RA\ excluding\ wind\ and\ solar]_h \\
& -[Planned\ Outage\ Impacts]_h \\
& -[Forced\ Outage\ Impacts]_h \\
& -[Net\ Load]_h \\
& -[Contingency\ Reserve]_h
\end{aligned}
$$

Where

> $[Daily\ Shown\ RA\ excluding\ wind\ and\ solar]_h$ is the sum total of all resource adequacy capacity for the given hour h without wind and solar resources;
>
> $[Planned\ Outage\ Impacts]_h$ is the sum total of all planned outages reported to CAISO for the given hour h, excluding outages among wind and solar resources;
>
> $[Forced\ Outage\ Impacts]_h$ is the sum total of all forced outages reported to CAISO for the given hour h, excluding outages among wind and solar resources;
>
> $[Net\ Load]_h$ is the historic system-wide load for the given hour h recorded from the 5-minute market, available from Production and Curtailment data sets published by CAISO; and
>
> $[Contingency\ Reserve]_h$ is the contingency reserve, estimated as 6% of gross load or 2500 MW, whichever was larger, for the given hour h.

The seasons will consist of summer and non-summer, defined as follows:

> Summer – May through October
> Non-Summer – January through April and November through December

Each of the terms in Equation 2 is evaluated for the CAISO balancing authority area, but the daily RA capacities excluding solar and wind resources are not currently available in a public dataset. ED Staff will continue working with CAISO to ensure the necessary data to implement the UCAP framework is publicly available.

Resource-Level Calculations

Staff propose sourcing outage data from CAISO's Prior Trade Day Curtailment Reports, which are publicly available flat file summaries of OMS data. Outage rates will be calculated using formulas derived from NERC's GADS manual for Equivalent Forced Outage Rate (EFOR). GADS' definition for EFOR includes terms for forced outage hours (FOH) as well as EFDH. The term EFD, as defined in Equation 1, combines both FOH and EFDH by allowing full outages, and we will refer to the resulting value as Unforced Capacity. The term is evaluated for each resource during the identified peak-demand periods each season as reflected in Equation 3.

Equation 3 – Resource-Level Equivalent Forced Outage Rate

$$EFOR_{r,S} = \frac{\sum_{h \in (s=S \cap p=P)} c_{y|h} \cdot EFD_{r,h}}{\sum_{h \in (s=S \cap p=P)} c_{y|h} \cdot \left[\left(EFD_{r,h} \middle| EFD_{r,h} = 1 \right) + SH_{r,h} \right]}$$

Where

h is a single hour within the three-year evaluation period;

r indicates a generation or storage resource;

S is a selected season as defined in the earlier section on Filtering, either Summer or Non-Summer;

s is the season corresponding to hour h

P is either the peak period for the given season identified through the RA supply cushion evaluation described in the previous section;

p is a flag corresponding to hour h defining the period as either peak or off-peak

$c_{y|h}$ is the weighting factor for the year y containing hour h as defined in the earlier section, Evaluation Period;

$EFD_{r,h}$ is the Equivalent Forced Deration evaluated for resource r in hour h as defined in Equation 1;

$h \in (s|h = S \cap p|h = P)$ identifies hours within the evaluation period matching the selected season S and peak or non-peak period P;

$\left(EFD_{r,h} \middle| EFD_{r,h} = 1 \right)$ includes EFD only during hours with full deration; and

$SH_{r,h}$ is the fraction of hour h resource r is reported as in-service.

The resulting term $EFOR_{r,S}$ will be the UCAP value for the given resource and season.

Aggregation Calculations

When aggregation across resources is required, such as when determining class-aggregated outage rates in lieu of historic resource-level data, Staff propose to do so within substantially similar units, as described in the following section on Resource Classes. Specifically, Staff proposes to apply capacity-weighted medians whenever aggregating outage rates across resources, using resource-level Pmax values, as the weighting capacities. This involves multiplying each resource's outage rate by its Pmax value, then sorting the resulting terms and selecting the resources in the 50th percentile, and finally applying the corresponding outage rate.

Resource Classes

Classes will be defined according to the Resource Type specified in CPUC's Master Resource Database, published on the Resource Adequacy Compliance Materials webpage.[4] For the purpose of aggregating historic data for new resources, only resources put into service within the previous ten years will be considered.

Proposed Applicable Nature-of-Work Codes

Staff selected the following set of nature-of-work codes reported to CAISO with the outage type of "FORCED" for the purpose of determining forced outage rates for LOLE modelling resources where GADS data is unavailable, and propose applying this set for the same purpose under UCAP:

- PLANT_TROUBLE
- METERING_TELEMETRY
- TRANSMISSION_INDUCED
- TECHNICAL_LIMITATIONS_NOT_IN_MARKET_MODEL
- TRANSITIONAL_LIMITATION
- ENVIRONMENTAL_RESTRICTIONS
- ICCP
- RTU_RIG
- AMBIENT_DUE_TO_TEMPERATURE (see below)

Forced outages with the nature-of-work "AMBIENT_DUE_TO_TEMPERATURE" will be subject to different treatments depending on the resource type, and for capacity accreditation versus LOLE modelling.

For resource counting, Staff note that this set of nature-of-work codes may not encapsulate all outages that should be considered in determining qualifying capacity values. Staff will continue to coordinate with CAISO to determine an appropriate set of outages codes for capacity accreditation.

Derates due to Ambient Temperatures

The output capacities of thermal power plants, i.e., units including steam and/or combustion turbines, are known to be sensitive to ambient temperatures due to the thermodynamic processes through which mechanical energy is derived from temperature and pressure differentials in the working fluid. Weather can also impact the effectiveness of auxiliary systems, resulting in derated capacities. For these reasons, we propose special treatments for forced outages reported with the nature-of-work code "AMBIENT_DUE_TO_TEMPERATURE". For all resource types excluding thermal power plants, this type of outage will be treated as any other forced outage.

Using a model that accounts for ambient temperatures, rather than relying on outage data alone, will help mitigate the effects of extreme weather events. The resource-level derating curves can then be used to calculate derations due to ambient temperatures based on historic, normalized, or forecast weather data. This will have the impact of adjusting the thermal derate to normalized base that is

[4] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

compatible with either resource accounting or resource modeling purposes. For example, unit capacity due to temperate impacts should also be reflective of peaks for a 1 in 2 weather year and not a 1 in 20 weather year.

Pairing Weather Data and Resources

Staff propose to match each thermal resource with the geographically nearest weather station that reports to the National Oceanic and Atmospheric Administration's (NOAA) Global Hourly Integrated Surface Database (ISD).[5] Staff will then retrieve the publicly available historic hourly dry-bulb temperatures from the ISD website and merge the data with curtailment data from CAISO.

Derate Curves

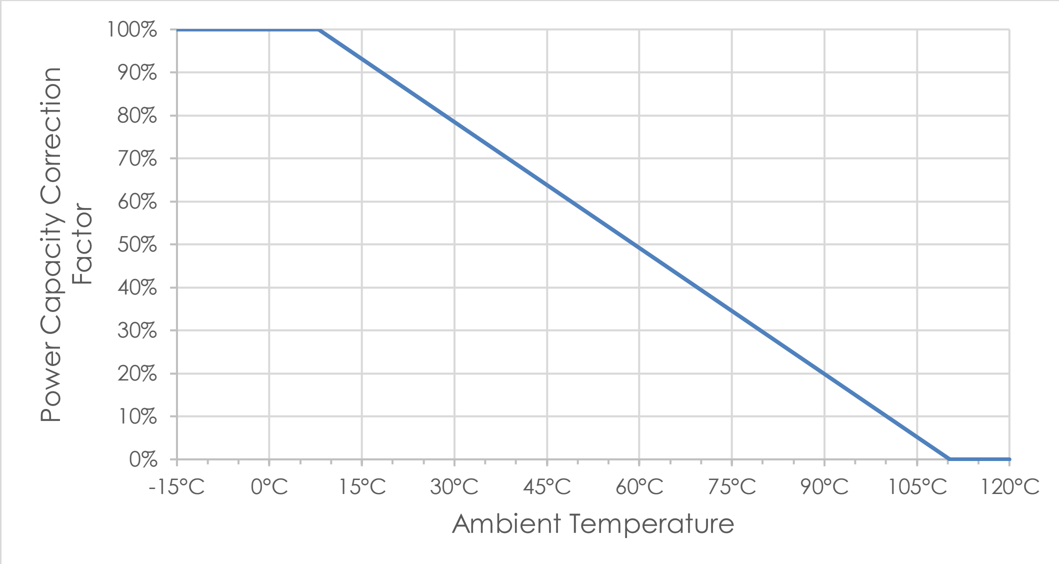
For thermal power plants, Staff propose defining resource-level derating curves based on a combination of prior curtailment reports and historic weather data. These curves will consist of a piecewise-linear function defined for all temperatures with three distinct regimes:

1. Full capacity (i.e., no deration) for low temperatures up to a specified cut-off temperature;
2. Linearly decreasing capacity with increasing temperature; and
3. Zero capacity above a very high temperature.

The slope of the second regime will be determined based on multilinear regression analyses performed on three prior years of historic curtailment and weather data for each resource type weighted by resource capacity but not by year. The cut-off temperature between the first and second regimes will be determined for each individual resource through a second set of linear analyses on the same curtailment and weather data sets, constraining the slopes to those determined in the multilinear analysis. The cut-off temperature for the third regime, determined by the slope in the second regime and the low-temperature cut-off, should be far above expected ambient temperatures, as indicated in the example depicted in Figure 1, and this regime ensures negative capacities are not possible.

[5] https://www.ncei.noaa.gov/products/land-based-station/integrated-surface-database

Figure 1: Example Deration Curve due to Ambient Temperatures for Thermal Power Plants



Because weather stations are not collocated with generation resources, onsite weather is not available. This methodology thus necessarily assumes that ambient temperatures at each resource is substantially correlated with temperatures at their selected weather stations. Since the same weather stations are used in the regression analyses to determine derating curves and for calculating derates, any constant offsets in temperature between the two locations due to, for example, differences in elevation, are cancelled out. While not perfect, we believe this approach provides a more reliable estimate of future derations due to ambient temperatures than by considering curtailment data independent of weather.

Capacity Accreditation

We propose to apply the resource-level derate curves to the current 30-year normalized weather data set for the purpose of capacity accreditation. This data set provides hourly temperatures for the weather stations available in NOAA's ISD. Each resource's hourly derations will thus be calculated by evaluating the value of the deration curve at each hour's temperature.

Loss-of-Load Expectation Modelling

Derations due to ambient temperatures for Loss-of-Load Expectation (LOLE) modelling will be calculated similar to capacity accreditation, simply substituting climate-informed forecast weather data sets in place of the normalized weather year.

Incorporating Derations due to Ambient Temperatures into UCAP

In either case of capacity accreditation or LOLE modelling, Staff propose to evaluate derations due to ambient temperatures on an hourly basis for one year, i.e., 8,760 hours in total. Each hourly deration value will included as the term $[Size\ of\ Reduction]_{r,h,i}$ where the index i corresponding to the nature-of-work code "AMBIENT_DUE_TO_TEMPERATURE" in the summation of EFD defined in Equation 1. Since EFOR is evaluated over the proposed three-year evaluation period, the single normalized or forecast weather year is effectively duplicated but the three years of historic curtailment and weather data are incorporated into the deration curves for each resource.

Alternative Methodology for Derations due to Ambient Temperatures

While Staff believe the methodology outlined in the previous sections is a viable approach and addresses concerns regarding the impacts of extraordinary weather events on resource availability, Staff may consider an alternative for resource counting. This alternative would treat forced outages due to ambient temperatures the same as all other forced outages, including the curtailment reports directly in evaluating Equation 1 rather than applying the resource-level deration curve to a normalized weather year. Were this approach taken, Staff would still propose using the deration curves with climate-informed forecast weather data for LOLE modelling. The main advantage of this approach is simplicity, and while qualifying capacities would be more sensitive to weather events, using the proposed seasonal and peak/off-peak aggregations in evaluating UCAP would help mitigate these impacts. The disadvantage of this proposal is that when an extreme hot weather event occurs the thermal derate would overstate the expected reduction of capacity when applied to a 1 in 2 weather year forecast.

UCAP Coordination with CAISO

ED Staff have been coordinating with CAISO staff and CAISO's Department of Market Monitoring throughout the past year to increase consistency between the organizations' approaches as both develop UCAP frameworks. Staff have worked with CAISO to identify publicly available data sets on which to base our respective UCAP formulations, and to select relevant records within CAISO's own curtailment data to incorporate into UCAP. While there are unique requirements for either organization, and important distinctions between the capacity accreditation and multi-year modeling processes, our goal has been to unify the UCAP frameworks to the greatest extent possible while accommodating the unique requirements.

Proposal 2. 2026 Planning Reserve Margin Price Mitigation Proposals

Background

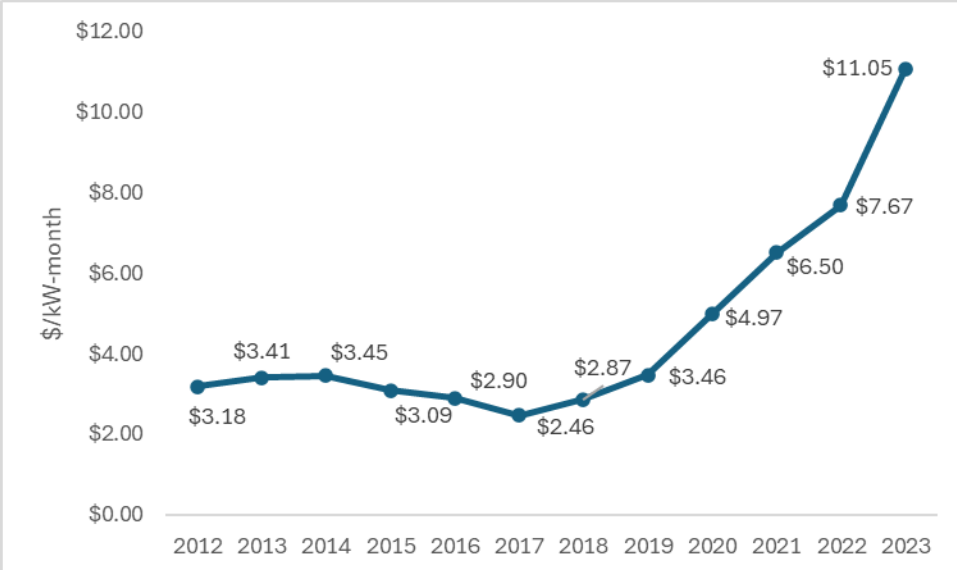
The Track 2 Decision (D.24-12-003) in the current Resource Adequacy (RA) Proceeding (R.23-10-011) deferred the adoption of the 2026 Planning Reserve Margin (PRM) to Track 3. On December 20, 2024, Energy Division Staff released its revised Loss of Load Expectation (LOLE) study results to inform the PRM for 2026. Results of the LOLE reliability analysis for the CAISO footprint show that all months have acceptable, i.e. minimal or zero, LOLE if each month is calibrated to a planning reserve margin of 21% for the months of October to March and 22.5% for the months of June to September. Months April and May showed a higher PRM of 24.5% resulting from higher variability of peak demands relative to the annual peaks, but these months continue to have lower absolute MW requirements, so reliability issues are not expected from those events. Staff recommended that April and May can also achieve an acceptable LOLE with a 21% PRM, the same as other off-peak months.[6] Within the study Staff put forward two PRM proposals aimed at balancing reliability and affordability goals – with one approach extending the effective PRM framework to compliance year 2026 and another approach utilizing temporary system waivers if certain requirements are met, including inability to procure below a certain price threshold. Herein these proposals are further developed and implementation details are discussed.

Adopting a PRM that is higher than the current 2025 17% PRM could potentially exacerbate market tightness, increase market power dynamics, and impact RA prices. Notably, as shown in Figure 2 below, between 2017 and 2023 the weighted average price for RA capacity has increased by 349% from $2.46/kW-month to $11.05/kW-month.[7] Data collected from Quarter 1 through 3 for 2024 shows price trends continue to increase, with preliminary results showing a weighted average price of $19.28/kW-month (noting that Q4 data is still be collected which will modify the final price). The prices referenced in Figure 2 reflect contracts executed in the relevant compliance year and the year prior (e.g., 2023 data include contracts executed in 2022 and 2023 that are delivered in 2023). Additionally, the RA price data set is only inclusive of reported RA-only capacity contracts. Specifically, the RA price data does not include RA contracts with energy dispatch rights (i.e. tolling agreements, RA with energy settlements) or renewable portfolio standards contracts (i.e. contracts that include renewable energy credit (REC), energy, and capacity benefits).

[6] Appendix B to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis. Dec. 20, 2024

[7] 2017 – 2022 Resource Adequacy Reports (Table 6), along with internal analysis of 2023 RA price data that will inform the 2023 RA Report. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage

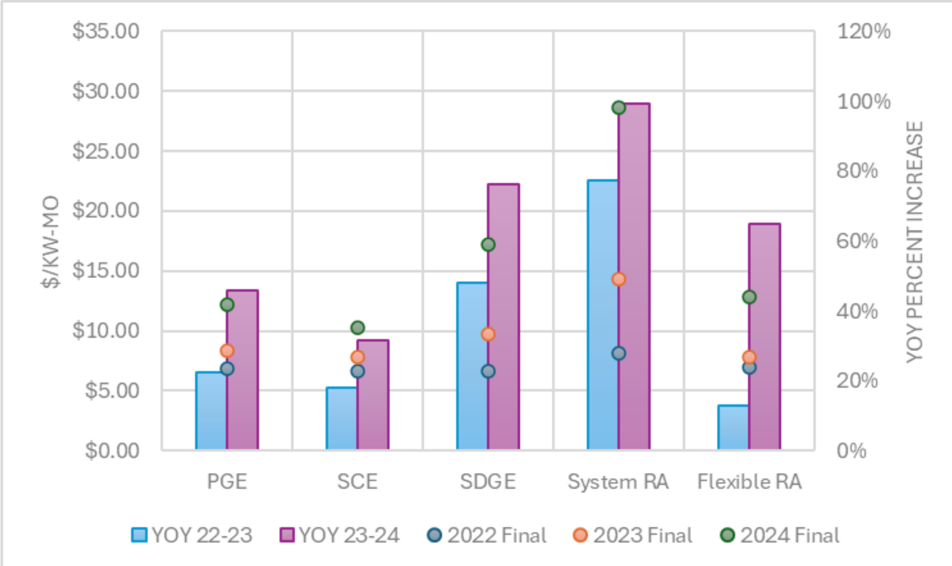
Figure 2 - Weighted Average Capacity Price ($/kW-month) by Compliance Year (2012-2023)



Another reference point for price trends is the most recent Power Charge Indifference Adjustment (PCIA) RA market price benchmark data that shows System RA prices between 2023 and 2024 have nearly doubled, increasing from $14.37 to $26.26/kW-month.[8] Figure 3 below shows year-over-year PCIA price changes as a percent (shown as bars that correspond to the right y-axis), as well as weighted average prices for local, system, and flexible RA (shown as circles that correspond to the left y-axis) between 2022 to 2024. Also of concern to Energy Division is some LSEs have indicated that in recent procurement solicitations, generators are offering multi-year contracts that would lock in these high prices for the mid-term time horizon, most notably for existing capacity in exceedance of going forward fixed costs. With these price concerns in mind, Staff believes it's prudent and necessary to discuss reliability planning (PRM study results and increases to the RA program PRM for CPUC jurisdictional LSEs) in the context of price impacts and balancing affordability goals.

[8] PCIA Market Price Benchmarks sent to the PCIA service list, R. 17-06-026, on November 5, 2024, which revised the MPBs to a weighted average System RA price of $26.26/kW-month.

Figure 3 - PCIA RA Market Price Benchmarks ($/kW-month) 2022 through 2024



In addition to increases in price, there is also the impact of increased demand for capacity associated with load The latest draft California Energy Commission (CEC) demand forecast from the 2024 Integrated Energy Policy Report (IEPR) shows an increase in peak demand for 2026 when compared to the 2025 demand forecast from the 2023 IEPR process.[9] Table 1 below reflects that the CAISO peak coincident demand forecast for August and September is forecasted to increase by about 600 MW or ~1.3%. The additional need for capacity to meet the forecasted load growth coupled with higher PRM levels could exacerbate an already tight capacity market.

[9] The source of the data is the CEC's IEPR forecast. The "monthly_peak_days" tab, filtered for the planning scenario and coincident peak load was used from the CED 2024 Peak Load Forecast and the CED 2023 Peak Load Forecast Corrected.

Table 1

Change in Load Forecast from 2025 to 2026
MW Difference from 2025 (2023 IERP) to 2026 (2024 IERP)
Monthly Peak (PST)*

Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO	690	783	1,240	1,141	(2,480)	(364)	(107)	607	609	1,099	1,002	705
PG&E Area	685	389	719	616	(245)	(604)	(978)	(1,946)	(276)	245	627	346
SCE Area	66	388	416	496	(2,489)	148	708	2,381	483	655	435	377
SDG&E Area	(99)	5	10	(97)	9	62	283	769	264	315	(45)	23

% Difference from 2025 (2023 IERP) to 2026 (2024 IERP)

Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO	2.3%	2.7%	4.3%	3.7%	-7.1%	-0.9%	-0.2%	1.3%	1.3%	2.9%	3.2%	2.3%
PG&E Area	5.2%	3.0%	5.5%	4.4%	-1.5%	-3.0%	-4.6%	-9.5%	-1.4%	1.5%	4.7%	2.5%
SCE Area	0.5%	3.0%	3.1%	3.5%	-15.6%	0.8%	3.2%	11.3%	2.1%	3.6%	3.0%	2.8%
SDG&E Area	-3.3%	0.2%	0.4%	-3.4%	0.3%	2.0%	8.1%	22.5%	6.4%	8.9%	-1.4%	0.8%

*Note: The time of the monthly peak can vary by month and by forecast vintage.

Proposal A: 17% PRM RA Requirement paired with effective PRM (extending the 2025 status quo)

- Adopt 17% PRM for RA compliance year 2026
- Extend effective PRM framework with Invested-Owned Utilities (IOUs) procuring a MW amount equivalent to the 22.5% PRM LOLE study results

Energy Division Staff proposes adopting a 17% PRM and extending the effective PRM framework through RA compliance year 2026. This approach follows course with D.23-06-029 which extended the effective PRM through 2025. Staff proposes that a 17% PRM would continue in 2026 and, to address higher reliability needs, the effective PRM framework would be extended with IOUs procuring a non-binding MW amount in peak months (June – September) equal to the difference between the modeled LOLE results and the adopted PRM. For example, with an adopted PRM of 17% and the modeled PRM at 22.5%, the effective PRM would be a MW procurement target roughly equivalent to 5.5% of the 2026 CPUC-jurisdictional September peak load forecast.

Following the approach used in D.21-12-015 the procurement targets for the effective PRM would be calculated as follows. The 2026 California Energy Commission's (CEC) peak demand forecast for the CAISO TAC area is 46,345 MW and, based on load share ratios provided by the CEC for the present year, the CPUC-jurisdictional load share of the CAISO TAC is approximately 90%.[10] Therefore, an effective PRM of 5.5% would result in approximately 2,300 MW of additional procurement. The total effective PRM procurement value would then be allocated to each IOU based on the Transmission Access Charge (TAC) area CAISO load share for each utility service territory. Using CEC 2023 Baseline LSE and BAA data, the

[10] California Energy Demand (CED) 2023 Peak Forecast – Corrected. Monthly Peak forecast for CAISO TAC 2026 planning scenario. https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2. CPUC-jurisdictional load share based on 2025 load share data provided by CEC.

approximate allocations would be the following: 1,005 MW for PG&E, 1,065 MW for SCE, and 230 MW for SDG&E.[11]

Staff proposes slight modifications to the existing effective PRM framework adopted in D.23-06-029. Under the existing framework the effective PRM includes June through October, however Staff proposes that the effective PRM for RA compliance year 2026 would only include June through September. This adjustment is influenced by the results of the latest LOLE study which identified June through September as the months with the highest PRM requirements, i.e., 22.5% compared to 21% in other months. Another caveat is regarding the Emergency Load Reduction Program (ELRP) resources that are currently eligible to count towards the effective PRM. Staff supports both RA and non-RA eligible resources to count towards the effective PRM as was previously adopted in D.21-12-015, however the residential ELRP (Power Saver Rewards) resources are only authorized through the end of 2025. Staff clarifies that adopting an effective PRM for the 2026 RA compliance year would not be determinative of whether certain ELRP resources continue as contingency resources beyond 2025.

Retaining the effective PRM will provide reliability benefits beyond the adopted PRM and can be a lower-cost procurement option since it allows resources to be contracted that don't meet typical RA-eligibility requirements (such as imports procured after the RA showing date and firm energy call-options from co-generation facilities). Under the effective PRM framework IOUs procure eligible resources and costs associated with resources in excess of an IOU's own PRM requirements are charged to benefiting customers in the IOU's service territory via the Cost Allocation Mechanism (CAM).

The Commission could further refine the eligible resources allowed to count towards the effective PRM. One of the key resources that has been used by utilities, to provide additional reliability, is non-RA eligible resources. While some non-RA eligible resources do support reliability (e.g. a resource that comes online mid-month is ineligible for RA but it provides reliability if it is participating in the market), some resource may have more limited reliability benefits, for example, imports. The Commission could consider whether there should be any restrictions on the eligible resource types that can count towards the effective PRM.

Proposal B: 22.5% PRM RA Requirement and Temporary System Waiver

- Adopt PRM results from LOLE study for RA compliance year 2026
- Allows LSEs to request temporary System Waivers in peak months (June – Sept.) for RA Requirements above 17% if certain criteria described below are met
- CAISO Capacity Procurement Mechanism (CPM) backstops RA deficiencies with procurement costs paid by LSEs with deficiencies

[11] California Energy Demand (CED) 2023 Baseline LSE and BAA Tables. Form 1.5b. Totaling the forecast for each TAC Staff finds that the load share ratios are: 43.7% for PG&E, 46.3% for SCE, and 9.9% for SDG&E. https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2

Informed by the results of the latest LOLE study, Energy Division Staff (ED Staff) proposes adopting a 21% PRM for the months of October to May and a 22.5% PRM for the months of June to September for RA compliance year 2026.

Staff proposes allowing LSEs to request a temporary System Waiver for RA requirements above their 17% PRM if certain criterion are met, including the inability to procure capacity to meet their remaining PRM requirement below an established price threshold. To be eligible for the waiver, LSEs must demonstrate that they have made all commercially reasonable efforts to procure resources to meet their requirements, including a requirement that they issue Request for Offers (RFOs), bid into other market participant RFOs, and other means of bilaterally procuring capacity. Reasonable procurement efforts would need to reflect efforts made after the date of a formal Commission decision on this proposal. Under this proposal LSEs must procure up to at least a 17% PRM and waivers would only be considered for requirements above 17%. Waiver requests would only be allowed in peak months (June – September), due to tighter system capacity conditions. The duration of the temporary system waivers would extend to compliance year 2026 and 2027 only. Energy Division Staff will conduct another LOLE study for compliance year 2028 and any considerations for system waivers should not extend beyond 2028 until results of that study are published.

Determining an appropriate price threshold for waiver eligibility is consequential and paramount to the effectiveness of the waivers. One option could be to use the CAISO's Capacity Procurement Mechanism soft-offer cap, which is currently $7.34/kW-month, as a trigger price for waiver eligibility.[12] Another option that ED Staff proposes is establishing a price threshold for waiver eligibility based on the RA penalty structure. D.20-06-031 modified the previous RA Penalty price of $6.66/kW-month ($79.92/kW-year) to a seasonal framework where summer months (May – October) have a penalty price of $8.88/kW-month and non-summer months have a penalty price of $4.44/kW-month. Within these modifications the total penalty price of $79.92/kW-year remained the same. A driving force behind these changes was the recognition that prices for RA products vary significantly in peak summer months, compared to non-summer months, due to higher RA obligations and more limited supply. Here Staff proposes that the total summer RA penalty price ($53.28-kW for six months) could be weighted by the 2026 monthly peak forecast to establish a price threshold for waiver eligibility.

To arrive at the proposed price thresholds for waiver eligibility for June – September Staff took a weighted average approach, and results are presented in Table 2 below. Beginning with the 2026 monthly peak forecast from the 2023 Integrated Energy Policy Report (IEPR), Staff calculated the *Percent of Seasonal Total (May – Oct.)* by dividing the monthly *Managed Peak Forecast* by the sum of the May through October *Managed Peak Forecast.* For example, the June value of 0.1681 is calculated as 42,427 MW / 252,452 MW. The *Proposed Price Threshold ($/kW-month)* is calculated by multiplying the *Percent of Seasonal Total* by the total RA penalty price for summer months ($53.28). Continuing with the June example, June's proposed price threshold of $8.95/kW-month is calculated by multiplying 0.1681 by $53.28. As noted in Table 2, waiver eligibility would only be permitted in June – September. Although this differs from the summer months defined by the RA penalty structure (May – October), it better

[12] CAISO Capacity Procurement Mechanism Enhancements 5/17/2024. https://www.caiso.com/notices/capacity-procurement-mechanism-enhancements-track-2-cpm-soft-offer-cap-effective-date-6-1-24

aligns with the higher forecasted months and the months with the highest PRM requirements identified in the LOLE study.

Table 2: ED Staff's calculations for proposed price thresholds for waiver eligibility[13]

Month	2026 CAISO Managed Peak Forecast	Percent of Seasonal Total (May - Oct.)	Proposed Price Threshold ($/kW-month)
5	34,512	0.1367	$ 7.28
6	42,427	0.1681	$ 8.95
7	46,327	0.1835	$ 9.78
8	45,154	0.1789	$ 9.53
9	46,345	0.1836	$ 9.78
10	37,687	0.1493	$ 7.95
Total	252,452	1	$ 53.28
Waiver requests only allowed in June - September			

Similar to the existing Local Waiver process, waiver requests would have to demonstrate that the LSE actively sought products and received bids (as evident by the results of their Request for Offers) with prices in excess of the administratively determined price threshold or received no or insufficient bid volumes to meet the incremental requirements. LSEs would need to show that they exhausted all commercially reasonable efforts which include holding, participating in RFOs and utilizing broker markets. The waiver would only apply to Commission-imposed penalties; a deficient LSE would be responsible for any applicable backstop procurement costs even if it received a waiver from CPUC RA penalties. The process for requesting a system waiver could follow the existing local waiver process where LSEs submit requests via a Tier 2 Advice Letter (AL) and circulate the public version of the AL to the service list of the current RA proceeding. The existing local waiver request process was adopted in D.19-06-026 to increase the transparency of waiver requests and make the information more easily accessible; previously this data was made available through California Public Records Act request, or by Staff on the CPUC website. Another consideration, however, is the timeliness of processing requests and the administrative burden that comes with processing these requests. Under the current process, resolving requests can take a significant amount of time depending on the amount of time required for staff to process the initial request and resolve any subsequent protests. To expedite processing requests, an alternative approach to the Tier 2 Advice Letter process would be to process waiver requests though Energy Division letters, as it was done for local waivers before D.19-06-026 adopted an AL process. Staff encourages input from parties on which process would be preferred.

The benefits of Proposal B are the higher reliability requirements – with a 22.5% PRM for June to September and a 21% PRM for October to May – and the inclusion of a price mitigation mechanism by allowing for system waivers above a specified price threshold (e.g., CAISO CPM soft-offer cap of $7.34/ kW-month or based on the RA penalty price of $8.88/kW-month). Additionally, by adopting a higher

[13] 2026 peak forecast from California Energy Demand (CED) 2023 Peak Forecast – Corrected. Monthly Peaks planning scenario for CAISO TAC. https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2

PRM, the CAISO has a greater ability to address individual LSE reliability needs up to the higher PRM levels, since authority to procure resources through the Capacity Procurement Mechanism (CPM) is limited up to the adopted Local Regulatory Authority PRM level.

There are shortcomings to this proposal that also need to be considered. Pursuing resources through the CPM runs the risk that resources may not accept a CPM designation or be available to the CPM process, as they are committed to other balancing authorities. This could result in CAISO not fulfilling the full amount of its solicitation. Another consideration involves cost-equity. CAISO may not choose to CPM for all deficient LSEs; this would result in some LSEs paying more for reliability than others where backstop isn't issued. For example, an LSE that procures 22.5% PRM will pay for more reliability resources than an LSE that procures only to a 17% PRM in the event that a CPM is not ordered. Also, an LSE that procures to 22.5% will pay for more resources if a collective deficiency CPM (rather than an individual LSE deficiency CPM) is triggered and the costs are spread to all LSEs. The Commission considered proposals for temporary systems waivers to address tight market conditions in D.19-06-026, D.20-06-031, and D.24-06-004. Ultimately, in these decisions, the Commission declined to adopt system waiver proposals stating that concerns about reliability, unintended market power, and LSEs leaning on other LSEs' procurement had not yet been resolved. ED Staff puts forward a proposal for temporary system waivers in hopes that robust discussions can address unresolved issues.

(END OF ATTACHMENT A)