APPENDIX A

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California Public Utilities Commission

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Energy Division Study for Proceeding R.21-10-002

Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024

Table of Contents

List of Acronyms

AAEE – Additional Achievable Energy Efficiency	LOLH – Loss of Load Hours
BAA – Balancing Authority Area	MW – Megawatt
BTM PV – Behind the Meter Photovoltaic	NQC – Net Qualifying Capacity
CAISO – California ISO	PRM – Planning Reserve Margin
CEC – California Energy Commission	PU Code – Public Utilities Code
ELCC – Effective Load Carrying Capability	RA – Resource Adequacy
EUE – Expected Unserved Energy	RPS – Renewables Portfolio Standard
IEPR – Integrated Energy Policy Report	SERVM – Strategic Energy Risk Valuation Model
LCR – Local Capacity Requirements	TAC – Transmission Access Control
LOLE – Loss of Load Expectation	UCAP – Unforced Capacity
LSE – Load Serving Entity	WECC – Western Electric Coordinating Council

1. Introduction

Consistent with D.20-06-031 and D.21-06-029, this puts forward the assumptions and results of Energy Division's 2024 Loss of Load Expectation (LOLE) and Effective Load Carrying Capability (ELCC) studies for party comment and CPUC consideration. These studies are meant to complement prior CPUC work performed for the Integrated Resource Planning Proceeding (IRP) in R.20-05-003. This report provides study results at a monthly level to mirror the current monthly Resource Adequacy (RA) construct, in contrast to the annual results presented in the IRP Proceeding.

The current RA proceeding, R.21-10-002, seeks to examine the overall RA capacity structure as part of the reform track of the proceeding.[1] With this objective in mind, staff performed Loss of Load Expectation (LOLE) and Effective Load Carrying Capability (ELCC) analysis for RA compliance year 2024 to assess the adequacy of the current 15% Planning Reserve Margin (PRM) used to set RA obligations. Staff chose 2024 because it aligns with the RA reform implementation timeline and would allow additional time to thoroughly consider the results, to determine whether this approach can work in conjunction with RA reform, and, if necessary, to allow for load serving entities (LSEs) to modify their portfolio positions in light of these results and/or RA reform more broadly.

To this end, the results of the studies should primarily be utilized by parties to assist in further thinking around a slice-of-day reliability framework being developed in the RA Reform Track of this proceeding. Setting PRM and ELCC values based on a LOLE study like this would constitute an integrated framework for reliability analysis. The results should also be used to help guide discussions regarding what assumptions should be utilized in setting PRM levels beginning with the 2024 RA compliance year, refreshing ELCC values for wind and solar beginning with the 2023 RA compliance year, and thinking about ELCC values for storage, hybrid, solar and wind in 2024 and beyond.

In addition, we note that the study results are broadly consistent with recent mid-term reliability analysis performed by the California Energy Commission (CEC), which concluded that procurement ordered in the IRP Mid Term Reliability (MTR) Decision (D.21-06-035) appears sufficient to meet a 1 day in 10-year loss of load expectation (LOLE) target, indicating adequate system reliability for 2024.[2] However, for purposes of this study, Energy Division staff assumed a high penetration of variable and use-limited resources and removed Diablo Canyon and some cogeneration resources from the system in order to surface LOLE events and test the reliability contribution of different resource types through an ELCC study. This portfolio may not be exactly consistent with what the CEC assumed in its analysis. Assuming a higher penetration of variable and use-limited resources in the system results in lower average ELCC values due to saturation effects.

2. Summary of Draft Study Results

The results of the LOLE and ELCC studies are provided at a monthly level to mirror the current monthly RA construct. The results also reflect the impacts of accounting for forced outages and planned

[1] December 2, 2021 Scoping memo linked here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M428/K181/428181323.PDF
2 Midterm Reliability Analysis (ca.gov)

maintenance in the PRM. Forced outages are currently not accounted for in Net Qualifying Capacity (NQC) determination, however if a generator does not have its NQC set by ELCC or historical performance, then the CPUC should consider whether it is appropriate to include forced outages in the NQC value of the resource. (Unforced Capacity (UCAP))

Table 1 shows the monthly PRM expressed as both a required effective capacity MW amount and a percentage of peak demand. The PRM is shown under two frameworks:

1. Current NQC counting for most types of resources, with new portfolio ELCCs that set the effective capacity for wind, solar, storage, and hybrid resources, and
2. Current NQC counting with forced outage derates (applied to resources whose NQC is not determined by historical performance or ELCC), plus new portfolio ELCCs that set the effective capacity for wind, solar, storage, and hybrid resources.

In both frameworks, planned maintenance outages are also deducted from the total effective capacity requirement. Accounting for forced outages via UCAP NQC translates to a monthly 2.5-4.5% reduction in PRM (depending on the month). Using the new portfolio ELCCs, but not accounting for forced outages via UCAP NQC, the PRM ranges between 19 and 21 percent in the peak months (July through September). When accounting for forced outages via UCAP NQC, the PRM ranges between 16 and 17 percent in the same months.

Table 1: Summary of monthly effective capacity requirements and PRM

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Effective Capacity: NQC current, new Portfolio ELCC	39,573	40,471	38,118	36,281	39,299	48,865	56,593	55,362	52,098	43,161	40,058	39,419
Effective Capacity: NQC current, UCAP, new Portfolio ELCC	38,063	39,119	36,981	35,391	38,431	47,791	55,050	53,784	50,646	41,881	38,625	37,956
Planned Outages Removal	0	154	564	416	15	137	0	0	0	0	0	0
Planned Outages Removal, UCAP	0	143	527	390	14	130	0	0	0	0	0	0
SERVM Sales Peak	33,364	31,957	31,341	32,502	35,180	44,089	47,253	46,380	43,152	36,452	33,359	34,018
PRM, NQC current, new portfolio ELCC	19%	26%	20%	10%	12%	11%	20%	19%	21%	18%	20%	16%
PRM, NQC current, UCAP, new portfolio ELCC	14%	22%	16%	8%	9%	8%	16%	16%	17%	15%	16%	12%

In the summary table above, the median monthly peaks (annualized such that the median annual peak and highest median monthly peak match) in SERVM are used as the denominator in the PRM determination rather than the monthly sales peaks provided by the 2020 IEPR demand forecast. This was done to keep the entire analysis internally consistent because the (stochastic) monthly distribution of peaks in SERVM is different than the deterministic monthly peaks provided with the 2020 IEPR.

For the PRM determination, the 2024 RA study year model was ultimately calibrated to result in a probability-weighted average LOLE of 0.16 total across all 12 months of the year, with 0.13 LOLE concentrated in the peak months of June through September. For calibration to the desired monthly LOLE targets, staff removed the existing capacity summarized in Table 4, which includes one unit of Diablo Canyon Nuclear Power plant and the cogeneration fleet. An important takeaway is that in the modeled 2024 system, CAISO relies heavily on large amounts of storage and solar that are under development (as shown in Table 5).

Table 12 and Table 13 present monthly portfolio and resource technology specific ELCC results for the 2024 Base Portfolio, expressed in MW of effective capacity and percent of installed capacity. Relative to previous Energy Division ELCC studies, there is a significant decrease in the average ELCC percent value of the portfolio of resources in the study (solar, wind, battery and pumped storage, and hybrid resources), primarily attributable to the higher penetrations of resources in the study portfolio. Table 14 through Table 19 reflect alternate scenarios of portfolio size and resource composition and their consequent impact on average ELCCs.

3. Background

Decision (D).05-10-042 adopted a monthly Resource Adequacy (RA) program that required Load Serving Entities (LSEs) to sign contracts with suppliers of RA capacity that commit net qualifying capacity (NQC in MW) to the California Independent System Operator (CAISO) market each month totaling their calculated share of the monthly coincident peak load plus a Planning Reserve Margin (PRM) of 15 percent. The supplier then confirms that contract to the CAISO, resulting in the supplier having a Must Offer Obligation (MOO) into CAISO energy markets which requires the resource to bid or self-schedule into CAISO's energy markets.

In recent years, the electric grid has been impacted by a rapidly changing generation fleet that includes a dramatic increase in variable generation from wind and solar power, significant demand side programs such as Behind the Meter (BTM) solar, energy efficiency, electric vehicles, and other programs and skyrocketing battery storage investments. In addition, variability in electric demand patterns related both to climate change as well as economic and demographic changes, a move to protect higher levels of reserves (6% operating reserves in addition to firm demand) and increased variability around net peak versus gross peak demand require a reevaluation of adequate effective capacity needed to protect reliability. These transformations to the electric market, both on the demand side and supply side, have impacted how RA obligations are determined, the efficacy of past methods (such as the 15% PRM) and general conceptions about what time of the day is the most critical for electric reliability. All this has had significant impacts on the use of the residual electric generation fleet, as it transitions to a balancing and integration role in lieu of a primary energy production role. Both the level of adequate effective resources needed as well as the evolving ability of certain types of resources to provide effective reliability contribution are changing as the overall grid changes.

Calculating a resource's NQC is a two-step process, beginning with the calculation of a resource's Qualifying Capacity (QC) MW values. QC is calculated based on the generator's technology and past performance. Second, the QC is capped at the amount of MWs deliverable to the aggregate of CAISO load, resulting in Net Qualifying Capacity (NQC). A generator can be fully deliverable, meaning their QC MW may count fully towards RA obligations, or it can be Energy Only (meaning not deliverable at all, and NQC is 0) or Partially Deliverable (meaning NQC is somewhere between 0 and the full QC MW of the generator). The CAISO regularly conducts studies to determine how much of a resource's capacity is deliverable. Deliverability studies are meant to ensure that if RA capacity resources are available and called on, their ability to provide energy to the system at peak load should not be limited by the dispatch of other capacity resources in the vicinity. In actual operating conditions, energy-only resources may displace RA resources in the market's economic dispatch that serves load.

To deal with the dramatic growth of variable or energy limited resources such as wind, solar and now battery storage interconnected to the electric grid, the CPUC was ordered in PU Code 399.26(d) to use ELCC studies to set the QC of wind and solar resources. Through a series of ELCC studies, it is possible to determine the effectiveness of a resource or group of resources at contributing to a targeted level of reliability relative to an ideal generator. Since 2017, staff has performed LOLE and ELCC studies and the ELCC values (but not the LOLE reliability targets) have been adopted in the RA proceeding. The most recent set of ELCC values was adopted in 2019, whereas the LOLE study that was used to set the currently adopted PRM was conducted in 2004.

In Track 2 of the previous RA proceeding, R.19-11-009, SDG&E proposed that the Commission review the 15% PRM, noting that the PRM was adopted in D.04-10-050 and many of the inputs that went into setting the PRM are dated and should be reexamined. SDG&E specifically proposed that a LOLE study be conducted to support a review of the PRM in Track 3B.2 of the RA proceeding. In response to SDGE's proposal the Commission determined that "[g]iven the extensive changes to the grid and the mix of generating resources since the issuance of D.04-10-050, the Commission concurs that it is appropriate to begin review of the PRM and finds SDG&E's proposal for a LOLE study appropriate to support that process. To that end, we authorize Energy Division to facilitate a working group to develop a set of assumptions for use in the LOLE study and Energy Division shall perform the LOLE study. The LOLE study shall be submitted into the proceeding and parties will have an opportunity to comment."[3]

4. Model Inputs and Conventions

Aggregate system reliability is measured by a stochastic model that analyzes generation and electric demand patterns for each hour over thousands of individual simulations that together calculate a probability weighted expected average across all scenarios simulated. Reliability metrics from stochastic reliability modeling include LOLE as well as Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH).[4] Contribution to reliability is measured in terms of ability to reduce LOLE or EUE by adding resources then rerunning the analysis.

[3] D.20-06-031 at p. 21, OP 9

[4] LOLE equals the expected number of loss-of-load events, regardless of length, in a given year. LOLH equals the expected number of hours with loss-of-load in a year. EUE equals the total MWh of unserved energy in a year. LOLE is a measure of frequency, not duration or magnitude. LOLH is a measure of duration, not frequency or magnitude. EUE is a measure of magnitude, not frequency or duration.

For this analysis, staff used a 0.1 LOLE target (equivalent to one loss-of-load event every ten years) to determine the level of RA resources needed for adequate system reliability. The 0.1 LOLE target, although not officially adopted by the Commission, is in common use around the country and in past LOLE studies performed for CPUC proceedings, including the RA and IRP proceedings.

Staff used the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrapé Consulting. SERVM is a probabilistic system reliability planning and production cost model. Staff configured SERVM to analyze a target study year (2024) under a range of uncertainty including weather conditions (20 historical weather years), economic output (5 weighted levels), and unit performance (50 independent annual draws). SERVM simulates hourly economic unit commitment including reserves and dispatch for individual generating units over all 8,760 hours of the study year. The model represents the entire Western Interconnect using a zonal representation of the transmission system, grouped into eight zones for California and 16 for the rest of the Western Interconnect, roughly equating to actual Balancing Area boundaries.

Model Inputs

Staff sourced the inputs and assumptions from the IRP proceeding (R.20-05-003), specifically the Preferred System Plan (PSP) modeling work conducted by staff in Q4, 2021, and described in the Proposed Decision Adopting 2021 Preferred System Plan[5] issued on December 22, 2021.

The IRP PSP dataset included three major parts: the electric demand forecast, baseline (i.e., existing) electric generation resources, and new electric generation resources projected to be built.

The electric demand forecast was the California Energy Commission's (CEC) adopted 2020 California Electricity Demand Forecast Update,[6] which is often referred to as the 2020 Integrated Energy Policy Report (IEPR) demand forecast. Following the assumptions used for the IRP's PSP, staff specifically used the Mid-Mid Managed Forecast for 2024 but paired with the High Electric Vehicle demand forecast (rather than Mid).

The 2020 IEPR demand forecast includes an annual peak and energy forecast for California and the balancing areas within. It also includes hourly profiles for the TAC areas that comprise the CAISO balancing area for each year of the forecast, disaggregated into consumption demand and several demand modifiers. Staff used the annual peak and energy forecast to size SERVM's 20 historical year (1998-2017) set of weather-normalized consumption demand shapes. Staff did not use the IEPR demand forecast's hourly consumption profiles because they are only a single average year, rather than a multiple weather year distribution. Staff did use the demand modifier profiles for Additional Achievable Energy Efficiency (AAEE), Light and Heavy Duty Electric Vehicles (EVs), and Time-Of-Use (TOU) rate impacts that are included with the IEPR because those demand modifiers are assumed weather independent and can be paired with any of the 20 weather year consumption profiles. For BTM PV staff used its 20 historical year set of solar shapes, sized to the BTM PV energy production forecasted in the IEPR. For BTM battery storage, staff backed out its impact on the IEPR annual peak and energy forecast

[5] https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=434547053

[6] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update-0

and then modeled it like a dispatchable utility-scale battery storage unit, but with 2.5 hour duration to maintain consistency with the IRP PSP assumption.

The demand side resources forecasted in the IEPR have clearly shifted the distribution of the hour of day when peak demand occurs, especially in summer months. This is captured in the LOLE and ELCC analysis results in this report and manifests as resources that are use-limited or unable to generate during evening peak hours are less able to reduce LOLE and hence have lower ELCC. The shift in hour of peak is shown in Figure 1 and Figure 2 below by comparing SERVM's 20 weather year distribution of monthly peak hours without and with demand modifiers. Each block in the figures indicates the number of years out of the 20 year distribution that the monthly peak occurs at the hour indicated in the left column. While peak hours tend to be later in the evening in the winter, the net effects of demand modifiers are most significant during the summer. It is clear from a comparison of the two figures that consumption before taking into account demand modifiers peaks between HE16 (3 pm) and HE18 (5 pm) during the summer, and demand modifiers (including significant Behind the Meter PV) move the peak hours to between HE18 (5 pm) and HE20 (7 pm) in the summer.

The peak hour net of supply side wind and solar generation (the so called "net peak," which is not illustrated in Figure 1 and Figure 2 below) moves even further into the evening during the summer. Moving "net peak" later causes LOLE events to move later in the evening. This finding is confirmed by Figure 6, which illustrates the majority of LOLE hours occurring around the "net peak" hours (HE20 (7 pm) or later) during the summer rather than at the summer sales peak hours generally between HE18 and HE 20.

Figure 1: 20 weather year distribution of consumption peak hour (i.e., no demand modifiers), by month

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
13	0	0	1	5	0	0	0	0	0	0	0	0
14	0	0	0	5	6	0	0	0	0	4	0	0
15	0	0	0	0	5	0	2	1	10	15	0	0
16	0	0	0	0	3	10	6	13	10	0	0	0
17	0	0	0	3	6	10	12	6	0	0	0	0
18	0	0	0	0	0	0	0	0	0	1	2	0
19	20	20	0	0	0	0	0	0	0	0	18	20
20	0	0	19	7	0	0	0	0	0	0	0	0

Figure 2: 20 weather year distribution of sales peak hour (i.e., net of demand modifiers), by month

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	1	0	0	1	0	0	0
17	0	0	0	0	0	4	7	6	2	0	0	0
18	0	0	0	0	0	8	13	12	5	6	1	0
19	20	20	0	0	0	2	0	2	12	14	19	20
20	0	0	20	20	20	5	0	0	0	0	0	0

For demand forecast assumptions outside of California, staff used the information included in the WECC

2028 Anchor Data Set.[7]

Assumptions for baseline and new electric generation resources operating across the Western Electricity Coordinating Council (WECC) region were drawn from multiple sources. For existing generators operating within the CAISO balancing area, staff used the confidential CAISO Masterfile which lists operating parameters for all generators serving CAISO's electric market. For existing and new generators outside the CAISO balancing area, all generation information including max capacity, online dates and operating parameters, was drawn from the WECC 2028 Anchor Data Set. Staff did not update to the newer 2030 ADS yet but plans to with the next major modeling inputs overhaul expected to occur within the IRP proceeding in 2022.

Projections for new planned and in development resources to serve CAISO demand were compiled from LSE IRP filings (filed on September 1, 2020, and subsequently updated by LSEs and CAISO multiple times in 2021), resource procurement ordered in the IRP Mid-Term Reliability Decision (D.21-06-035)[8], and capacity expansion modeling using the IRP proceeding's RESOLVE model.[9] A complete list of generation resources assumed in the studies along with other key input data are available on the CPUC's website.[10]

Key Modeling Conventions

Staff used several key constraints and modeling conventions for this analysis:

- Staff used an annual LOLE target of 0.1 as the threshold for adequate system reliability. To produce monthly LOLE, ELCC, and PRM results, the 0.1 LOLE target was spread across all 12 months of the year. Staff targeted a higher LOLE in the peak months of June through September (targeting a range of 0.02 to 0.03 LOLE each month) and surfaced de minimis LOLE in the other eight months of the year (targeting a range of 0.000 to 0.005 LOLE each month) while attempting to keep the sum of all months' LOLE to be about 0.1 LOLE.
- Staff defined a loss-of-load event as an instance when available resources total 106 percent of hourly electric demand or less. Three percent spinning reserves and three percent regulation up reserves comprise the six percent of hourly electric demand amount of reserves that must be maintained at all times to avoid shedding load.
- Staff modeled targets for regulation down, non-spinning reserves, load following, and frequency response. However, lack of these types of reserves in any given hour did not necessarily translate to a loss-of-load event. This is broadly consistent with CPUC production cost modeling guidelines released in 2019 which described among other things the definition of a loss-of-load event relative to mandatory and protected levels of operating reserves.[11]

[7] The 2028 WECC Anchor Data Set Phase 2 V2.0 can be downloaded from this page: https://www.wecc.org/SystemStabilityPlanning/Pages/AnchorDataSet.aspx
[8] https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=389603637
[9] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials
[10] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2021
[11] CPUC production simulation modeling guidelines including a definition of Loss of Load event were published to the CPUC website on March 29, 2019

- Staff implemented a 4,000 MW peak import constraint in HE 17-22 in all 12 months of the year, further restricting imports relative to the IRP Preferred System Plan assumption of applying the 4,000 MW peak import constraint only in the peak months of June through September.
- SERVM models monthly planned maintenance and forced outages on generators given an annual amount of required maintenance outage time and distributions of forced outage events. Staff used Generator Availability Data Set (GADS) outage data from the North American Electric Reliability Corporation (NERC) as the source for these inputs. SERVM allocates required planned maintenance across the months according to monthly system conditions, and simulates generator forced outages by randomly drawing from distributions of time to fail and time to repair that are calculated from forced outage event statistics.
- Staff implemented 5% average outage rates for battery storage and pumped storage hydro, as well as a discharge limit on battery storage set at 90%, both intended to better reflect observed battery performance in the CAISO market. The model ignores the discharge cap under conditions where loss-of-load is imminent so this particular constraint should have minimal effect on LOLE analysis results. These assumptions are consistent with those used for the IRP's Preferred System Plan model in SERVM.
- Staff did not consider potentially significant departures from historical hydro and weather patterns in the future due to climate change. Staff's model data is based on historical data from 1998-2017 and does not consider lower hydro and hotter weather observed in recent years. Staff expects to develop methods to better account for climate change in subsequent studies.

Modeling Path 26 - Relaxation of Intra CAISO Constraints

The CAISO in total is divided into four regions, each modeled independently but linked as a co-region. Each region in CAISO (PGE_Bay, PGE_Valley, SCE and SDGE) broadly represents the Transmission Access Control (TAC) areas within CAISO and are linked by the transmission network that makes up CAISO. A key transmission limit is the Path 26 constraint limiting the flow of energy from north to south and vice versa, generally along the boundary of PG&E's TAC to the north and SCE's TAC to the south. 4,000 MW of power can flow south from PG&E's system to SCE's system, while 3,000 MW can flow north. Staff wanted to ensure that constraints caused by Path 26 did not distort LOLE and ELCC analysis. Staff conducted sensitivity analysis by increasing capacity on Path 26 and observing the effect on LOLE and counting the number of hours where the Path 26 constraint was binding. As the Path 26 constraint was relaxed, LOLE decreased modestly. This indicates that location of resources between north and south to minimize Path 26 congestion may modestly influence the total amount of resources and RA obligations needed to achieve a desired level of LOLE.

Ultimately for the LOLE and ELCC studies here issued, staff relaxed Path 26 constraint values, setting the south to north constraint at 7,000 MW and the north to south constraint at 8,000 MW. With the goal of minimizing the total amount of generation (and RA requirement) across the whole CAISO to achieve the LOLE target, staff also relaxed the path constraint across the SCE and SDGE interface, from 4,739 MW to 8,739 MW for SCE to SDGE and from 2,500 MW to 6,500 MW for SDGE to SCE.

Figure 3 shows a ranked distribution of binding hours for flow from PGE_Valley to SCE areas, with the blue line at the 4,000 MW of limit on Path 26. The x-axis represents the 100 cases run by Energy Division staff and the y-axis represents the number of binding hours for a case. A few cases had more than 50 binding hours in the year, while most cases were below that. As the capacity on Path 26 increased, most cases fell below 10 binding hours. This suggests that the effect on LOLE may be modest in a few cases.

Figure 3: Binding hours North to South as Path 26 capacity increases

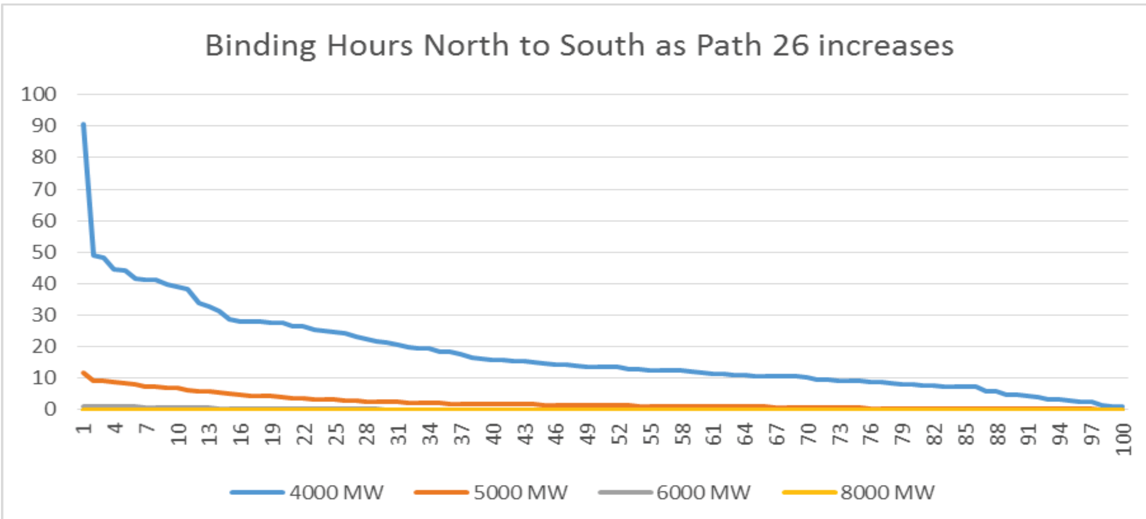


Figure 4 shows a larger number of binding hours for flow from SCE to PGE_Valley, with a similar distribution shape. The number of binding hours is larger south to north although this likely demonstrates increased flow of renewables from SCE area in the future rather than a binding constraint that would affect reliability. Likewise, as capacity limits are relaxed, binding hours decrease.

Figure 4: Binding hours South to North as Path 26 capacity increases

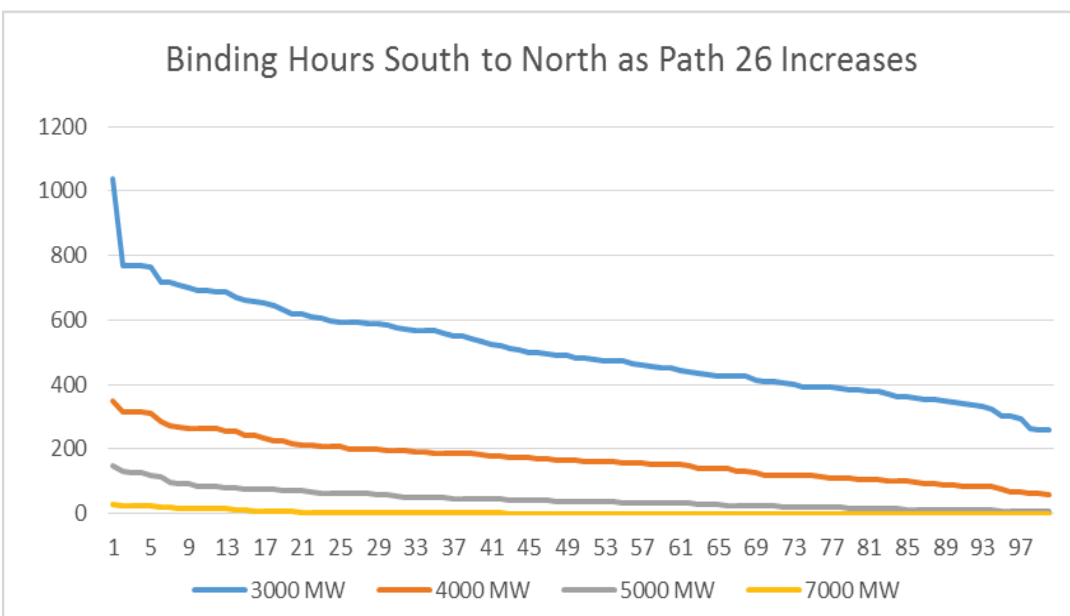


Table 2 shows the decrease in LOLE as Path 26 capacity increases.

Table 2: LOLE at different increments of relaxing the S-N Path 26 constraint

Path 26 constraint S-N	3,000 MW	4,000 MW	5,000 MW	7,000 MW
LOLE	0.107	0.102	0.089	0.075

5. LOLE and ELCC Methodology

The first step is establishing a model of the electric system calibrated to a 0.1 LOLE reliability level. Subsequent ELCC analysis relies on the calibrated system as a reference point. Since the RA program is a monthly program, staff needs to calibrate the electric system for each month such that LOLE events are surfaced even in off-peak months in order to calculate RA requirements in those months. Staff performed these steps, all with respect to the CAISO Balancing Area:

1. Staff iteratively removed or added varying amounts of generation in each month such that off-peak months were calibrated to have a very small but non-zero LOLE and the summer months were allowed to have higher LOLE, so long as total LOLE for the entire year was about 0.1. Staff removed (or added back) the oldest generation first (typically Coal, CT, CCGT, Cogen, ICE, and Nuclear).
2. The final monthly amounts of capacity remaining in the electric system calibrated to 0.1 LOLE were tabulated to be used later in the PRM calculation.

Next, monthly ELCC analysis was performed to determine the effective capacity of the variable and energy-limited resource portfolio. For these steps, staff retained the services of Astrapé Consulting to perform the ELCC analysis. Astrapé determined the average portfolio ELCC by month and then employed a modified version of the "Delta Method" (a new method relative to previous ELCC analyses adopted in the RA proceeding) to allocate ELCC to the different resource technologies within the portfolio. The modified Delta Method includes a proportional adjustment for diversity among resource technologies and ensures the sum of resource technology-specific effective capacity equals the portfolio effective capacity.

3. The average ELCC of the variable and energy-limited portfolio was determined as follows:
    a. Removed the variable and energy-limited portfolio from the four CAISO zones in the model: PGE_Bay, PGE_Valley, SCE, and SDGE. The removed portfolio included these unit categories, which were further consolidated into four technology groups for later determination of technology-specific ELCCs:

Table 3: Technology Groups and Unit Categories of variable and energy-limited portfolio

Portfolio Technology Group	SERVM Unit Category Name	Description
Solar	Solar_Fixed	Utility-scale fixed-tilt solar PV
	Solar_1Axis	Utility-scale single-axis tracking solar PV
	Solar_2Axis	Utility-scale dual-axis tracking solar PV

	Solar_Thermal	Solar thermal
Hybrid	Hybrid	Single-axis tracking solar PV portion (of pairing with battery storage)
	Hybrid Storage	Battery storage portion (of pairing with single-axis tracking solar PV)
Storage	Battery Storage	Battery storage
	PSH	Pumped storage hydro
Wind	Wind	Wind, in-state only

b. Retained the following categories of variable and energy-limited resources in the monthly calibrated system:
    - BTMPV (Behind-the-meter solar PV, demand reduction already counted in RA compliance accounting)
    - BTM Battery Storage (Behind-the-meter battery storage, net effect on demand already counted in RA compliance accounting)
    - Remote generators (Out-of-state wind and solar, all of which is assumed to lack dedicated transmission into CAISO and is therefore assumed as part of the 4,000 MW import constraint and not affecting the ELCC of generation located within the CAISO area)

c. Iteratively added back "perfect capacity" in each month until monthly LOLE returns to the monthly calibrated target level.
    - "Perfect capacity" is an idealized combustion turbine (CT) with zero cost, infinite ramping, zero startup, no emissions, no generator outage rates, etc.
    - Added back perfect capacity according to the following percentages:
        - 50% – SCE
        - 50% – PGE_Valley
    - Constraints between SCE-SDGE and SCE-PGE_Valley were relaxed for the ELCC analysis to ensure congestion associated with the addition of perfect capacity in the above proportions did not unduly influence the ELCC calculation.

d. Calculated the monthly effective capacity and ELCC of the variable and energy-limited portfolio as follows for each month:

    Portfolio effective capacity = MW of perfect capacity that was added back to return to that month's calibrated LOLE target level

    Portfolio ELCC (%) = (Portfolio effective capacity MW) / (Variable and energy-limited portfolio MW)

4. The average ELCCs for the different technologies within the variable and energy-limited portfolio were determined as follows:
    a. Calculated monthly "First-In" marginal ELCCs for each technology (i.e., when the penetration level of a particular technology is 0% of the full portfolio):

- Removed all technology portfolios from calibrated system and recalibrated to monthly LOLE targets by adding Perfect Capacity
- For each technology (e.g., wind), added a 1,000 MW block of marginal generation to the recalibrated system
- Iteratively added "perfect load" (via negative perfect capacity) in each month until monthly LOLE returned to target levels
- For each month:

  "First-in" marginal ELCC = (Perfect load MW added) / (Marginal generation MW of the technology added)

- Repeated for each technology

b. Calculated monthly "Last-In" marginal ELCCs for each technology (i.e., when the penetration level of a particular technology is 100% of the full portfolio):
   - Kept full portfolio of all technologies in calibrated system
   - For each technology, added a 1,000 MW block of marginal generation to the calibrated system with the full portfolio of all technologies already present
   - Iteratively added "perfect load" (via negative perfect capacity) in each month until monthly LOLE returned to target levels
   - For each month:

     "Last-in" marginal ELCC = (Perfect load MW added) / (Marginal generation MW of the technology added)

   - Repeated for each technology

c. For each technology and for each month, calculated an initial average technology ELCC as the average of the First-In ELCC value and the Last-In ELCC Value

d. Calculated the monthly Weighted Average ELCC of the technology ELCC values as the sum product of the technology size (in MW) and the technology ELCC divided by the total portfolio size

   Weighted Average ELCC = sum product (technology MW * technology ELCC) / Portfolio MW

e. Calculated a monthly diversity adjustment factor as the ratio of the original Portfolio ELCC divided by the Weighted Average ELCC of the technologies

   Adjustment Factor = Portfolio ELCC / Weighted Average ELCC

f. Calculated the final monthly technology ELCC values by multiplying the initial technology ELCC values by the adjustment factor. This results in the weighted average of the final monthly technology ELCC values equaling the monthly Portfolio ELCC value.

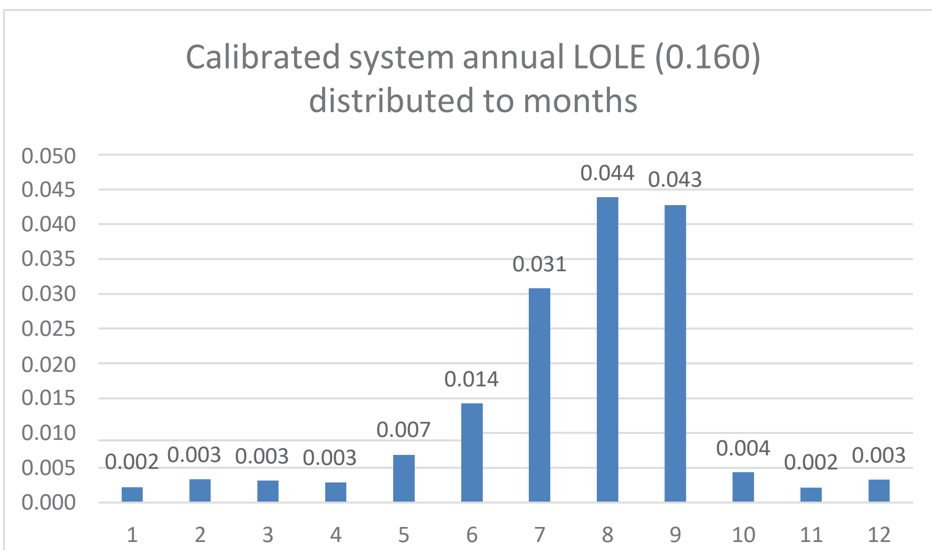
6. Results

Calibrated System with Base Portfolio

The 2024 RA study year model was ultimately calibrated to result in a probability-weighted average LOLE of 0.16 total across all 12 months of the year, with 0.13 LOLE concentrated in the peak months of June through September. Staff assumes that achieving 0.13 LOLE for the peak months is sufficiently close to achieving a 0.1 LOLE reliability level annually, given that in actuality a system would generally have excess supply (or contingency resources) and no loss-of-load events in off-peak months. Bear in mind that for calibration, existing units that would otherwise operate are removed in the study for the purpose of finding the point at which loss-of-load events begin to surface. For this reason, certain firm resources (specifically one unit of Diablo Canyon and all existing cogeneration resources) were removed, although we expect them to operate through 2024. In their place, staff added a large portfolio of resources representing projects under development as reported in LSE IRP Plans (filed September 2020) including any portion that can count towards the IRP Mid Term Reliability (MTR) Procurement Decision (D.21-06-035). Finally, some additional capacity came from the RESOLVE model to fill out the remaining MTR procurement need not already counted with LSE Plans and development resources. This PSP portfolio does not include firm long-lead time resources (e.g., long duration storage, geothermal) meant to replace Diablo Canyon that the CPUC has ordered to come online in later years.

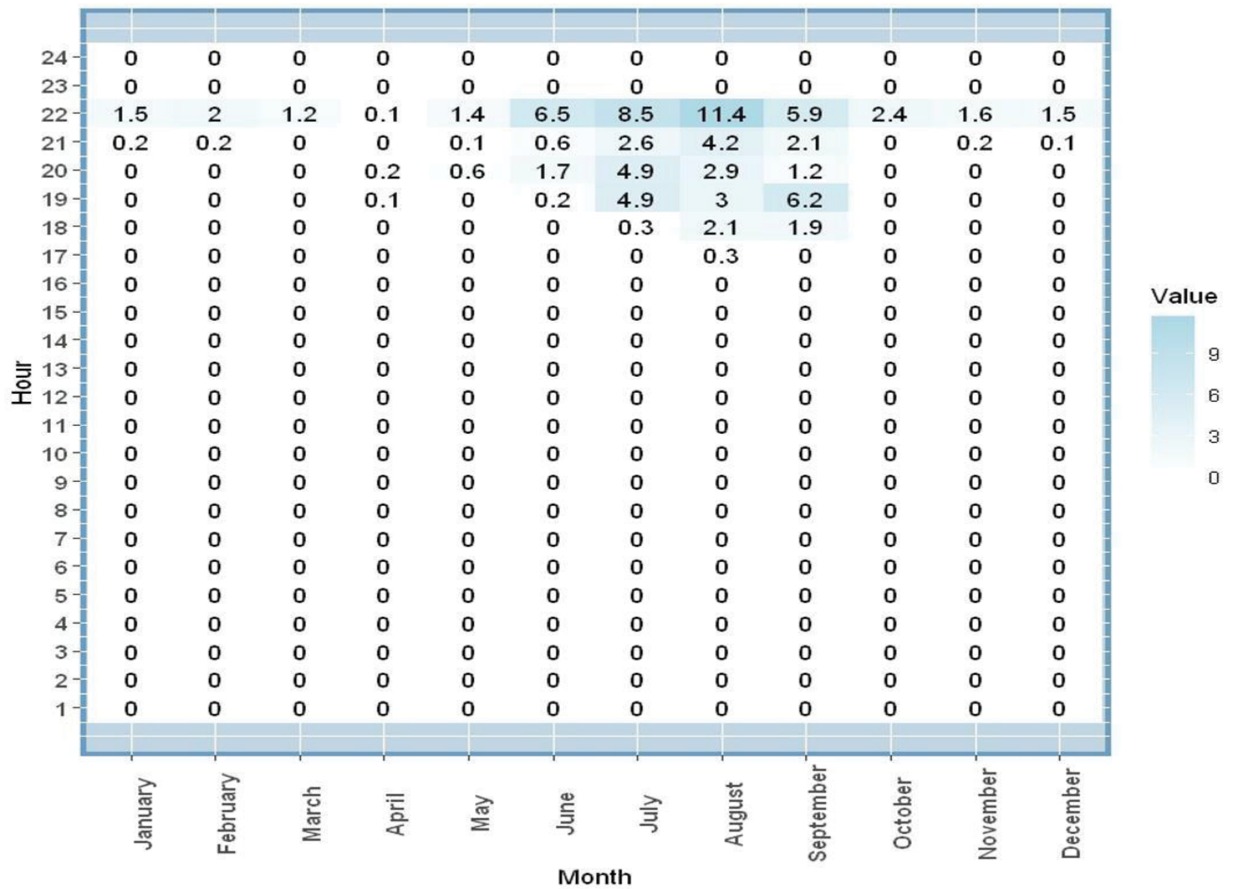
Figure 5 shows the distribution of LOLE across months of 2024. Calibration is a laborious process, iteratively adding or removing units and recalculating LOLE until achieving the desired target. Further modeling to fine tune monthly LOLE would be time consuming and would yield diminishing returns.

Figure 5: Distribution of LOLE across months in calibrated LOLE 2024 system



The heatmap shown in Figure 6 demonstrates the extent to which EUE has moved to later in the evening, now concentrated in the late evening and night of summer months, with much smaller amounts in other late night hours in off-peak months. The shift to late hours broadly represents the saturation effects of large amounts of solar and storage added to the fleet. EUE events that in the past would have been in the middle of the day at peak consumption and even events in the early evening demand are now effectively met with solar and storage. This implies that during these EUE hours solar has ramped down and storage has significantly discharged at HE20 to HE23.

Figure 6: Calibrated LOLE 2024 system Expected Unserved Energy (MWh)



Off-peak months required less capacity to protect against LOLE events, given significantly lower electric demand relative to summer peak demand. To account for this, staff removed additional existing capacity in off-peak months in order to surface loss-of-load events in all months of the year. This enabled a more accurate assessment of the necessary PRM in each month individually and verification of the RA program's design that each month targets about the same PRM for setting RA requirements. Table 4 reflects CAISO area installed capacity that was added or removed from the system to achieve calibration. Table 4 also reflects that limited capacity was removed in peak months in order to surface reliability events, namely one unit at Diablo Canyon Power Plant, the cogeneration fleet, the remote Intermountain Power Plant, and a handful of older CTs (highlighted in yellow).

Table 4: CAISO area installed capacity removed (negative values) to calibrate electric system

Before calibration installed capacity MW		Units removed for calibration by month in installed capacity MW											
Unit Category	CAISO	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CC	16,135	-4,737	-5,404	-6,836	-9,318	-9,367	-2,986	0	0	-603	-4,029	-5,404	-4,591

Cogen	2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298	-2,298
CT	8,370	-2,924	-3,039	-3,607	-4,274	-3,413	-2,629	-311	0	-1,295	-2,724	-3,170	-3,050
ICE	255	0	0	0	0	0	-44	0	0	0	-44	0	0
Nuclear	2,935	-1,785	-1,785	-1,785	-1,785	-1,785	-1,785	-1,150	-1,150	-1,150	-1,150	-1,785	-1,785

Table 5 shows the ELCC study Base Portfolio of variable and energy-limited (solar, wind, storage, and hybrid) resources that was analyzed and distinguishes between existing capacity and capacity under development. “Hybrid Combined” represents the total interconnection capacity of each hybrid unit and is smaller than the sum of capacity from the “Hybrid Solar Portion” and the “Hybrid Storage Portion” because not all projects interconnect the full capacity of both the solar and storage portions. Furthermore, only a portion of the Hybrid Storage is restricted to charge from its co-located solar, based on what LSEs reported for hybrid projects in their IRP filings from September 2020.

Staff uses the label “hybrid” in this report to match with labels used in SERVM. Under IRP naming conventions, “hybrid” is termed “paired,” meaning resources that are co-located and share an interconnection, but not necessarily with a charging restriction, while the term “hybrid” is reserved for resources that are co-located, share an interconnection, and do have a charging restriction. In contrast, Table 5 amounts for hybrids equate to “paired” in IRP terminology, representing all co-located resources sharing an interconnection and only a portion of those hybrids have a charging restriction in place.

Table 5 column “LSE Plans and development resources” represents projects under development as reported in LSE IRP Plans (filed September 2020) including any portion that can count towards the IRP Mid Term Reliability (MTR) Procurement Decision (D.21-06-035). The column “Additional capacity selected in RESOLVE” represents what the RESOLVE model selected to fill out the remaining MTR procurement need not already counted with “LSE Plans and development resources.”

Table 5 explicitly shows the Base Portfolio and the large portfolio of new construction, in particular nearly 9,000 MW installed capacity of new storage (including from hybrid projects), to meet reliability targets in 2024. This large portfolio is to test the effects of the investment on average ELCC values as a bookend given a portfolio like this will probably be realized as we approach 2030.

Table 5: Comparison of Base Portfolio existing online installed capacity MW vs. projected online in 2024

Portfolio Technology Group	Unit Category	Existing Online	LSE Plans and development resources	Additional capacity selected in RESOLVE	Portfolio Totals
Solar	Solar	12,066	3,762	0	15,829
Wind	Wind	6,971	1,307	0	8,279
Storage	Battery Storage	2,093	3,916	4,077	10,086
	PSH	2,099	0	0	2,099
Hybrid	Hybrid Combined	4,676	2,806	0	7,482
	Hybrid Solar Portion	3,158	2,135	0	5,292
	Hybrid Storage Portion	1,619	953	0	2,571

The resources modeled in the Base Portfolio calibrated fleet were reconciled with the 2022 NQC List[12] on a unit by unit basis in order to tabulate their effective capacity using current NQC counting rules for all resources not currently online. For resources within the ELCC study Base Portfolio (wind, solar, battery storage, pumped storage hydro, and hybrids), their effective capacity was determined by the monthly portfolio ELCC values calculated in the study. Table 6 summarizes the total effective capacity in the calibrated system by unit category. For comparison, Table 7 shows just the ELCC study Base Portfolio (of solar, wind, storage, and hybrids) but with NQC quantified using currently effective ELCC values. The comparison illustrates the significant reduction in ELCC values due primarily to the fact that we are modeling a portfolio with significantly greater penetration of solar, wind, and storage resources than exists today.

Table 6: 2024 calibrated fleet effective capacity in MW using current NQC counting except Base Portfolio of solar, wind, storage, & hybrid use new portfolio ELCC

Unit Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Biogas	212	211	212	205	200	206	205	207	208	205	209	208
Biomass/Wood	448	448	430	415	434	451	456	457	456	430	419	438
CC	11,331	10,683	9,245	6,766	6,684	13,001	15,966	15,961	15,384	12,014	10,673	11,489
Cogen	0	0	0	0	0	0	0	0	0	0	0	0
CT	5,385	5,265	4,701	4,074	4,873	5,634	7,854	8,162	6,925	5,566	5,138	5,258
DR	729	776	744	854	916	1,060	1,072	1,106	1,114	951	844	725
Geothermal	1,249	1,249	1,245	1,235	1,236	1,233	1,237	1,237	1,238	1,241	1,248	1,249
Hydro	4,429	4,294	4,313	4,741	5,023	5,499	5,849	5,620	5,002	4,155	4,084	4,272
ICE	255	255	255	255	255	211	255	255	255	211	255	255
Nuclear	1,140	1,140	1,140	1,140	1,140	1,140	1,775	1,775	1,775	1,775	1,140	1,140
Solar, Wind, Storage, & Hybrid Portfolio	10,396	12,152	11,834	12,597	14,539	16,431	17,926	16,582	15,742	12,613	12,048	10,385
Interchange	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Total	39,573	40,471	38,118	36,281	39,299	48,865	56,593	55,362	52,098	43,161	40,058	39,419

Table 7: Base Portfolio effective capacity if NQC quantified using current technology factors

Unit Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar, Wind, Storage, & Hybrid Portfolio	15,881	15,552	19,639	18,914	19,111	22,603	23,281	20,824	17,865	15,042	15,363	15,069

UCAP and Scheduled Maintenance

During the course of a year, a significant portion of RA capacity may be on planned or forced outage. Planned outages for scheduled maintenance, under current CAISO planned outage substitution rules,

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

results in generator owners providing substitute capacity (when needed) to replace their committed RA capacity. Generator owners schedule maintenance during off-peak months when demand is low and it is often unlikely that their generator or substitute capacity is needed.

Forced outages on the other hand are random and can be characterized by NERC GADS statistical metrics such as Equivalent Forced Outage Rate (EFOR and EFORd). EFOR is the capacity weighted average forced outage rate of a generator category, and EFORd is the same calculation but only in periods of demand when the generator is online. EFORd is smaller because it excludes reserve shutdown hours from the calculation. The NQC of a generator can be derated by either its EFOR or EFORd to account for forced outages. This is called the generator's Unforced Capacity or UCAP. The annual average EFOR and EFORd values in this report's LOLE and ELCC studies by unit category are shown Table 8.

These outage rates are based on class averages by technology type derived from GADS data and are included in the model. Other types of resources (wind, solar, biomass) do not have outage rates entered into SERVM. Steam and coal technology types are not present in the 2024 calibrated system. EFOR and EFORd information is entered into the model as a distribution of time to repair and time to fail values. Outage rates in results partially depend on the amount of usage in the model over the course of the year.

Table 8: EFOR and EFORd used in SERVM

CAISO Unit Category	EFOR (%)	EFORd (%)	Startup probability (%)
Battery Storage	5.4	0.0	97.9
Combined Cycle	9.1	7.7	98.6
Combustion Turbine	22.1	11.2	99.5

Staff chose to use EFORd to calculate UCAP NQC since it is more consistent with a proposal from the CAISO to calculate UCAP NQC from forced outage rates. CCs and CTs are the only unit categories for which a UCAP NQC are calculated. Categories of units which receive NQC based on ELCC or historical production data have forced outages included already. Table 9 summarizes the total effective capacity in the calibrated system by unit category using UCAP NQC for CCs and CTs (highlighted in yellow).

Table 9: 2024 calibrated fleet effective capacity in MW using current NQC counting except UCAP for CC and CT, and Base Portfolio of solar, wind, storage, and hybrid use new portfolio ELCC

Unit Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Biogas	212	211	212	205	200	206	205	207	208	205	209	208
Biomass/Wood	448	448	430	415	434	451	456	457	456	430	419	438
CC (UCAP)	10,424	9,905	8,617	6,359	6,323	12,322	15,054	15,014	14,480	11,228	9,828	10,589
Cogen	0	0	0	0	0	0	0	0	0	0	0	0
CT (UCAP)	4,782	4,691	4,191	3,592	4,365	5,238	7,222	7,530	6,377	5,072	4,549	4,694

DR	729	776	744	854	916	1,060	1,072	1,106	1,114	951	844	725
Geothermal	1,249	1,249	1,245	1,235	1,236	1,233	1,237	1,237	1,238	1,241	1,248	1,249
Hydro	4,429	4,294	4,313	4,741	5,023	5,499	5,849	5,620	5,002	4,155	4,084	4,272
ICE	255	255	255	255	255	211	255	255	255	211	255	255
Nuclear	1,140	1,140	1,140	1,140	1,140	1,140	1,775	1,775	1,775	1,775	1,140	1,140
Solar, Wind, Storage, & Hybrid Portfolio	10,396	12,152	11,834	12,597	14,539	16,431	17,926	16,582	15,742	12,613	12,048	10,385
Interchange	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Total	38,063	39,119	36,981	35,391	38,431	47,791	55,050	53,784	50,646	41,881	38,625	37,956

PRM Calculation

Staff present PRM values using the new ELCCs under both UCAP and current NQC counting for CCs and CTs as shown in Table 10 and Figure 7. Planned maintenance (modeled to be as high as 1.7% of peak load in March) generally occurs in the winter and spring when CAISO area supply conditions are not tight. Planned outages can potentially be removed from the monthly PRM calculation if this amount of capacity was not contributing to LOLE reduction in the model in that month. It is possible however, that planned outages could be concentrated in parts of the month not coincident with the monthly peak. In this case, the capacity that was on planned outage was actually available and contributing to LOLE reduction, implying that planned outages should not be removed from the monthly PRM calculation. To reflect both of these potential circumstances, staff removed monthly planned outages from the PRM determination using the minimum daily MW on maintenance from the monthly distributions of capacity on planned outage in the model. This was meant to be conservative, and to reflect the possibility of maintenance occurring only in part of a month.

Table 10 shows that using UCAP NQC to account for forced outages reduces monthly PRMs by between 2.5% and 4.5%. Importantly, this derate does not reflect ambient derates, which differentiates staff's analysis from the CAISO's UCAP proposal. The peak demand values used to calculate monthly PRMs are derived directly from SERVM demand forecast inputs. It is the monthly median peak demand for the 20 weather years in SERVM, calculated as hourly consumption shapes net of hourly demand modifier shapes for AAEE, BTMPV, EV, and TOU, and net of the estimated peak impact of BTM battery storage.[13] SERVM monthly median peaks are not identical to the monthly managed peaks provided in the CEC's 2020 IEPR demand forecast. Even though SERVM demand forecast inputs are determined by the 2020 IEPR annual peak and energy forecast, staff developed its own 20 weather year set of hourly demand profiles which have a different monthly distribution than what the CEC uses to allocate its annual peak and energy forecast to months. To remain internally consistent, staff used the median monthly peaks from SERVM to determine PRMs since that monthly peak distribution was what determined the effective capacity requirement modeled in SERVM.

Another implication of calculating monthly PRMs to conform to the monthly RA construct is that median monthly peaks may differ from the median annual peak that would be used to calculate an

[13] Estimated by multiplying BTM battery storage installed capacity by its "combined availability" as modeled in SERVM.

annual PRM. This distinction is important as it relates to variability in peak months of a year. In some years, demand peaks in August, some years in July and some in September. This is due to weather variability that has heat waves or cold snaps occurring across the summer, not always in the same month. The median annual peak may turn out higher than the peak drawn from median monthly peaks. For that reason, comparison of an annual PRM calculated from the median annual peak may appear lower than monthly PRMs calculated from median monthly peaks. This effect could be as much as 2,000 MW in the CAISO system. To conform to the annual constructs used in both the IRP and the IEPR processes, staff "annualized" the median monthly peaks in SERVM by scaling the median monthly peaks by the ratio of the median annual peak to the highest median monthly peak. This ensures the median annual peak matches the highest median monthly peak, conforms to the deterministic average forecast provided in the IEPR demand forecast, and makes the monthly PRMs used for RA comparable to annual PRMs that are used in the IRP process.

Table 10: Comparison of monthly PRM under current NQC counting, with the new solar, wind, storage, and hybrid portfolio ELCC, and with UCAP for CCs and CTs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Effective Capacity: NQC current, new Portfolio ELCC	39,573	40,471	38,118	36,281	39,299	48,865	56,593	55,362	52,098	43,161	40,058	39,419
Effective Capacity: NQC current, UCAP, new Portfolio ELCC	38,063	39,119	36,981	35,391	38,431	47,791	55,050	53,784	50,646	41,881	38,625	37,956
Planned Outages Removal	0	154	564	416	15	137	0	0	0	0	0	0
Planned Outages Removal, UCAP	0	143	527	390	14	130	0	0	0	0	0	0
SERVM Sales Peak	33,364	31,957	31,341	32,502	35,180	44,089	47,253	46,380	43,152	36,452	33,359	34,018
PRM, NQC current, new portfolio ELCC	19%	26%	20%	10%	12%	11%	20%	19%	21%	18%	20%	16%
PRM, NQC current, UCAP, new portfolio ELCC	14%	22%	16%	8%	9%	8%	16%	16%	17%	15%	16%	12%

Figure 7: Comparison of monthly PRM under current NQC counting, with the new solar, wind, storage, and hybrid portfolio ELCC, and with UCAP for CCs and CTs

Deliverability Restrictions on NQC calculations

Staff performed the LOLE study without restricting the generation of individual generators, regardless of their deliverability restrictions (whether they are Energy Only, Full Capacity, Interim Deliverability, or Partially Deliverable). It was not practical in a LOLE study to attempt to simulate these restrictions, but staff also began to question the applicability of the deliverability restrictions across the full range of conditions that make up the LOLE study. For instance, different weather conditions may change how a resource is deliverable. In some weather conditions, the resource could well be deliverable when in other weather conditions, it may not be.

Deliverability studies are not able to be stochastic given the extreme granularity of the transmission model. That means the stochastic weather and generator outage scenarios tested in a LOLE model will likely result in deliverable energy from most generators regardless of the one case tested in the deliverability study. For that reason, it is unreasonable to simulate resources limited to deliverability amounts across all weather and generation scenarios, and in most instances, the conditions that result in impaired deliverability will not occur in real operations and under most weather events. The CAISO has begun to evaluate different deliverability methodologies to apply to variable generators driven by the fact that the majority of LOLE reliability events now occur after peak electric usage times, but that is only a partial fix. Significant MWs of NQC are restricted in RA compliance by limiting their NQC at deliverability, and staff believe it is likely more accurate to count this impaired generation towards RA obligations. This may result in less incentive to invest in transmission needed to ensure full deliverability of certain new resources, and this incentive effect is important to trade off against any general reliability benefits created by new transmission aside from the NQC deliverability limits.

Table 11 summarizes the MW NQC that is currently impinged due to the deliverability restrictions. These monthly MW values represent generation that, if deliverable, would be able to count towards RA obligations. Staff modeled this generation as in service in the LOLE study, and in reality this generation is often deliverable to aggregate CAISO load and does often provide reliability value.

Table 11: Undeliverable MW NQC on the 2022 NQC list

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MW	70	64	218	195	210	382	468	332	185	55	53	35

7. Base Portfolio and Resource Specific ELCC Results

Table 12 below lists Perfect Capacity amounts added to measure the equivalent ELCC value of each technology type in the Base Portfolio. Each month is assessed individually, with Perfect Capacity added each month to restore the monthly LOLE result to its calibrated value (e.g. 0.002 LOLE for January). The Total Portfolio is the combined solar, wind, storage, and hybrid portfolio. Perfect Capacity MW added divided by the portfolio size in installed capacity MW yields the ELCC percentage. The Perfect Capacity MW added is equivalent to the NQC value of the portfolio, also called effective capacity.

Table 12: Perfect Capacity equivalent in MW for Base Portfolio

Installed Capacity Total	12,185	15,828	7,482	8,279	43,774
	Individual Technology Effective Capacity				Portfolio Effective Capacity
	Storage	Solar	Hybrid	Wind	
January	7,351	58	1,153	1,834	10,396
February	8,005	488	1,657	2,002	12,152
March	7,629	586	1,850	1,768	11,834
April	7,766	865	2,208	1,759	12,597
May	8,887	1,249	2,730	1,672	14,539
June	8,995	2,561	3,302	1,572	16,431
July	9,768	2,781	3,862	1,515	17,926
August	9,797	2,421	3,111	1,254	16,582
September	9,828	2,197	2,442	1,274	15,742
October	8,465	1,521	1,519	1,108	12,613
November	8,099	1,194	1,362	1,392	12,048
December	6,950	611	1,090	1,734	10,385

Table 13 reflects individual technology specific ELCC values. These values vary by month, and are diversity adjusted to sum to the portfolio results. The storage values are to be applied to both batteries as well as pumped storage. For most resources, ELCC values are highest in the summer due to the predominance of solar and its interactions with storage, but wind has higher ELCC in offpeak months. The average ELCC values in this Base Portfolio are substantially lower than the previous ELCC study adopted in 2019 for 2020 RA year, reflective of significantly greater penetration of energy limited resources, specifically large amounts of new storage added pursuant to the IRP portfolio. This new storage added has changed the interactions between types of resources, while also decreasing the average value of storage itself due to the effects of declining reliability benefits.

For the first time, a specific ELCC value is calculated for storage and hybrid resources, and this modeling indicates that the significant growth in storage is leading to a penetration effect resulting in a decline in average storage ELCC. Relative size of resource portfolios is important, as the amount of solar affects how much storage can charge, and the amount of both solar and storage affects how much the peak is moved later in the evening, which would lead to higher value for wind which performs better during this period.

Table 13: Technology Specific ELCC values (%) for Base Portfolio

	Storage	Solar	Hybrid	Wind	Portfolio ELCC (%)
January	60.3%	0.4%	15.4%	22.2%	23.7%
February	65.7%	3.1%	22.2%	24.2%	27.8%
March	62.6%	3.7%	24.7%	21.4%	27.0%
April	63.7%	5.5%	29.5%	21.2%	28.8%
May	72.9%	7.9%	36.5%	20.2%	33.2%
June	73.8%	16.2%	44.1%	19.0%	37.5%
July	80.2%	17.6%	51.6%	18.3%	41.0%
August	80.4%	15.3%	41.6%	15.1%	37.9%
September	80.7%	13.9%	32.6%	15.4%	36.0%
October	69.5%	9.6%	20.3%	13.4%	28.8%
November	66.5%	7.5%	18.2%	16.8%	27.5%
December	57.0%	3.9%	14.6%	20.9%	23.7%

8. Alternative Portfolios and Impact on ELCC Results

Given the relationships between different technologies in terms of ELCC studies, staff explored different combinations of energy limited resources and penetrations in order to see what the average ELCC values would be under different horizons of resource development. In order to apply these values to 2023 and 2024 study years, a range of resource portfolios were analyzed to determine average ELCC values for each technology type (i.e. wind, solar, storage and hybrid).

The Base Portfolio assumptions reflect the IRP PSP for the 2024 time period which includes a large amount of new preferred resources that are projected to come online in 2024 based on filed IRP plans and RESOLVE capacity expansion modeling. Table 14 depicts the amount of in-development and other planned resources used to develop the alternative scenarios. We constructed four alternative scenarios shown in Table 15 to reflect the changes in ELCC values driven by different overall portfolio sizes and relative composition of the portfolios. The technology specific ELCC values are different in each scenario, but the PRM should not be affected because what was removed in these scenarios relative to the Base Portfolio would be replaced by equivalent effective capacity.

Table 14: Installed capacity assumptions for existing and new resources in the solar, wind, storage, and hybrid portfolio for 2023 and 2024

	Assumption #	1	2	3	4	5
Portfolio Technology Group	Unit Category	Existing	50% of LSE IRP Plans in-development resources	100% of LSE IRP Plans in-development resources	Additional Capacity selected in RESOLVE	Potential 2023 Portfolio
Solar	Solar	12,066	1,881	3,762	0	14,805
Wind	Wind	6,971	654	1,307	0	7,946
Storage	Battery Storage	2,093	1,958	3,916	4,077	4,161
	PSH	2,099	0	0	0	2,099
Hybrid	Hybrid Combined	4,676	1,403	2,806	0	6,687
	Hybrid Solar Portion	3,158	1,068	2,135	0	4,540
	Hybrid Storage Portion	1,619	477	953	0	2,108
	Total	27,905	5,896	11,791	4,077	35,698

Table 15: Scenarios using varying installed capacity assumptions for the size of the solar, wind, storage, and hybrid portfolio for 2023 and 2024

Scenarios	Assumption #'s	Portfolio MW
Base	**1+3+4**	43,773
Scenario A	**1**	27,905
Scenario B	**1+2**	33,801
Scenario C	**1+3**	39,696
Scenario D	**5**	35,698

Staff's consultant, Astrapé, was able to recalculate portfolio and technology ELCCs for different portfolio sizes based on first-in and last-in marginal ELCCs available from prior and related work.

Scenario A assumes that the portfolio is comprised of only the current resources on the system. Table 16 reflects what the ELCC values would be under this scenario. When compared against the Base Portfolio storage technology ELCC is higher due to less storage capacity in the portfolio which reflects that most value is provided by the first amounts installed. Solar average value continues to be lower than last modeled in 2019 due to significant growth, particularly in the underlying BTMPV penetration effecting supply side solar, and wind is a bit lower than it would be under the Base Portfolio as the peak is not moved to later in the evening when wind is more effective.

Table 16: Scenario A, existing resources only

Installed Capacity Total	4,192	12,066	4,676	6,971		27,905
	Storage	**Solar**	**Hybrid**	**Wind**	**Portfolio ELCC (%)**	**Portfolio ELCC (MW)**
January	71.7%	0.4%	14.8%	21.8%	18.9%	5,263
February	76.7%	3.0%	20.7%	23.2%	22.0%	6,152
March	72.8%	3.6%	23.1%	20.5%	21.5%	5,991
April	73.1%	5.2%	27.3%	20.2%	22.9%	6,377
May	75.9%	8.1%	37.0%	21.0%	26.4%	7,360
June	83.0%	14.5%	40.0%	17.4%	29.8%	8,318
July	92.0%	16.1%	47.8%	14.9%	32.5%	9,075
August	95.7%	14.5%	40.0%	11.0%	30.1%	8,394
September	97.5%	13.3%	31.8%	11.4%	28.6%	7,969
October	86.0%	9.3%	20.3%	10.2%	22.9%	6,385
November	78.5%	7.3%	17.4%	15.9%	21.9%	6,099
December	66.1%	3.7%	13.6%	20.1%	18.8%	5,257

Table 17 reflects the ELCC values under Scenario B which assumes the exsisting fleet of resources plus 50 percent of the MWs assumed in the 2024 PSP. The ELCC values reflect that by adding a larger amount of storage to the portfolio, it begins to lower the ELCC of storage, dropping it from 95.7% in August to 93.2% in August. This portfolio change also leads to a ~ 2% decline in the average solar ELCC and a ~ 2% increase in the average wind ELCC as net peak moves later in the evening.

Table 17: Scenario B, existing resources plus half of LSE IRP planned resources come online

Installed Capacity Total	6,150	13,947	6,079	7,625		33,801
	Storage	**Solar**	**Hybrid**	**Wind**	**Portfolio ELCC (%)**	**Portfolio ELCC (MW)**
January	69.1%	0.4%	14.0%	21.5%	20.1%	6,793
February	74.4%	2.9%	19.8%	23.0%	23.5%	7,940
March	70.7%	3.5%	22.1%	20.3%	22.9%	7,732
April	71.7%	4.8%	26.4%	20.2%	24.4%	8,231
May	76.9%	6.8%	36.2%	21.3%	28.1%	9,500
June	83.0%	13.5%	39.4%	17.8%	31.8%	10,736
July	91.3%	14.8%	46.7%	15.6%	34.7%	11,713
August	93.2%	12.9%	38.3%	12.8%	32.1%	10,835
September	94.6%	11.6%	30.4%	13.2%	30.4%	10,286

October	82.9%	7.8%	19.3%	11.7%	24.4%	8,241
November	77.5%	6.1%	16.9%	16.1%	23.3%	7,872
December	64.3%	3.7%	13.1%	20.0%	20.1%	6,786

Table 18 reflects the ELCC values under Scenario C which assumes the exsisting fleet of resources plus 100 percent of the MWs assumed in the PSP. Table 18 shows storage ELCC decreasing into the 80% range, solar declining further, and wind increasing further. The large difference between this portfolio and the Base portfolio is the additional 4,077 MW of storage and small amount of added solar added with the rest of the LSE IRP plans and RESOLVE capacity expansion on top of the existing baseline. This storage and solar decrease the average ELCC of storage and solar, since the large increase in storage moves peak later in the evening, which begins to help wind as wind is more effective later in the evening.

Table 18: Scenario C, existing resources plus all of LSE IRP planned resources come online

Installed Capacity Total	8,108	15,828	7,482	8,278		39,696
	Storage	**Solar**	**Hybrid**	**Wind**	**Portfolio ELCC (%)**	**Portfolio ELCC (MW)**
January	66.2%	0.4%	13.4%	21.4%	20.6%	8,195
February	71.4%	2.9%	19.0%	23.0%	24.1%	9,580
March	68.1%	3.3%	21.3%	20.4%	23.5%	9,329
April	69.8%	4.2%	25.7%	20.5%	25.0%	9,930
May	76.4%	5.9%	34.5%	21.1%	28.9%	11,461
June	80.8%	12.8%	38.4%	18.1%	32.6%	12,953
July	87.8%	13.9%	44.9%	17.4%	35.6%	14,131
August	89.3%	11.9%	36.7%	14.6%	32.9%	13,072
September	90.3%	10.6%	29.0%	15.0%	31.3%	12,410
October	78.8%	6.9%	18.3%	13.2%	25.0%	9,943
November	74.8%	5.4%	16.3%	16.5%	23.9%	9,498
December	62.4%	3.2%	12.7%	20.2%	20.6%	8,187

Finally, Table 19 reflects the ELCC values under Scenario D which assumes the IRP PSP for 2023 as opposed to 2024 (reflected in the Base Portfolio). This scenario was driven by the need to develop 2023 ELCC values for wind and solar as directed by D.21-06-029. This scenario provides ELCC values for storage, solar hybrid and wind some where in between Scenario A and B which may represent a more accurate picture of the what the portfolio would be like in 2023.

Table 19: Scenario D, 2023 Portfolio

Installed Capacity Total	6,260	14,805	6,687	7,946		35,698
	Storage 2023 Portfolio	**Solar 2023 Portfolio**	**Hybrid 2023 Portfolio**	**Wind 2023 Portfolio**	**Portfolio ELCC (%)**	**Portfolio ELCC**

					2023 Portfolio	(MW) 2023 Portfolio
January	70.5%	0.4%	13.8%	21.9%	20.0%	7,129
February	75.7%	3.0%	19.4%	23.4%	23.3%	8,333
March	71.8%	3.5%	21.6%	20.7%	22.7%	8,115
April	73.4%	4.4%	26.0%	20.7%	24.2%	8,638
May	78.6%	6.4%	35.5%	21.8%	27.9%	9,970
June	84.5%	13.1%	38.7%	18.2%	31.6%	11,267
July	92.6%	14.4%	45.6%	16.6%	34.4%	12,292
August	94.8%	12.4%	37.5%	13.8%	31.9%	11,371
September	96.3%	11.1%	29.8%	14.2%	30.2%	10,795
October	84.6%	7.4%	18.9%	12.6%	24.2%	8,649
November	79.6%	5.7%	16.7%	16.5%	23.1%	8,262
December	65.8%	3.5%	12.9%	20.5%	19.9%	7,121

9. Stability of LOLE and ELCC Values in Investment and Reliability Considerations

Current and future ELCC values affect procurement decisions for long lead time resources and for other investments like transmission assets. On the one hand, frequent changes in these values can complicate procurement decisions, but on the other hand, updated values are important to reflect reliability contributions of various types of resources. Ideally, it is preferable to perform LOLE and ELCC studies at the same time in order to capture the dynamic changes in the overall system consistently and ensure that the RA program provides a fleet of capacity to the market that will best protect reliability.

For purposes of investment signals, it is wise to keep the PRM stable for as long as possible. However, for purposes of accurately assessing reliability needs, more frequent updates to the PRM may be desirable. While changes to the overall portfolio should not raise or lower the PRM needed, other changes such as weather variability and magnitude of weather changes, as well as economic and demographic changes that affect underlying electric demand are harder to predict and very important to plan for. Other drivers include changes to reliability criteria (e.g. moving from a 4.5 percent to a 6 percent operating reserve requirement) and changes to import assumptions (capping import assumption at 4,000 MW).

Marginal ELCC studies provide planners with valuable metrics that may influence future investments in generating capacity. Marginal ELCC studies were recently published on the IRP webpage in October 2021 for purposes of measuring IRP compliance across each Mid-Term reliability procurement tranche. Unlike IRP, the RA program does not utilize marginal ELCC values but utilizes the average ELCC values which ideally should align with the marginal studies.

In some instances, periodic reanalysis of ELCC values may increase ELCC for some technology classes, and in some instances an increase in the penetration of technology portfolios may lead to a decline in the average ELCC value for a particular technology. Conversely, too much time passing between updates in LOLE and ELCC values may lead to significant distortions in how reliability is measured and capacity payments given to generators as they sign market contracts.

10. Questions to be Considered by Commission and Parties

Staff proposes that the Commission and parties consider the following questions in reviewing the results of the LOLE and ELCC studies.

1. Which portfolio scenario (Base, A, B, C or D) best represents the likely portfolio in 2024? Which set of technology ELCC values should be assumed in selecting the short term average ELCC values?
2. What, if any changes should be made to the assumptions used to perform the LOLE study?
3. Is a LOLE study appropriate to calculate RA obligations for: 1.) a peak RA capacity framework, 2.) a slice of day reliability construct?
4. How should planned outages be treated in calculating an RA PRM using an LOLE study?
5. Would removing deliverability restrictions in the NQC calculation be an accurate translation of the way that resources provide reliability value to CAISO in most instances, outside of particularly constrained times? Would it be possible that certain resources would avoid making transmission upgrades because they have less of an incentive? Do parties have any other arguments pro or con about deliverability restrictions in the QC calculation?
6. How often should staff perform LOLE studies for RA obligations and ELCC values? Are there problems with performing RA studies and ELCC studies together simultaneously as is done in this proposal?
7. Do parties have comments on the revised ELCC methodology which assign diversity benefits via a series of marginal ELCC studies at different portfolio penetration points? Or do parties prefer the older method of calculating a capacity weighted average method of assigning diversity benefit?
8. Should storage and hybrid resources be valued using an ELCC methodology?
9. Should the PRM be static across the year or vary monthly (or seasonally)? How should PRM and ELCC values be allocated across months? Via month specific studies or via some allocation method?
10. Should forced outage rates on thermal resources be included in setting their QC value? In other words, should the PRM be set using a UCAP or ICap framework? If an UCAP framework is used should the forced outage rates also include ambient derates?
11. Should the load forecast used to set RA requirements be based on the monthly load forecast produced by SERVM or the IEPR (as done today)? Should the PRM calculation (presented in Table 10) be based on the IEPR forecast as opposed to the SERVM monthly load forecast? Why or why not?