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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	Rulemaking 16-02-007

ADMINISTRATIVE LAW JUDGE'S RULING FINALIZING PRODUCTION COST MODELING APPROACH AND SCHEDULE FOR PREFERRED SYSTEM PLAN DEVELOPMENT

This ruling finalizes the production cost modeling approach that Commission staff will use to analyze electricity resource portfolios, leading to a recommendation for a preferred system plan (PSP) for the first cycle of the integrated resource planning (IRP) process, as described in Decision (D.) 18-02-018. This ruling also requires any other parties conducting modeling, to assess the same or alternative portfolios, to adhere to the approach described in this ruling, as well as to the requirements of Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure, when submitting any modeling results in comments on the record of this proceeding. The attachment to this ruling provides the detailed modeling specifications. This ruling also sets forth the timeline for the modeling and analysis, leading to a recommendation for a PSP, as well as opportunities for comments and input from parties.

1. Production Cost Modeling Approach to Support Development of Preferred System Plan

This section discusses the approach to be used for production cost modeling of scenarios to develop the PSP and test its reliability and feasibility. A proposed approach was included in an Administrative Law Judge (ALJ) ruling issued September 24, 2018. Comments and reply comments were received from parties, and several changes will be made to the approach in response, as discussed further in Sections 2 and 3 below.

1.1 Staff-Proposed Modeling Approach

The September 24, 2018 ALJ ruling contained an updated version of Attachment B from D.18-02-018, which detailed how production cost modeling will be used by the Commission in the IRP process. In addition, the ALJ ruling included a slide deck containing the production cost modeling and analysis the Commission staff conducted to study a version of the Reference System Plan adopted in D.18-02-018, calibrated to the California Energy Commission's Integrated Energy Policy Report (IEPR) demand forecast. The slide deck also compared staff modeling results with RESOLVE capacity expansion modeling similarly calibrated to the 2017 IEPR demand forecast.

1.2 Comments of Parties

Comments on the September 24, 2018 ALJ ruling were filed by the following parties: American Wind Energy Association California Caucus (AWEA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Independent System Operator (CAISO); California Wind Energy Association (CalWEA); Calpine Corporation; Center for Energy Efficiency and Renewable Technologies (CEERT); Green Power Institute (GPI); GridLiance West LLC; Large-Scale Solar Association (LSA); Natural Resources Defense Council (NRDC); California Public Advocates Office; Protect Our Communities Foundation (POC); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); The Utility Reform Network (TURN); Union of Concerned Scientists

(UCS); Vote Solar; Wellhead Power Solutions, LLC; and Women's Energy Matters (WEM).

Reply comments were filed by the following parties: CAISO; CEJA and Sierra Club, jointly; GPI; GridLiance; LSA and Solar Energy Industries Association, jointly; POC; and SCE.

Parties' comments and input generally fell into the following categories: 1) inputs and methods generally; 2) loss of load expectation (LOLE) and effective load carrying capability (ELCC) issues specifically; 3) outputs; and 4) process.

On inputs and methods, numerous parties argued that the inputs and methods of the RESOLVE and SERVM models were not sufficiently aligned for comparison. In particular, parties were concerned that SERVM outputs estimated that the greenhouse gas (GHG) emissions from the electric sector in 2030 would be higher than the 42 million metric tons (MMT) associated with the Reference System Plan (RSP) developed in RESOLVE and adopted by the Commission in D.18-02-018. Next, parties were concerned that SERVM results indicated much higher levels of curtailment than RESOLVE suggested. In addition, several parties felt that behind-the-meter photovoltaics (BTM PV) and utility-scale renewables needed further reconciliation between RESOLVE and SERVM. For example, the BTM PV energy generation in SERVM exceeded the CEC's 2017 IEPR forecast levels. Differences were also noted between the levels of out-of-state renewables assumed to be delivering to, and balanced in, the CAISO grid.

In addition, many parties continued to question the assumption, used also for the preparation of the Reference System Plan (RSP), that all thermal plants without specific retirement dates already announced, would remain online through 2030. Parties continued to suggest, at a minimum, use of a 40-year life expectancy, or, preferably, closer examination of issues related to economic retirement.

Several parties also sought more clarity and granularity on the SERVM modeling of air pollutants, especially with respect to the effects on disadvantaged communities.

Other corrections proposed by various parties included:

- Use of more granular import emissions factors to reflect cleaner Northwest imports, rather than assuming a fixed Northwest hydroelectric credit in emissions accounting.
- Updating operating reserves modeling to conform to the new National Electric Reliability Council (NERC)/Western Electricity Coordinating Council (WECC) BAL-002 standard.
- Lowering the net export limit from the CAISO system from 5000 megawatts (MW) to 2000 MW in 2030.
- Improving representation of storage dispatch in both models to account for differing storage use cases (such as providing contingency reserve rather than energy arbitrage, lowering customer bills in BTM installations, or pairing with solar).

Several parties also expressed concerns with the ELCC calculation framework and the associated LOLE reliability target. In particular, there were concerns that monthly studies increase the industry standard 0.1 LOLE on an annual basis to the equivalent of a 0.3 LOLE. Parties instead suggested moving to annual studies only, using the 0.1 LOLE target. In addition, some parties suggested addition or removal of capacity to calibrate to a particular LOLE target should be done proportionally by service area.

Several parties also highlighted the importance of a consistent ELCC framework across multiple proceedings at the Commission, including resource adequacy, IRP, renewables portfolio standard (RPS), etc., but parties differed in their recommended implementation. Some parties preferred average and some marginal ELCC values. Other parties preferred that ELCC methodological issues be litigated in one place, preferably the resource adequacy proceeding. Some parties also preferred that BTM PV have its own ELCC value and not be treated as a load-modifier, or at least not exclusively.

With respect to model outputs, several parties requested additional information from the production cost modeling process. In particular, parties would like to see reporting of air pollutant emissions for plants located in disadvantaged communities. In addition, some parties requested reporting of WECC-wide GHG emissions, to help better identify potential resource shuffling. Some parties also requested reporting of hourly average system emissions rates and marginal ELCC values by resource type to help inform future load-serving entity (LSE) plan development.

On the overall production cost modeling process, several parties pointed out a need for a more robust stakeholder engagement process to provide feedback to Commission staff, as well as to assist stakeholders in putting forth their own analysis for Commission consideration.

Most parties requested more detailed information on how the aggregated LSE plans will be compiled by Commission staff and how any contradictions will be resolved.

Finally, the CAISO, in particular, was concerned about timely delivery of reliability and policy-preferred base cases for the start of their 2019-2020 Transmission Planning Process (TPP) by no later than February 2019.

2. Modeling Approach for 2018 Preferred System Plan

Commission staff appreciates the constructive and detailed input on the production cost modeling approach provided by parties thus far and discussed further in the public workshop held on October 31, 2018. The requests of parties can be divided into two basic categories: 1) changes that can be accomplished in the near term in time for the development of the 2018 PSP and the portfolios for delivery to the CAISO TPP and 2) changes that will require more time, but can be developed for purposes of the next IRP cycle and development of the 2019 RSP. The first set of changes is discussed in this section and the second set is discussed in the next section of this ruling.

For inputs and methods to the 2018 PSP, Commission staff will make the following changes to their previous proposal:

- All fossil-fueled thermal generation units, including cogeneration, older than 40 years, will be retired, unless the unit has a contract that extends its life beyond that point.
- BTM PV energy production will be scaled down to more closely match RESOLVE's assumed levels and those in the 2017 IEPR forecast.
- Out-of-state renewables will be further differentiated to correctly represent whether they are delivering to and balancing within the CAISO, or not.
- Inclusion of battery storage resources that are part of the Commission's storage target procurement will be reconciled to ensure no double counting of new battery storage resources by the investor-owned utilities (IOUs).
- Certain out-of-state natural gas units (Arlington, Mesquite, Griffith, and Yuma) that were previously modeled as dynamically scheduled direct imports into the CAISO area will no longer be modeled as such. They will be modeled as units economically dispatched primarily into the regions where they are located. This is due to a revised understanding of how dynamically-scheduled resources are used in the CAISO market.

The changes to the above elements will likely have an impact on the GHG emissions estimated from SERVM. For purposes of this PSP, any remaining

GHG emissions differences emanating from differences in the models will remain, and will be further investigated for the 2019-2020 IRP cycle.

In addition, Commission staff will conduct annual LOLE studies using SERVM to determine if at least 0.1 LOLE reliability is achieved. This will be done for the 2030 study year only (*i.e.*, similar to the "as found" type of studies that were conducted on the RSP and included in the September 24, 2018 ALJ Ruling). Staff will not perform additional ELCC studies for development of the PSP, because the portfolios are not expected to differ significantly enough from the RSP portfolio already studied. Finally, staff will further analyze reliability by removing effective capacity until the 0.1 LOLE target is reached, providing an additional indicator of, though not an exact estimate for, the amount of effective capacity available that is in excess of that necessary to meet at least a 0.1 LOLE reliability level on an annual basis.

With respect to model outputs, Commission staff will produce WECC-wide GHG emissions levels. Post-processing work will also be done to report amounts of criteria pollutants emitted by classes of plants and not specific units, due to data confidentiality requirements and the need for aggregation to respect those requirements. In the next IRP cycle, more granular reporting of criteria pollutant emission impacts on disadvantaged communities will be quantified, to the extent feasible.

The above modeling changes will be made in order to analyze a portfolio of electric resources assembled by Commission staff, termed the "hybrid conforming" portfolio.

The "hybrid" portion of the name references modifications to be made to the LSEs' conforming portfolios. The aggregation of new resources proposed by LSEs will be compared against the RESOLVE model assumptions for technical resource potential in the competitive renewable energy zones (CREZs) in which the resources are located, as well as the assumed available full deliverability and energy-only interconnection capacities in the regions where the CREZs are located. If the assumed resource potential and available transmission capacities are exceeded, staff will manually modify the location and deliverability assumptions for the aggregation of new resources proposed by LSEs to ensure that capacity stays within the physical limits assumed by the RESOLVE model. Staff will use the use resources selected in the RSP calibrated to the 2017 IEPR as a guide for how to modify the location and deliverability assumptions in the aggregation of new resources proposed by LSEs.

The "conforming" portion is so named because it uses as a starting point the conforming portfolios in the individual IRP filings of all LSEs who filed a standard IRP, by the requirements of D.18-02-018. The conforming portfolios were the most straightforward to aggregate because together they represent a system that was planned to match with the sum of each LSE's assigned conforming load share, which by definition and by design, add up to the CAISO system load total as reflected in the 2017 IEPR forecast. While some LSEs also submitted preferred portfolios, in Commission staff's judgment they do not merit separate modeling: the preferred portfolios of several IOU LSEs reflected policy preferences for cost recovery or GHG emissions targets in 2030 that either have not materialized or may not, while those preferred portfolios of smaller LSEs did not, in aggregate, impact system-level resource investment decisions enough to justify separate modeling.

In addition, about half of the LSEs filing standard plans chose their conforming portfolio as their preferred portfolio. For several electric service providers (ESPs), the primary difference between their conforming and preferred portfolios was their preferred custom hourly load shape, which did not actually appear to have a significant impact on their planned resource portfolio. Finally, several IOUs and community choice aggregators (CCAs) planned, in their preferred portfolios, for a different load forecast than assigned, which makes the total load in the CAISO system irreconcilable for system modeling purposes.

As pointed out by several stakeholders at the October 31, 2018 technical workshop, the "hybrid" step of manually rearranging the aggregation of new resources proposed by LSEs has the potential to undermine the purpose of the transmission planning process conducted by the CAISO, if the Commission were to assume that the resource locations selected by the LSEs were intentional and highly likely to occur. However, in this first round of IRP filings, numerous LSEs included multiple caveats to their plans, suggesting that the locations and resource selections are indicative but not necessarily probable, particularly since many of the investments will occur far in the future and presumably after some type of competitive process to determine the most economic investment options.

Given the uncertainty associated with the exact resource selections from LSEs, many of whom are new entrants to the electricity market, it does not seem prudent to base transmission investment analysis and decisions in 2019-2020 on LSE plans that are speculative or indicative only. In future rounds of IRP, as assumptions and planning activities become more routine, and IRP filings more clearly distinguish firm planning choices from speculative ones, it is likely that Commission staff will not need to perform this manual step of reassigning resource location based on technical potential or transmission constraints. The Commission may also consider modifications to the IRP requirements in the future to ensure that LSEs' degree of certainty in specific resource selections is clearer in their filings and may also consider program refinements as needed to ensure that plans are actionable and accountable, and not merely speculative.

After completing the above steps, Commission staff has produced a complete set of data to be used in SERVM production cost modeling, including the list of generation resources for 2030, hourly electricity consumption shapes, intermittent generation profiles, hydro generation profiles, and fuel and carbon prices. These items, including the complete set of data Commission staff will use, with the exception of certain confidential data, are posted on the Commission's web site at the following link: http://www.cpuc.ca.gov/General.aspx?id=6442459406.

All of this information is being made available by Commission staff for other parties who wish to conduct their own modeling studies of the "hybrid conforming" portfolio, or their own preferred aggregated portfolios, in 2030.

Commission staff intends to conduct production cost modeling of the "hybrid conforming" portfolio. If results are acceptable, staff will most likely recommend this portfolio as both the reliability base case and the policy-driven base case for the CAISO's TPP analysis. A formal ruling, issuing for party comment the modeling results and staff recommendations on the CAISO TPP portfolios will follow, as detailed further below in Section 4 concerning schedule.

Parties who have the capability and desire to conduct production cost modeling in parallel with Commission staff analysis will also be invited to submit their own results and recommendations in response to the forthcoming ruling. There will also be an opportunity to present informally at a workshop in early January 2019.

Parties conducting modeling and intending to submit their results and recommendations in comments will be required to adhere to the specifications in

Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure. The requirements therein are particularly relevant for parties using models other than RESOLVE or SERVM, since there are requirements to present, in addition to assumptions and results, a detailed set of information about how the utilized model operates.[1]

Finally, parties conducting independent modeling are required to follow the guidelines outlined in the Attachment to this ruling, which is an update to the production cost modeling guide in IRP that was attached both to D.18-02-018 (Attachment B) and updated in the September 24, 2018 ALJ ruling (Attachment A).

3. Modeling Approach for 2019-2020 IRP Cycle

This section describes the modeling improvements that Commission staff intend to undertake for the next IRP cycle. The most important structural change is to develop the RSP in RESOLVE in conjunction with testing portfolio reliability with production cost modeling in SERVM. In the current IRP cycle, due mostly to time constraints, the RESOLVE portfolio for the RSP was adopted by the Commission prior to being tested in SERVM. Data development was also conducted in series, such that new information became available after adoption of the RSP and prior to SERVM review, leading to inconsistencies in the two analyses driven by differing assumptions and information.

In the 2019-2020 IRP cycle, staff intends to develop a common data set to be utilized both in RESOLVE modeling and SERVM modeling, to the extent possible. In addition, RESOLVE and SERVM modeling will be conducted iteratively to arrive at an RSP recommendation informed by both. This parallel

[1] For detailed requirements, see Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure available here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K618/209618807.PDF

approach should cut down on the need to harmonize modeling assumptions and explain output differences in the next round. This will also allow the Commission to adopt an RSP and associated GHG target that is informed by both types of modeling analysis, leading to greater confidence in its results and the associated GHG emissions targets.

In addition to this basic structural improvement, Commission staff intends to consider the following potential improvements during the RSP development process for the next IRP cycle:

- Where feasible, use more granular, operating-state-specific, air pollutant emissions factors proposed by several parties to improve air pollutant estimates.
- Improve representation of lower GHG emissions from Northwest imports in lieu of the current fixed GHG credit for Northwest hydro.
- Consider scenarios or sensitivities on Northwest hydro delivering to CAISO or the Northwest.
- Incorporate new NERC/WECC BAL-002 standard into modeling of operating reserves.
- Revisit the net export limit assumption during RSP development.
- Thoroughly investigate and align curtailment and storage dispatch assumptions and results.
- Consider additional analytical work and value of reporting hourly average system emissions rates and marginal ELCC values by resource type, to further assist LSEs in portfolio planning.
- Improve the Clean Net Short calculator and other submission requirements, so that modeling inputs are cleaner and more consistent.

4. Schedule of Activities

The timing of a Commission decision on the PSP is constrained by a desire to have the Commission-adopted portfolio inform the CAISO TPP. Thus, a decision is needed by no later than the First Quarter of 2019. In addition, the 2019-2020 IRP process is due to kick off in early 2019 with the development of a new RSP and associated policy updates. To accommodate these timing considerations, the schedule in the table below indicates the expected timing of the next steps leading up to the development of a proposed decision on the PSP. Parties who attended the October 31, 2018 workshop should note that the schedule below is substantially different from the proposed schedule discussed there.

Activity	Date
Modeling Advisory Group office hours: short webinars for Commission staff to answer stakeholder questions on production cost modeling of the hybrid conforming portfolio.	November 14, 2018 1-2:30 p.m., and November 20, 2018 9:30-11 a.m.
Parties conducting modeling informally submit results to staff for presentation/discussion at workshop, if possible/desired.	January 3, 2019
Workshop: presentation of staff and modeling parties' production cost modeling and other analytical results.	January 7, 2019
Ruling seeking comment on proposed PSP and TPP scenarios recommended by Commission staff.	January 11, 2019
Comments in response to ruling on proposed PSP. Parties conducting their own modeling may also submit modeling results formally at this time, and must comply with Rules 10.3 and 10.4.	January 31, 2019
Reply comments in response to ruling on proposed PSP.	February 11, 2019
Proposed decision issued for comment.	March 2019

Commissions staff and/or ALJ rulings will further finalize and formalize the above dates and activities via notice to the service list of this proceeding and the Commission's Daily Calendar, as applicable.

IT IS RULED that:

1. Parties conducting production cost modeling to support recommendations to the Commission on the Preferred System Plan described in Decision 18-02-018 shall follow the guidelines outlined in the Attachment to this ruling.
2. Parties submitting production cost modeling results to the Commission shall follow the requirements of Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure.
3. The schedule for the portion of this proceeding related to production cost modeling and the development of the Preferred System Plan outlined in Decision 18-02-018 is as given in Section 4 of this ruling. Commission staff will provide more detailed information on dates and milestones, as they become available, to the service list of this proceeding.

Dated November 15, 2018, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

Attachment A:

Guide to Production Cost Modeling in the Integrated Resource Plan Proceeding

Revised November 13, 2018

Contents

I. Introduction

This document describes guidelines for production cost modeling in the Commission's Integrated Resource Plan (IRP) rulemaking (currently R.16-02-007), including modeling scope, conventions, analytical steps, and output reporting. Within a two-year IRP planning cycle, production cost modeling is intended to first inform development and validation of Reference System Plan capacity expansion modeling and subsequently evaluate the Preferred System Plan based on the aggregation of individual LSE IRP filings. This document describes a potentially durable analytical framework that could be replicated in future IRP cycles. As such, its scope includes specifying the technical aspects of IRP production cost modeling but does not include specifying the procedural process for engaging with parties to the proceeding. Procedural process will vary from cycle to cycle and is more appropriately specified via rulings from the assigned administrative law judge (ALJ).

II. Role of Production Cost Modeling in IRP

The primary purposes of production cost modeling in the IRP proceeding are to evaluate the system reliability, operational performance, emissions, and operating cost of a given projection of future resource mix and load. First, capacity expansion modeling will be used to narrow the projections of future resource mix and load into a Reference System Plan. Then, production cost modeling will be used to evaluate the Reference System Plan prior to Commission adoption. After adoption, load serving entities (LSEs) develop individual IRPs consistent with Commission direction and the Reference System Plan. LSEs may employ their own production cost modeling to develop their plans. After the LSEs file their individual IRPs with the Commission, staff will aggregate the LSEs' portfolios into one or more system portfolios. Finally, staff will use production cost modeling to evaluate the aggregated system portfolios and recommend a Preferred System Plan for Commission consideration. Other parties to the proceeding may also conduct their own modeling of the aggregated system portfolios and make recommendations to the Commission.

To the extent possible, entities performing production cost modeling to inform the IRP proceeding should adhere to the guidelines specified in this document and be consistent with the baseline assumptions in the "Unified RA [Resource Adequacy]/IRP Inputs and Assumptions" document referenced later in this document. Use of common guidelines and assumptions will help facilitate comparisons between the modeling results of different parties.

In general, stakeholders will have regular opportunities to participate in or comment on the various modeling activities in the IRP proceeding. Informally, Commission staff will engage with stakeholders via the Modeling Advisory Group,[1] a forum conducive to collaborative work between multiple parties and staff. Formally, parties to the proceeding can provide comment or submit modeling results according to the guidance and schedule determined by rulings from the assigned ALJ.

III. Modeling Scope and Conventions

Commission staff will use the SERVM[2] production cost model to measure operational performance and verify satisfaction of the Planning Reserve Margin[3] (PRM) requirement. This is the same model as used in the Resource Adequacy proceeding to calculate Effective Load Carrying Capability (ELCC).[4] Because the staff modeling work in both proceedings shares the same model, the detailed inputs and assumptions are described in a common document, the Unified RA/IRP Inputs and Assumptions document.[5] This document is updated annually at a minimum, or more frequently according to the needs of proceeding modeling activities. While the Unified RA/IRP Inputs and Assumptions document describes in detail the SERVM model inputs, the remainder of this document describes the modeling scope and conventions specific to IRP and the analytical steps to be taken. IRP production cost modeling work shall use the following scope and conventions:

A. Study years: every four years through the end of the study period (for the 2017-2018 IRP cycle: 2022, 2026, and 2030).
B. SERVM will be run using hourly time-steps.
C. Hourly system load shapes will be built up from fundamental consumption load shapes.
D. Behind-the-meter photovoltaics (BTM PV), Additional Achievable Energy Efficiency (AAEE), Time-of-Use (TOU) rate impacts, and electric vehicle (EV) load will be explicitly modeled as fixed shape

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[1] Modeling Advisory Group (MAG) notices are emailed to the proceeding service list – there is no separate list. Previous meetings and materials are posted here: http://www.cpuc.ca.gov/General.aspx?id=6442453968.

[2] Strategic Energy Risk Valuation Model – developed by and commercially licensed through Astrape Consulting.

[3] Refers to the system Resource Adequacy requirement based on each LSE's peak demand forecast plus a 15% planning reserve margin. See: http://www.cpuc.ca.gov/General.aspx?id=6307.

[4] The Resource Adequacy proceeding adopted ELCC values in D.17-06-027. The record of that proceeding includes proposals providing relevant background information on modeling and ELCC studies.

[5] The most recent version is posted here: http://www.cpuc.ca.gov/General.aspx?id=6442451972

Footnote continued on next page

generation (with both positive and negative values), rather than embedded in the load shapes. Transmission and distribution loss effects will be accounted for.

E. Loss-of-load event definitions and counting conventions, and operating reserve targets[6] shall be consistent with those used in the Resource Adequacy proceeding's production cost modeling with SERVM for ELCC calculations and as described in the Unified RA/IRP Inputs and Assumptions document. Multiple loss-of-load events occurring within one day shall count as one event for purposes of counting events towards a reliability target. The loss-of-load event occurs when regulation up/down (1.5% of hourly forecast load) or spinning reserves (3.0% of hourly forecast load) cannot be maintained. Loss-of-load hours (LOLH) shall count total hours of loss-of-load events whether consecutive or not.
F. Average portfolio ELCC values will be calculated on an annual basis only. This may differ from the methods used in the Resource Adequacy proceeding because of their requirement to produce monthly ELCC values for a monthly Resource Adequacy program.
G. The loss-of-load-expectation (LOLE) reliability target for calculating annual average portfolio ELCC values shall be 0.1 LOLE on an annual basis.
H. For ELCC calculations, the calibration of the system under study to the LOLE reliability target range may involve removing or adding generation.
    - Removal of generation to surface LOLE events in overbuilt systems shall be according to the following order:[7] Conventional thermal generators that have announced their retirement will be removed first. If LOLE remains below the target level, additional conventional thermal generation will be removed from California Independent System Operator (CAISO) areas in amounts proportional to service area load in each area. The oldest generation in each area will be removed first. No hydro generation or renewable generation will be removed.
    - Addition of generation to reduce LOLE events in underbuilt systems shall use the newest existing combustion turbine type generator as a proxy and will seek to distribute the added capacity to each service area proportionately. This is done because the LOLE results are meant to represent aggregate reliability across the CAISO. No calibration will be performed to areas outside the CAISO.

[6] SERVM's operating reserve targets are currently defined as a percent of hourly forecast load: regulation up/down is 1.5% each, load following up is 2.5%, load following down is 1.5%, spinning reserves is 3.0%, non-spinning reserves is 3.0%. If other parties elect to define operating reserve targets differently, it should be clearly documented and justified.

[7] Note that the order specified here is simply a modeling convention picking one systematic way to remove capacity for the sole purpose of calibrating a system to a target reliability level in order to perform ELCC calculations. The choice and order of removing units does not imply the units are likely to retire or should retire.

- Although the calibration step alters the system under study, this is a typical way of performing ELCC calculations and is not expected to significantly affect the ELCC measurement.

I. Average portfolio ELCC calculations will include all CAISO area wind and utility-scale solar including dynamically scheduled or dedicated import wind and solar generation, both existing and new, but exclude all BTM PV (i.e. BTM PV is left in the system and not part of the portfolio ELCC calculation). All CAISO wind and utility solar will be part of the ELCC calculation regardless of deliverability status.

J. The portfolio removed in an ELCC study (e.g. all wind and solar) is replaced with perfect capacity until the target LOLE is restored. Perfect capacity is a modeling proxy for generation with no operating constraints, e.g. always available, starts instantly, infinite ramp rate, no minimum operating level.

K. An annual CAISO area reserve margin will be calculated for each study year. The Net Qualifying Capacity (NQC) List[8] is used as a reference for this calculation. The conventions in the following table apply:

Component	Counting convention
Peak demand	California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) 1-in-2 year coincident annual peak sales forecast grossed up to system level
Existing non-wind, non-solar generation	Use current Net Qualifying Capacity values for August
New non-wind, non-solar generation	Use nameplate megawatts (MW)
New battery storage	Use nameplate MW. For batteries less than 4 hours duration at max output, derate by the ratio of duration hours / 4 hours.
Wind and solar (excluding BTM PV), existing and new, fully or partially deliverable	Multiply the annual average portfolio ELCC of all wind and solar, by the sum of the nameplate MW of only the fully or partially deliverable portion of wind and solar.
Energy-only resources	Do not count any resources assumed to be energy-only interconnection status. For example, to get wind and solar total NQC, subtract off the energy-only nameplate from the total nameplate of wind and solar before multiplying by the wind and solar average portfolio ELCC. Other resources besides wind and solar may also be designated as energy-only and these should also not be counted.
Unspecified or non-dedicated Imports	Use the CAISO maximum simultaneous import limit, adjusted downward for Existing Transmission Contracts

L. Reporting of operational performance should include: LOLE, LOLH, and EUE probabilistic reliability metrics[9], generation dispatch mix, emissions,[10] including estimating emissions from

[8] For the 2017-2018 IRP cycle, the March 15, 2018 version of the NQC List is used.

[9] LOLE (Loss of Load Expectation), LOLH (Loss of Load Hours), EUE (Expected Unserved Energy)

[10] The scope of GHG emissions reporting at the system level will be CAISO balancing area, California, and WECC-wide. CAISO area and California greenhouse gas (GHG) emissions accounting should align with California Air Resources Board, CEC, and CAISO production cost modeling practices to the extent possible. Air pollutant emissions will be reported in aggregate for plants located in disadvantaged community areas, the CAISO area, and California.

starts and stops, and NOx and PM2.5, RPS generation, curtailment patterns, production cost, and import/export flows.

IV. Reference System Plan Evaluation Steps

This section describes the steps that Commission staff will use to evaluate the Reference System Plan with production cost modeling. In the steps below, "study" or "studies" means production cost modeling runs. "As found" means the system under study is modeled with no additions or removals to the included generating units. "Calibrated LOLE" means the system under study had generating units added or removed to calibrate the LOLE reliability level to a desired target.

A. Conduct "As found" annual studies for study years (for the 2017-2018 IRP cycle: 2022, 2026, and 2030)
    1. Evaluate operational performance, including the metrics as described above
    2. Benchmark key metrics from SERVM (or other production cost model) with equivalent metrics from the capacity expansion model used to develop the system under study. (In the 2017-18 IRP cycle, this was the RESOLVE model's 2017 IEPR-updated 42 MMT core policy case.)
B. Conduct annual "Calibrated LOLE" studies for each study year
    1. Add or remove CAISO area generating units according to the convention described above until the LOLE reliability level is 0.1 LOLE on an annual basis.
    2. Report the generation added or removed in MW.
C. Conduct annual average portfolio ELCC studies for wind and utility solar for each study year
    1. Remove from the "Calibrated LOLE" system all CAISO area wind and utility solar (including dedicated import wind and solar generation, and including both deliverable and energy-only units).
    2. Incrementally add back perfect capacity until the annual LOLE reliability level returns to 0.1 LOLE.
    3. Calculate the average portfolio ELCC of wind and utility solar together as the ratio of perfect capacity added back to the nameplate wind and utility solar capacity that was removed.
    4. Report the annual average portfolio ELCC as a percent.
D. Calculate the CAISO system reserve margin and verify satisfaction of the PRM system reliability requirement in each study year
    1. Use the counting convention specified earlier in this document.
    2. Count all the generating units in the "As found" system, i.e. the reserve margin is being calculated for the "As found" system, not the "Calibrated LOLE" system.

Note that the production cost modeling exercises above do not include any marginal ELCC studies. Average ELCC studies are used to characterize the capacity value of a whole class or group of resources whereas marginal ELCC studies are used to characterize the capacity value of adding an increment of a given resource type. Until directed otherwise by the CPUC, any analyses conducted by LSEs or other interested parties that require the use of marginal ELCC values should use marginal ELCC estimates derived from the RESOLVE model. For reference, the values from the version of RESOLVE model used in the 2017-18 IRP cycle are shown in the table below. Note that RESOLVE groups BTM PV as part of the solar portfolio for which RESOLVE estimates marginal ELCC. This is in contrast to the average portfolio ELCC method used with the SERVM model described above, which does not include BTM PV in the ELCC calculation.

2017-18 IRP RESOLVE model marginal ELCC Values	**2018**	**2022**	**2026**	**2030**
Marginal Solar ELCC (including BTM PV as part of the solar portfolio)	13%	2%	2%	2%
Marginal Wind ELCC	29%	31%	30%	30%

V. Preferred System Plan Evaluation Steps

This section describes the steps that Commission staff will use to evaluate the Preferred System Plan with production cost modeling. The steps are similar to those taken to evaluate the Reference System Plan, but with additional steps to first aggregate individual LSE IRP data into one or more system portfolios to be studied.

A. Aggregate the individual LSE IRP data from their filings into one or more system portfolios to be studied with production cost modeling – generally this will be the sum of each LSE's Conforming or Preferred portfolios or a hybrid of the two. In the 2017-2018 IRP cycle, only Standard Plan filing data will be aggregated. This comprises about 97% of the total load represented by all IRP filers (i.e. about 3% of the total load is represented by the Alternative Plan filers).
    1. Validate consistency of reported generation unit and contract data
        a. Physical resource data is used to update the SERVM model dataset
            i. Verify new unit data does not exceed system potential or transmission capability
            ii. Reconcile reported existing unit data with SERVM existing units
            iii. Update data on whether a unit actually delivers to and is scheduled in CAISO
        b. Contract data is used to assess individual LSE and total system contract positions
            i. Verify contracts do not conflict/overlap or exceed the available physical resources
        c. Tabulate and summarize physical resource and contract data
            i. System-wide, by LSE type, by resource type, by year
    2. Validate individual loads add back up to system load

a. Using load or load-modifying resource data reported in the Standard New Resource Data Template and the Clean Net Short (CNS) Tool[11]
    i. Reconcile load shifts between LSEs
    ii. Verify no missing or extra load – individual load should add up to IEPR system load
    iii. Verify individual ESP loads (including load from Alternative Plan filers) sum up to IEPR direct access load
3. Staff posts the aggregated system portfolio(s) to serve as the common input for any party using production cost modeling to conduct their own evaluation. Data deemed confidential will be protected through the aggregation process or other means.

B. Conduct "As found" annual studies for every four years during study period. In the 2017-2018 IRP cycle, only year 2030 will be studied.
    1. Evaluate operational performance, including the metrics as described above
    2. Compare with results of the "As found" studies that were done to evaluate the Reference System Plan.

C. Conduct annual "Calibrated LOLE" studies for each study year
    1. Add or remove CAISO area generating units according to the convention described above until the LOLE reliability level is 0.1 LOLE on an annual basis.
    2. Report the generation added or removed in MW. In the 2017-2018 IRP cycle, the analysis stops here. No ELCC values will be calculated.

D. Conduct annual average portfolio ELCC studies for wind and utility solar for each study year
    1. Remove from the "Calibrated LOLE" system all CAISO area wind and utility solar (including dynamically scheduled or dedicated import wind and solar generation, and including both deliverable and energy-only units).
    2. Incrementally add back perfect capacity until the annual LOLE reliability level returns to 0.1 LOLE.
    3. Calculate the average portfolio ELCC of wind and utility solar together as the ratio of perfect capacity added back to the nameplate wind and utility solar capacity that was removed.
    4. Report the annual average portfolio ELCC as a percent.

E. Calculate the CAISO system reserve margin and verify satisfaction of the PRM system reliability requirement in each study year
    1. Use the counting convention specified earlier in this document.
    2. Count all the generating units in the "As found" system, i.e. the reserve margin is being calculated for the "As found" system, not the "Calibrated LOLE" system.

11 http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/GHG%20Calculator%20for%20IRP%20v1.4.5.xlsx

(End of Attachment A)