# Reference System Plan Production Cost Modeling

This section describes production cost modeling that CPUC staff will conduct as a higher fidelity assessment of the Reference System Plan. The analytical process described here also serves as guidelines for other parties to develop their own production cost modeling based assessment of the Reference System Plan. To the extent other parties wish to compare their assessments with CPUC staff’s, they should adhere as closely as possible to the assumptions, methods, and conventions used by CPUC staff.

CPUC staff will use the SERVM[[1]](#footnote-2) production cost model to evaluate operational performance and verify satisfaction of the Planning Reserve Margin[[2]](#footnote-3) (PRM) requirement. This is the same model as used in the Resource Adequacy proceeding to calculate Effective Load Carrying Capability (ELCC). Staff will also use the SERVM model to calculate marginal ELCC values intended for use by individual LSEs to develop their respective IRP Preferred Plans. Staff will also rely on this same production cost modeling framework to evaluate the Preferred System Plan. This later phase of analysis is described in TBD section, Standard of Review for LSE Plans.

Production cost modeling of the Reference System Plan serves several important purposes:

1. Benchmark the SERVM model and dataset to the RESOLVE model and dataset and characterize differences (e.g. differences in model granularity and common metrics). This distinguishes fundamental differences between RESOLVE and SERVM representation of the Reference System Plan from any additional differences that could be observed later when comparing SERVM studies of the Reference System Plan and the Preferred System Plan.
2. Evaluate the Reference System Plan’s operational performance (e.g. probabilistic reliability level, emissions, RPS generation, curtailment patterns, production cost, import/export flows, dispatch patterns, etc.) and verify satisfaction of the PRM system reliability requirement (using QC and average ELCC as described later). This evaluation serves to establish the Reference System Plan as a reliable standard for comparison with the Preferred System Plan.
3. Repeat this evaluation of operational performance and verification of PRM satisfaction on an alternative RESOLVE case, for example the 50% RPS Default case,[[3]](#footnote-4) such that it is available for use in any of the CAISO’s 2018-19 Transmission Planning Process (TPP) studies.
4. Reevaluate the performance of the Reference System Plan (and any other alternative RESOLVE case) after incorporation of the 2017 IEPR demand forecast (expected to be adopted by the California Energy Commission (CEC) in January 2018) or any other data update that may be warranted. SERVM modeling *without* *incorporating* the 2017 IEPR is still required to be able to benchmark with RESOLVE cases because RESOLVE modeling relied on the previous IEPR (2016 IEPR Update demand forecast). SERVM modeling *incorporating* the 2017 IEPR is also required because the LSEs will be building the Preferred System Plan based on the 2017 IEPR. The CAISO’s 2018-19 TPP will also use the 2017 IEPR.
5. Determine the marginal ELCCs of new wind and solar resources implied by the Reference System Plan and provide these values to LSEs to guide the design of their respective IRP Preferred Plans.

## Modeling Scope and Conventions

The following describes the scope and conventions that staff will use for production cost modeling of IRP system plans with the SERVM model.

1. Study years: 2022, 2030. The RESOLVE cases explicitly provide results for years 2018, 2022, 2026, and 2030. Staff has limited resources and time to conduct modeling so a compromise is production cost modeling of two of the four years from the RESOLVE cases.
2. Loss-of-load event definitions and counting conventions, and operating reserve targets shall match those used in the Resource Adequacy proceeding’s production cost modeling with SERVM for ELCC calculations. 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.
3. For ELCC calculations, use an annual loss-of-load-expectation (LOLE) reliability target range of 0.095 to 0.105 in total covering the four summer months of the year (June through September). No effort will be made to surface LOLE outside of the four summer months, and each of the summer months will be calibrated to an equal LOLE (each month will be calibrated until there is about 0.025 LOLE in each of the four summer months). This is consistent with the “Levelized monthly LOLE” approach used in the Resource Adequacy proceeding’s ELCC calculations, albeit only focusing on the summer months.
4. 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 follow an order of removal described below. 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 CAISO areas ranked by age of the facility. The oldest one will be removed first, continuing in order of age. No hydro generation or renewable generation will be removed.
* Addition of generation to reduce LOLE events in underbuilt systems shall use perfect capacity as additions. 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.

1. BTM PV will be explicitly modeled as generation, rather than part of the load forecast, consistent with its treatment in the RESOLVE model.
2. Average ELCC calculations will include both utility-scale solar and BTM PV together.
3. For reserve margin calculations, the counting of effective capacity shall use the conventions in the following table:

|  |  |
| --- | --- |
| Component | Counting convention |
| Peak demand | IEPR 1-in-2 annual peak consumption forecast adjusted for load-modifier impacts but excluding BTM PV impact |
| Existing non-wind, non-solar | Use current Net Qualifying Capacity values |
| New non-wind, non-solar | Use same conventions as the RESOLVE model |
| Wind and solar (including BTM PV), existing and new | Calculate the average portfolio ELCC of these resources combined |

1. Hourly load shapes will be built up from fundamental consumption load shapes and shapes for various load modifiers such as AAEE, TOU rates, and EV charging patterns.
2. SERVM will be run using hourly time-steps.
3. Unless superseded by a specific guideline called out in this document, staff will follow the modeling guidelines in the ALJ Ruling Directing Production Cost Modeling Requirements issued in R.16-02-007 on September 23, 2016.

## Modeling Steps (Order of Studies)

The following describes the steps (order of studies) that staff will use for production cost modeling of IRP system plans with the SERVM model. In the steps below, “study” or “studies” means production cost modeling runs.

1. Calibrate RESOLVE’s Reference System Plan representation and the SERVM dataset’s representation (e.g. total system portfolio, topology, operational constraints)
   1. Produce a report comparing the RESOLVE and SERVM models and inputs, characterizing areas of alignment and differences
   2. Post the SERVM dataset representing the Reference System Plan
   3. Post the SERVM dataset representing the alternative RESOLVE case, if any
2. Conduct Reference System Plan studies for years 2022 and 2030
   1. Evaluate operational performance, including quantifying the LOLE level before any calibration (addition or removal of generation)
   2. Benchmark key metrics from SERVM with equivalent metrics from RESOLVE as a check on input or modeling differences and their projected impact on results
   3. Calibrate the Reference System Plan to the desired LOLE level for calculating ELCC values, noting the quantity of generation added or removed
   4. Calculate the average portfolio ELCC of wind and solar (utility-scale + BTM PV)
   5. Calculate the reserve margin and verify satisfaction of the PRM system reliability requirement
   6. Repeat of B1-B5 for the alternative RESOLVE case, if any
   7. Calculate the marginal (not average) ELCC values of the following to guide LSE Plan development:
      * 1,000 MW block of new wind facilities
      * 1,000 MW block of new solar (utility-scale) facilities

Values for only one location (the CAISO balancing area), one solar technology type (single-axis tracking), and two years (2022, 2030) will be calculated. Future IRP cycles may consider additional granularity and years. The RESOLVE model is also capable of producing estimates of marginal ELCC of wind and solar for modeled years. These can be benchmarked with the marginal ELCC values produced using the SERVM model as a sanity check.

1. Update the SERVM dataset to incorporate the 2017 IEPR demand forecast[[4]](#footnote-5)
   1. Post the updated SERVM dataset representing the Reference System Plan
   2. Post the updated SERVM dataset representing the alternative RESOLVE case, if any
2. Conduct updated Reference System Plan studies for years 2022 and 2030
   1. Repeat all studies in B. using the 2017 IEPR demand forecast
3. Staff may consider running additional sensitivities of any of the studies above (e.g. use different reserve requirements or net exports constraints)

In the evaluation of operational performance (B1) step, staff will be reporting the key metric of GHG emissions. Total CAISO balancing area annual emissions will be the primary measure of whether the Reference System Plan meets emissions requirements. California and WECC-wide emissions can also be reported from the model.

In the calibration (B3) step, if generation had to be added, the quantity added would be noted and reconsidered during the evaluation of the Preferred System Plan. This is because the Preferred System Plan may introduce other system changes that effectively reduces or increases the quantity of generation that must be added to achieve the target probabilistic reliability level range. Note that while this exercise may be useful in characterizing any shortfall in reliability, the analysis actually determining whether any system reliability-driven additional procurement is necessary is step B5, the reserve margin calculation and verification of PRM satisfaction, on the Preferred System Plan (for details see TBD section, Standard of Review for LSE Plans).

In this IRP cycle, there is insufficient time to complete Reference System Plan production cost modeling and have results vetted with stakeholders prior to the expected Reference System Plan adoption at the end of 2017 as formal guidance to LSEs for developing individual LSE Plans (the Preferred Plans). Instead staff will complete and vet the production cost modeling results with stakeholders in Q1 of 2018, in parallel with the LSEs developing their Preferred Plans. This parallelization of processes may be advantageous because it permits incorporation of the 2017 IEPR demand forecast. Staff views this staging of processes as the most efficient way to accomplish the necessary modeling within the tight schedule of this IRP cycle.

As staff is responsible for providing marginal ELCCs to inform LSE Preferred Plan development, this specific deliverable must be completed by early 2018 in order to be useful to LSEs. This may not be possible if Reference System Plan production cost modeling and results are being vetted with stakeholders in Q1 of 2018. As an interim solution for this IRP cycle, staff will provide marginal ELCCs derived from the RESOLVE model so that LSEs can proceed with developing their Preferred Plans without waiting for the SERVM production cost modeling-based marginal ELCCs.

# Standard of Review for LSE Plans

## Alternative LSE Plans

For Alternative Plans, staff proposes that the review process consist of verifying the LSE’s eligibility to file an Alternative Plan and that the submitted IRP meets the relevant requirements.

## Standard LSE Plans

For Standard Plans, Energy Division staff, including the Energy Resource Modeling group, will review each LSE Plan both individually and in aggregate, as described in the steps below.

1. Verify all required sections are present, and each section includes all required components, as itemized above under General Requirements and Technical Requirements.
2. Verify all required types of data are provided and data meets the format requirements, as described above in the Data section listed under General Requirements.

Second, staff will conduct a substantive review of LSE Plans following the standards and framework described below. The review includes a series of production cost modeling steps which are detailed in the subsequent subsection.

1. The Commission anticipates that some circumstances would require it to intervene and direct an LSE to amend its plan. Three potential circumstances are:
   1. An electrical corporation’s (IOU’s) plan does not demonstrate a sufficient strategy for procuring best-fit and least-cost resources to satisfy the portfolio needs identified by the Commission or that its customers will be served with just and reasonable rates
   2. An LSE’s plan does not satisfy pre-determined requirements (paraphrased from PU Code Section 454.52(a)(1))
      1. Meet GHG reduction targets established by CARB
      2. Achieve the RPS program’s renewable generation target[[5]](#footnote-6)
      3. Minimize impacts on ratepayers’ bills
      4. Ensure system and local reliability
      5. Strengthen the bulk transmission and distribution systems, and local communities, and enhance demand-side energy management
      6. Minimize localized air pollutants prioritizing disadvantaged communities
   3. An LSE’s plan has a substantial likelihood of imposing significant costs on other California LSEs
2. Staff will evaluate LSE plans for circumstances (a) and (b) either by considering each LSE plan individually or the aggregate of LSE plans as a whole.

|  |  |
| --- | --- |
| (a) | Evaluate if an IOU’s plan deviates from the Reference System Plan and if so, determine if the IOU has sufficiently justified the deviation. |
| (b)(i) | Measure the total emissions of the Preferred System Plan with production cost modeling. |
| (b)(ii) | Measure the total renewable generation of the Preferred System Plan with production cost modeling. Review an LSE’s demonstration of how its plan aligns or deviates from its RPS plan. |
| (b)(iii) | Review an LSE’s cost impact analysis on its own ratepayers. |
| (b)(iv) | Measure the Preferred System Plan reserve margin. Review an LSE’s assessment of how it will meet the local capacity needs projected in the most recent CAISO Transmission Plan. |
| (b)(v) | Review an LSE’s assessment of how it will meet these requirements. |
| (b)(vi) | Review an LSE’s quantitative evidence of how its plan satisfies statutory requirements regarding disadvantaged communities. |

1. In circumstance (c), staff must consider interactions among LSE plans because (c) indicates an “externality” is present, i.e. a situation where current market rules might not result in appropriate valuation of necessary resource attributes. If an externality is large enough, Commission intervention may be justified, e.g. to mitigate the likelihood of significant imposition of costs from one LSE onto others. As stated in Chapter 4 of the May 16, 2017 Staff Proposal on Process for IRP, the CPUC should be guided by the principle of market efficiency:
   1. To the extent that the market can be reasonably expected to produce the desired outcome, there would be no reason for the CPUC to intervene.
   2. To the extent that there are material barriers to market solutions for any relevant market actors, the CPUC would act to address market deficiencies.

In the absence of a significant unaddressed externality, LSEs bear all the costs of their own decisions and no further Commission intervention is required.

1. To determine whether a significant externality is present and requires Commission intervention, the Commission must first define each specific potential externality.
   1. In general, it is expected that the Commission will find few instances of externalities significant enough to justify intervention. The CAISO's multi-stage market is designed to provide the right signal, at the margin, to resources for the value of their energy and capacity. The CAISO continually monitors its market to ensure efficient operation.
   2. Ensuring system and local reliability is one example of a potential externality – without appropriate standards or market signals, LSEs might not procure sufficient capacity to ensure reliability, choosing to forego capacity contract costs to rely instead on the market. This is one example where the Commission has already taken action to avoid potential externalities by enforcing system and local reliability standards via the Resource Adequacy and LTPP mechanisms. Going forward the IRP should continue to coordinate with the Resource Adequacy program and retain the mechanisms for ensuring long term reliability from the LTPP and in doing so, the Commission believes no further intervention is required to ensure system and local reliability at this time.
   3. As new externalities arise, the appropriate requirements should be added to the CPUC’s review of LSE plans in future IRP cycles. Examples that may become significant in the future include:
      1. Future reliability products identified and defined by the CAISO
      2. Changes or additions to the requirements in the Resource Adequacy program

# Preferred System Plan Production Cost Modeling

This section describes production cost modeling that CPUC staff will conduct to evaluate the Preferred System Plan. The analytical process described here also serves as guidelines for other parties to develop their own production cost modeling based assessment of the Preferred System Plan. To the extent other parties wish to compare their assessments with CPUC staff’s, they should adhere as closely as possible to the assumptions, methods, and conventions used by CPUC staff.

CPUC staff will use the SERVM[[6]](#footnote-7) production cost model to evaluate operational performance and verify satisfaction of the Planning Reserve Margin[[7]](#footnote-8) (PRM) requirement. Staff will follow the same modeling scope and conventions as will be used to evaluate the Reference System Plan, and will follow a similar set of modeling steps, explained below.

## Modeling Steps (Order of Studies)

The following describes the steps (order of studies) that staff will use for production cost modeling of IRP system plans with the SERVM model. In the steps below, “study” or “studies” means production cost modeling runs. All studies will use the 2017 IEPR demand forecast.

1. Aggregate the individual LSE Preferred Plans into the Preferred System Plan SERVM dataset
   1. Map the resources in each individual LSE Plan to resources in the SERVM representation of the Reference System Plan and create new LSE resource types in the SERVM dataset as needed
   2. Organize the SERVM dataset such that each LSE Plan can be swapped in and out of the Preferred System Plan in an automated fashion
   3. Post the SERVM dataset representing the Preferred System Plan
2. Conduct Preferred System Plan studies for years 2022 and 2030
   1. Evaluate operational performance, including quantifying the LOLE level before any calibration (addition or removal of generation)
   2. Compare and report results of step B(1) with the equivalent study of operational performance performed with the Reference System Plan
   3. Calibrate the Preferred System Plan to the desired LOLE level for calculating ELCC values, noting the quantity of generation added or removed
   4. Calculate the average portfolio ELCC of wind and solar (utility-scale + BTM PV)
   5. Calculate the reserve margin and verify satisfaction of the PRM system reliability requirement
3. Quantify any shortfall in satisfying the PRM system reliability requirement and allocate proportionate responsibility to the LSEs

In the aggregation (A1) step, the process must ensure that no resources are double-counted or under-counted, and that the aggregate of new resources selected by LSEs does not exceed the available resource potential. This step may require staff to make additional data requests to LSEs to resolve any issues. The resources of each LSE Plan in the SERVM dataset must be organized in such a way that permits systematic sequential studies of the Preferred System Plan with an LSE Plan included or excluded. This provides a mechanism to isolate the effects of an individual LSE Plan on the operational performance of the Preferred System Plan, should such an analysis be necessary.

In the evaluation of operational performance (B1) step, staff will be reporting the key metric of GHG emissions. Total CAISO balancing area annual emissions will be the primary measure of whether the Preferred System Plan meets emissions requirements. California and WECC-wide emissions can also be reported from the model.

In the calibration (B3) step, if generation had to be added, the quantity added would be noted, however, the analysis actually determining whether any system reliability-driven additional procurement is necessary is step B5, the reserve margin calculation and verification of PRM satisfaction.

If step C is necessary then staff would quantify the shortfall in MW of qualifying capacity and allocate proportionate responsibility to the LSEs. Two options for allocating responsibility are as follows:

Option A: Allocate procurement responsibility proportionally by each LSE’s ratio of their peak load to total CAISO peak load to procure GHG-free resources that in aggregate would provide the equivalent qualifying capacity.

Option B: Direct the IOUs to procure GHG-free resources that in aggregate would provide the equivalent qualifying capacity. The Cost Allocation Mechanism will distribute the cost of this procurement to all benefiting LSEs.[[8]](#footnote-9) To the extent that additional procurement is authorized for an IOU, the Commission will ensure that the affected CCAs are given an opportunity to submit proposals for satisfying their portion of the renewable integration need, consistent with Section 454.51.

1. Strategic Energy Risk Valuation Model – developed by and commercially licensed through Astrape Consulting [↑](#footnote-ref-2)
2. 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> [↑](#footnote-ref-3)
3. The RESOLVE model case representing achievement of a 50% RPS in 2030 and no further procurement driven by firm GHG reduction goals. [↑](#footnote-ref-4)
4. Note that the Reference System Plan and 50% RPS Default case resource portfolios will not be recreated in RESOLVE based on the 2017 IEPR demand forecast. Thus only the load and demand-side resources will be updated in the SERVM model to align with the 2017 IEPR. [↑](#footnote-ref-5)
5. SB 350 set the target at 50%. The target may increase to 60% either through passage of SB 100 or the CPUC’s own actions administering the RPS program. [↑](#footnote-ref-6)
6. Strategic Energy Risk Valuation Model – developed by and commercially licensed through Astrape Consulting [↑](#footnote-ref-7)
7. 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> [↑](#footnote-ref-8)
8. CAM is a regulatory process for allocating capacity costs of utility procurement across all benefitting customers. More information is available at: http://www.cpuc.ca.gov/General.aspx?id=6949. [↑](#footnote-ref-9)