Resource Adequacy Forecast Adjustment(s) Allocation Methodology

Miguel Cerrutti

Demand Analysis Office – California Energy Commission

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The California Public Utilities Commission (CPUC) Resource Adequacy (RA) program requires its jurisdictional load-serving entities (LSEs) to demonstrate through monthly and annual compliance filings that they have sufficient capacity commitments to satisfy demand at all times, so to ensure system reliability.

Monthly and annual system RA requirements are based on load forecast data filed annually by each LSE and adjusted by the California Energy Commission (CEC). The adopted forecast methodology is known as the “best estimate approach” and requires jurisdictional and non-jurisdictional LSEs to submit, on an annual basis, historical hourly peak load data for the preceding year and monthly energy and peak demand forecasts for the coming compliance year based on reasonable assumptions for load growth and customer retention. Following this annual LSE submission, the CEC makes a series of adjustments to the LSE submitted load forecasts before allocated the final load forecast to be used for RA compliance.

This paper is broken into four parts. The first section briefly describes the adjustment made to the each LSEs year-ahead forecast to arrive at the final load forecast used for RA compliance. The second section goes into greater detail on how the coincident adjustment methodology is done. The third section details the weather normalization methodology done to the CEC short-term load forecast. And the final section reviews the pending implementation issues.

1. **Adjustments made to CPUC- jurisdictional LSE year-ahead forecasts**
2. Coincident adjustment - The CEC first calculates LSE specific monthly coincident factors[[1]](#footnote-1) using historic hourly load data (filed by the LSE). The adjustment factors are calculated by comparing each LSE’s historic hourly peak loads to the historic coincident California Independent System Operator (CAISO) hourly peak loads. These factors are used to make each LSE’s peak load forecast reflective of the LSE’s contribution to load at the time of CAISO’s peak load.
3. CEC Adjustment for difference in service area forecasts (plausibility adjustment) - The CEC then reconciles the aggregate of the jurisdictional LSEs monthly peak load forecasts against the CEC’s monthly one-in-two, short-term, weather normalized[[2]](#footnote-2) peak-load forecast, for each investor owned utility (IOU) service area. This is done to evaluate the reasonableness of the LSEs forecasts. The CEC forecast, used in this reconciliation, is adjusted for; coincidence, incremental effects of energy efficiency, demand response programs, and distributed generation. As a part of the reconciliation the CEC may adjust individual IOU forecasts, if the aggregate LSE forecasts are significantly inconsistent with CEC’s forecasts for reasons other than load migration. Additionally, the CEC compares individual LSE forecasts to current peak demand estimates, (i.e., August month ahead forecast) and adjusts them if the difference is greater than a tolerance threshold.
4. Energy Efficiency (EE)/Distributed Generation (DG)/Demand Response (DR) Adjustment -Prorated adjustments are then made to the LSEs forecasts to account for demand side energy savings that are paid for through distribution charges (energy efficiency, distributed generation, and demand response). Time of Use, Permanent Load Shifting, Critical Peak Pricing, and Peak Time Rebate programs all decrease the CEC load forecast and are listed as downwards adjustments as part of the DR adjustment. The downwards effects of these programs impact IOU forecasts only or load forecasts for all bundled and non-bundled customers depending on how the costs of the program are recovered.
5. Pro rata adjustment to match CEC forecast within 1% - Lastly, in the event that total LSEs forecasts are more than 1% divergent from the CEC’s monthly weather normalized forecasts a pro rate adjustment is made to bring it back within 1%.
6. **Coincidence factors**

A LSE-specific monthly coincidence factor is calculated as the ratio of the LSE’s peak load at the time and hour of the five highest monthly CAISO’s system peak loads to the specific LSE’s actual non-coincident peak load in any given month. LSE-specific coincidence factors are computed for each month and transmission access charge (TAC) area based on historical hourly loads for the latest 1-3 years.

The median monthly coincidence factor is selected from the five available as the LSE-specific monthly coincidence factor. The monthly coincidence factors are applied, to each LSE’s year-ahead monthly peak forecasts, to adjust the LSE’s non-coincident peak to a forecast of the LSE’s peak coincident with the CAISO system peak. In month-ahead forecasts, the coincidence factor is also applied to the non-coincident peak of migrating load. Therefore both the year-ahead and month-ahead forecasts are being adjusted by coincidence factors in determining RA obligations.

Coincidence factors vary slightly based on load composition. The CAISO system hourly peaks are driven mainly by the residential sector, which is the largest energy consuming sector of the economy and the most sensitive to weather. Therefore, the median coincident factor based on historical hourly loads for the latest year seems appropriate for LSEs with large residential weather sensitive loads. However, for LSEs with large commercial, industrial, and/or pumping loads that do not mirror the CAISO system hourly peaks median coincident factors are not as useful. In response to coincidence factor sensitivity and variability across LSEs the CEC does the following

* For LSEs with load shapes that are relatively stable over time and/or correlated with the system loads, the CEC uses one year of current load data to assess coincidence with CAISO system peak load stability.
* For LSEs with load shapes that change significantly over time and/or are not correlated with the system loads, CEC uses at least three previous years of data, instead of one year, to assess coincidence with CAISO system peak loads stability over time. Additionally, the CEC calculates coincidence factors based on average hourly peak loads. After selecting the hours for the corresponding CAISO highest five peak loads by month, LSE-specific coincidence factors are calculated as the mean of the coincidence factors over the range of peak hours over the days of the month.
* For LSEs that experience slightly higher load responses to more than normal weather patterns the CEC uses weather normalized coincidence factors. The analysis consists of a daily time-series regressive model to normalize daily LSE and system peaks to weather variables. This would result in monthly normalized non-coincident peaks for each year. Within each month and year, LSEs normalized coincident peaks corresponding to the day of the system maximum weather normalized system peak would then be obtained. For each LSE, the monthly normalized coincidence factor would be computed as the ratio of the monthly coincidence peak to the monthly non-coincident peak, resulting in monthly normalized coincident factors for each of the three years. Additionally, for comparison purposes, the CEC runs simultaneously an alternative simpler approach to calculate coincidence factors. The approach consists of running a statistical regression analysis of coincidence factors on weather at the time of coincident peak. Using this value from any year as the input, the regression analysis then would provide the expected coincidence factor.

Once the coincidence factors are established in the year-ahead process, they are held constant for the month-ahead process. The CEC also develops coincidence factors for non-jurisdictional LSEs in the CAISO using the methodology described above. The LSEs submit non-coincident peak forecasts to the CEC and the CEC develops the coincidence factors and provides year-ahead and month-ahead forecasts to the CAISO for all CAISO LSEs. Non-coincident forecasts are provided to the CAISO congestion revenue right allocation process and coincident forecasts to the reliability process. This ensures that both processes have consistent forecasts.

1. **Weather normalization short term load forecast**

Weather peak normalization adjusts peak loads so they represent peak loads under normal weather conditions; it factors out the variations in weather allowing for comparison of peak loads over time under different weather conditions. CEC relies on its weather normalized process to develop the short-term peak-load forecasts that are used to reconcile the aggregate LSEs year-ahead forecasts in each IOU area for RA compliance. The current weather normalization process consists of regressing summer peak loads (June 1 to September 30) on weather and calendar effects, i.e., daily temperatures and time dummies. The regression estimates are then used with historical weather patterns in a Monte Carlo simulation to produce a distribution of summer peak loads of which the median represents the weather normalized summer peak load.

The key input in performing the normalization is defining the timeframes to be used in estimating peak load responses to temperature and in defining normal weather conditions in the Monte Carlo simulation. The historical process (used up until this year) used the following timeframes: first, the current one year of CAISO’s Energy Management System (EMS) data from TAC areas to estimate peak load responses to weather and second, 60 years of weather data to define normal weather conditions.

In an attempt to better capture peak load’s weather sensitivity and adequately represent the latest weather patterns, the timeframes were changed this year to include four years of CAISO’s EMS data to estimate peak load sensitivity to weather and 30 years of weather data to define normal weather conditions. The new timeframes and the current weather normalization process are detailed in two broad steps below.

First, the CEC develops a time-series regressive equation relating daily peak load to daily weather conditions and calendar effects using the three previous years of EMS data, i.e., excluding the current year. The best combination of weather and calendar effects and functional form based on in-sample (three previous years) and out-of-sample (current year) goodness of fit statistics from the first regression is used to develop a second time-series regressive equation using the current year and the previous two years of EMS data.

Second, from the second fitted time-series regressive model, the estimates are then be multiplied by the corresponding 30 years of historical weather data to build a Monte Carlo simulation of expected peak loads for each summer day and historical weather year. Every peak load in each of those days is assumed on a weekday and non-holiday, i.e., peak producing days. The probability distribution of maximum annual daily peak load for each of the 30 historical weather years provides a measure of the uncertainties associated with the volatility of the yearly peak demand responses to realistic temperature patterns that prevailed across the TAC areas for the last 30 years. The one-in-two or the 50th percentile of the probability distribution represents the most likely weather normalized peak loads. The one-in-ten or the 90th percentile to the 50th percentile expresses the peak demands at extreme temperatures.

The one-in-two weather normalized peak loads by TAC areas form the base to develop Integrated Energy Policy Report (IEPR) peak loads at the IOUs service areas after they have been adjusted downward by critical peak pricing, peak time rebate and non-event based demand program impacts (real time or time of use pricing and permanent load shifting). In order to avoid double counting, it is necessary that the IOUs provide detail information about the event and non-event based demand response programs included in the data supplied to CEC. The one-in-ten weather normalized peak loads by TAC areas projected two-year ahead using the latest economic and demographic information are provided to the CAISO by the end of the current year to be used in its two-year ahead analysis of local capacity requirements. This means that the short-term peak-load forecasts that CEC uses to reconcile the aggregate LSEs year-ahead forecasts in each IOU area for RA compliance are locked two-years out.

In light of the increased volatility of peak and weather in recent years and the possibility that weather changes may become persistent, the peak to weather relationship should be reviewed and updated regularly to ensure it maintains consistency with future weather trends. The process should include investigating the boundaries of applicability of CEC’s developed time-series statistical models, variable selection process, functional form, and their application to explain better peak load sensitivities to weather and to account for weather fluctuations over time.

1. **Pending Implementation Issues**

It not clear whether or not demand response impacts are embedded in LSE’s hourly loads that are used in calculating coincident adjustment factors. In the future all LSEs need to provide additional information about the extent and type of demand responses embedded in the hourly data. To better estimate LSEs contributions to CAISO system peak, CEC requires in addition to the LSEs hourly loads the quantity of hourly demand response by program embedded in them.

Additionally, it is not clear what demand programs are included and not included in LSEs year-ahead forecast. LSEs need to specifically indicate on their year-ahead load forecasts whether a demand program (demand response, energy efficiency, and distributed generation) is being included and how it is being accounted for in their forecasts. CEC will then be able to credit the impacts to the LSEs preventing double counting and better deriving capacity obligations for each LSE.

1. Adopted in D.12-06-025. [↑](#footnote-ref-1)
2. Weather normalization methodology is detailed below. [↑](#footnote-ref-2)