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APPENDIX A

APPENDIX A

Summary of Load Forecast Process under Slice of Day Resource Adequacy (RA) Framework

This document summarizes the RA load forecast adjustment process adopted in Decision (D.) 04-10-35 and subsequently modified in D.05-10-042, D.09-06-028, D.10-03-022, D.10-12-038, D.11-06-022, D.12-06-025, D.14-06-050, D.15-06-063, D.16-06-045, D.17-06-027, D.18-06-030, D.19-06-026 and D.23-04-010. This document incudes a high-level summary of the process, including references to compliance materials, a summary of the binding load forecast component of the framework, and a summary describing the process the California Energy Commission (CEC) staff follows to develop adjusted load-serving entity (LSE) forecasts for the RA Slice of Day (SOD) program.

I. Background

The RA program requires LSEs to submit annual historical load data and year-ahead load forecasts to Energy Division and CEC. CEC then makes a series of adjustments to the LSE-submitted load forecasts to account for plausibility, coincidence, and demand side impacts and to ensure that the aggregate LSE load forecast is within 1% of the adopted CEC demand forecast developed through its Integrated Energy Policy Report (IEPR) process. Monthly and annual system RA requirements are based on load forecast data filed annually by each LSE and adjusted by CEC. To develop these forecasts, both jurisdictional and non-jurisdictional LSEs must submit historical hourly peak load data for the preceding year (in March), and monthly energy and hourly worst day (peak-day) demand forecasts for the coming compliance year (in April and May). When developing demand forecasts, LSEs must use a "best estimate approach" that is based on reasonable assumptions for load growth and customer retention. CEC makes adjustments to these submitted forecasts which are then distributed to LSEs as part of their initial year-ahead allocations. LSEs are also allowed to file a revised year-ahead load forecast in August that only accounts for load migration. Following the revised August submittals, Energy Division sends out final LSE load forecasts as part of the final year-ahead allocations.

Additionally, LSEs are required to submit an intra-year revised load forecast (in February) for compliance months June–December that accounts for load migration. The intra-year submittals along with the year-ahead load forecast inform the month-ahead RA system requirements for June–December.

LSE load forecast instructions, templates and schedules can be found on the Commission's RA compliance website.[1]

II. Binding Load Forecast Process Summary

D.19-06-026 adopted a binding load forecast process for the RA program. The decision states that "[i]n an effort to improve predictability of load and RA requirements, Energy Division proposes a Binding Notice of Intent (BNI) process that 'locks in' RA requirements based on load forecast assumptions that an LSE can reasonably predict or control."[2] The BNI would apply to the RA program alone and would not impact an LSE's legal ability to serve load. The BNI "would simply set year ahead RA requirements at a benchmark level that LSEs" and other stakeholders, including the Commission, California Independent System Operator (CAISO), and CEC, could rely on to remain unchanged (other than to account for load migration).

Specifically, the proposed BNI process is described as follows: "An LSE's initial year ahead load forecast will serve as the BNI for that LSE in the following year. To account for unforeseen circumstances or new or relevant information in the forecasting process, CEC will extend the deadline for revisions to the initial forecasts to May 15. Once the initial load forecast is submitted, the LSE is responsible for the RA capacity implied by the initial load forecast – after any adjustments by CEC and for load migration - regardless of additional changes in an LSE's implementation to new customers. Additionally, the Commission and CEC will add plausibility review triggers to the forecast adjustment process, which if triggered, may require additional documentation, forecast revisions to better match an implementation plan, or forecast revisions to account for load migration."[3]

The 2019 decision adopts Energy Division's proposal by stating that "[t]he Commission is persuaded that Energy Division's proposed process will encourage effective forecasting in the year-ahead process and discourage modifications to load forecasts for reasons other than unpredictable load migration. However, the Commission renames Energy Division's proposal as the Binding Load Forecast (BLF) process to avoid confusion with the "binding notice of intent" described in D.04-12-048 and D.05-12-041 in relation to [community choice aggregators (CCAs)]. Accordingly, the Commission adopts Energy Division's proposal for a Binding Load Forecast process to lock in RA

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

2 D.19-06-026 at 28.

3 *Id*.

requirements based on load forecast assumptions that an LSE can reasonably control or predict, as well as the proposed plausibility review triggers."[4]

D.19-06-026 also adopted a meet and confer process:

> [W]e adopt a meet and confer requirement whereby: (1) a meeting between LSEs that anticipate load migration shall occur reasonably in advance of the filing deadline for initial year ahead forecasts (April of Year 1), and (2) in each LSE's initial year ahead forecast filing, each LSE shall briefly describe the dates of meetings with other LSEs to discuss load migration, any agreements, and any continued areas of disagreement. For the purposes of this requirement, we define "agreement" to mean: where two LSEs that expect load migration between themselves shall adjust their forecasts by the same MW amount, regardless of whether their respective forecasting methods are identical. We decline to otherwise specify where and how the meetings shall occur.[5]

The Commission also adopted a definition for load migration: "The Commission adopts a modified definition of 'load migration' for the purposes of the RA program to mean load effects that:

> (1) Result from one or more customers' retail electric service transferring directly from one LSE to another LSE in the same Transmission Access Charge (TAC) area, and
>
> (2) An LSE cannot reasonably predict and include in an implementation plan or in an initial year-ahead load forecast."[6]

"Further, 'load migration' shall not include the following non-exhaustive list of events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or force majeure events, transfers of load out of the TAC area, or forecasting errors."[7]

III. Slice of Day (SOD) Load Forecast Methodology

The shift to the SOD framework from monthly peak required methodology changes to the previous RA peak demand forecast method, including changes to coincidence and

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4 *Id*. at 29.

5 *Id*. at 32.

6 *Id*. at 25.

7 *Id*.

LSE-specific adjustments, and the addition of an intermediate pro-rata step. The steps below document the complete SOD load forecast adjustment process.

A. Step 1: Reference Forecasts

The reference forecast, or control total for the total of California Public Utilities Commission (CPUC)-jurisdictional LSEs, is drawn from the most recently adopted IEPR Planning Scenario forecast. Under the SOD framework, the "worst day" is the day within a given month that exhibits the highest CAISO system peak. The worst day is used to establish SOD RA obligations for LSEs.

For Southern California Edison (SCE) and Pacific Gas and Electric Company (PG&E), the CPUC-jurisdictional reference forecast is derived from the IEPR forecast by subtracting estimated non-CPUC jurisdictional loads (primarily publicly owned utilities (POUs)) from the TAC area forecasts. CEC receives historical hourly loads and year-ahead RA forecasts from all LSEs in CAISO. The POU load forecast estimate is based on analysis of aggregate POU loads on past system peak days, adjusting for expected POU load growth or weather-normalization. This service area forecast is also adjusted for any load reductions approved by CPUC. This currently includes specific load modifying demand response programs and utility owned storage resources, as discussed in Step 5.

For San Diego Gas and Electric Company (SDG&E), a CPUC-jurisdictional reference forecast is not needed because there is no non-jurisdictional load in SDG&E's service territory.

An hourly reference forecast for aggregate direct access (DA) load is also developed using recorded hourly electricity service provider (ESP) loads on system peak days. The shape is normalized to the direct access cap, or to current enrollment levels if significantly below the cap. The DA reference forecast is used to evaluate the sum of ESP forecasts.

B. Step 2: LSE-Specific Adjustments

LSEs are directed to submit their hourly forecast for the day of their non-coincident peak, in each month and in each TAC area in which they serve load. The purpose of LSE-specific adjustments (*i.e.*, plausibility adjustments) is to better align the submitted non-coincident peak and energy forecasts with expected loads, based on staff analysis of LSE-specific data, forecast assumptions, and the IEPR forecast. This process reduces the amount of load allocated through the pro-rata process and better aligns allocated load forecasts with cost causation.

LSE-specific adjustments may include up to 3 elements:

(1) Load modifier adjustments
(2) Adjustments to monthly non-coincident peak and peak-day energy
(3) Hour-specific adjustments

i. Load Modifier Adjustments

Load modifiers in the IEPR forecast include electric vehicles, behind-the-meter (BTM) photovoltaic (PV), BTM storage, energy efficiency, fuel substitution, and data centers. LSEs may, but are not required to, document load modifiers in their submitted forecast on Form 3. CEC staff reviews any submittals on Form 3 of the LSE's submitted forecast for consistency with the IEPR. The forecast instructions include an explanation of allowable load modifiers:

> Load modification must be daily, consistent, predictable and verifiable. Programs that trigger load only during predetermined system conditions [i.e., event-based, load-modifying demand response[8]] and/or are integrated into the CAISO market and therefore eligible for RA valuation[9] should not be included in the demand forecast."[10]

The IEPR-managed demand forecast also does not include any front-of-the-meter resources or exports to the grid, so these are not allowed in RA demand forecasts. If any programs or load modifiers included by LSEs on their submitted forecast do not meet these criteria, they are removed from the forecast. Other forecast assumptions, supporting data, and forecast results are reviewed for reasonableness and overall consistency with the IEPR forecast and may be adjusted. The IEPR forecast currently does not include any form of dynamic pricing, including the current expanded dynamic pricing pilots. As new tariffs are implemented, the CPUC—in coordination with CEC—will determine how their impacts should be handled in the RA/planning frameworks.

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8 D.15-11-042, Conclusion of Law 4: "It is reasonable to conclude that without a valid and substantive methodology, event-based load modifying demand response has no capacity value."

9 D.14-03-026, Conclusion of Law 5: "Load Modifying Resource demand response reshapes or reduces the net load curve [i.e., demand forecast] and Supply Resource demand response is integrated into the CAISO market."

10 Demand Forecast Data Request for 2026 Resource Adequacy, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/instructions-for-ra-2026-demand-forecasts.pdf.

ii. Large Load Adjustments (including data centers)

New or expanded large loads need to be allocated to the appropriate LSE. At or prior to the year-ahead forecast meet and confer process, investor-owned utilities (IOUs) will provide CCAs with information on customers expected to interconnect in the CCA's service area the following year. IOUs will also provide this information in their year-ahead load forecasts submitted to CEC. At or prior to the year-ahead forecast meet and confer process, all LSEs will provide information on new or expanding customers the LSE intends to serve in the forthcoming year. In each LSE's year-ahead forecast, new data center or other large loads will be reported on Form 3, including significant expansion at current customer sites. CEC will compare LSE forecasts against the most recent IOU project data and IEPR forecast and make LSE-specific adjustments, as warranted.

iii. Monthly Peak and Peak Day Energy Evaluation

CEC estimates a non-coincident monthly peak demand and peak-day energy benchmark for each LSE to evaluate the need for LSE-specific adjustments. To calculate benchmarks, synthetic loads reflecting the expected customer base are developed. For IOUs and CCAs, 8,760 recorded loads are adjusted by adding or removing recorded loads of expected load migration. From this synthetic load, staff calculates median peak-to-energy ratios and daily energy use on the top five non-coincident LSE peak days. This may include a weather normalization factor derived from the IEPR demand forecast.

For CCAs, monthly peak benchmarks for summer months (June-Sept.) are based on a weather-normalized peak analysis. Using the last three years of synthetic loads and local temperature data, staff fits a regression to daily peaks and temperatures, with indicator variables for day-type, month, and year. The weather statistic used is a three-day moving average of daily maximum temperatures, consisting of 60% of the current day's maximum temperature, 30% of the maximum the day before, and 10% of the maximum two days previous. Weighting in this manner accounts for heat buildup over a three-day period. The coefficients from the regressions are applied to 30 years of historical temperature data, resulting in an estimate of monthly and annual peaks for each weather year. The median (50th percentile) of the annual peak estimates serves as the 1-2 annual peak estimate. For monthly benchmarks, the 80th percentile of monthly maximums is used. However, percentiles calculated by month will always produce a lower maximum 1-in-2 than the annual 1-in-2. For this reason, for monthly benchmarks, the 80th percentile of monthly maximums is used.

IOU adjustments for peak and energy are not done in the same manner as CCAs and ESPs because of the way they develop their forecast. A peak and energy analysis is not needed because the IOUs adjustments are made at the hourly level to align with the hourly CEC forecast. See Section 4 below for these details.

For ESPs, benchmarks are based on the median peak-to-energy ratio and peak-day energy statistics, applied to the most recent Direct Access Service Report (DASR) sales data. The annual DASR sales may be adjusted for specific information on expected load migration as documented in the LSE's submitted forecast.

The default adjustment for ESPs and CCAs is within 5% of the estimated benchmark (this may be either or both peak and energy adjustments). After applying the benchmarks to calculate a target peak and energy, a curve-fitting formula is applied to fit each CCA and ESP's submitted load shape to the revised noncoincident monthly peak and energy:

$$a = \frac{(Target\ Peak - Target\ MWh\ /24)}{(Form1Peak - Form1\ MWh\ /\ 24)}$$

$$b = \frac{(Target\ MWh\ /\ 24\ * Form1Peak\ - TargetPeak * Form1\ MWh\ /\ 24)}{(Form1Peak - Form1\ MWh\ /\ 24)}$$

$$Transformed\ Hourly\ MW = a * Submitted\ Hourly\ MW + b$$

iv. Hour-Specific Adjustment

The transformed load profiles for CCAs and ESPs from Step 2.iii are compared to the LSE synthetic profiles on recent high load days (typically most recent three years, depending on availability of applicable history), normalized to the adjusted peak and energy from Step 2.iii. Based on this comparison, additional off-peak hour-specific adjustments are calculated. If the Step 2.iii hourly forecast deviates from the benchmark by more than 5% in an hour, a default adjustment of 5% is calculated and flagged for review.

IOUs develop their bundled forecast by first developing the service forecast, then subtracting departed load. The benchmark for IOUs is the staff estimated bundled share of the jurisdiction reference forecast. Staff calculates the bundled share of load from the synthetic data. This share is applied to the service area reference forecast and Hourly adjustments are made for deviations greater than 5% from the benchmark.

C. Step 3: Transmission and Unaccounted-for-Energy (UFE) losses

Losses are applied to the adjusted noncoincident LSE hourly load forecasts. Transmission loss factors were established in prior RA decisions, Decision (D.) 05-10-042 to be 2.5%.[11] With the transition to the hourly SOD framework there was no clearly defined method to apply these transmission losses to hourly forecast (Staff is not aware of any hourly transmission loss factors), therefore, CEC is currently applying them only to the availability assessment hours as defined by CAISO (and adopted by the CPUC). Generally, we would expect energy losses to be lower in off-peak hours than peak hours.

PG&E's service area is also adjusted by 0.5% for UFE.[12] UFE losses are applied to all hours.

D. Step 4: Coincidence Adjustment

The purpose of this step is to adjust LSE forecasts to their expected load at the forecasted time of the CAISO system peak. Since the 2013 RA compliance year, coincidence has been based on analysis of LSE-specific loads.[13] Under the SOD framework, a method for hourly adjustments was needed.

Coincidence within a month can be thought of in two parts: (1) within-day, meaning the extent to which the LSE peaks on the same day as the system but at a different hour, and (2) across-month, which measures the extent to which the LSE's highest load days are systematically on different days than system peak days. The forecasts submitted by LSEs account for within-day coincidence, but not across-month.

The pre-SOD methodology used for coincidence was not hour-specific and captured both within-day and across-month coincidence. Staff used this methodology to calculate the total coincidence for an LSE, then subtracted the within-day amount embedded in the adjusted LSE shape.

First, an estimate of total monthly coincidence is calculated as in the past:

$$Total\ Coincidence\ Factor\ (CF) = \frac{Estimated\ LSE\ load\ during\ high\ system\ load\ hours}{LSE\ monthly\ peak}$$

[11] D.05-10-042 at 42.

[12] *Id*.

[13] D.12-06-025.

$$Total\ Load\ Diversity = 1 - CF = LSE's\ total\ load\ diversity\ within\ the\ month$$

This statistic is calculated for the top 3 and 5 CAISO high loads days. The dates selected may be modified considering hourly profiles are consistent with CEC forecast, system emergency conditions, or large amount of demand response resources called. The dates and times used are posted on the RA compliance page each year. The default total coincidence factor is the median CF during top 3 system peak days in each month. From this a net hourly coincidence factor is derived:

$$Within\ day\ Load\ Diversity = 1 - \frac{LSEs\ Adjusted\ Forecast\ at\ System\ Peak\ Hour}{Maximum\ of\ Adjusted\ SOD\ Forecast}$$

$$Residual\ Load\ Diversity = Total\ Load\ Diversity - Within\ day\ Load\ Diversity$$

$$Hourly\ Coincidence\ Factor = Minimum\ (1, 1 + Total\ CF - Embedded\ CF\ in\ Adjusted\ LSE\ Forecast)$$

$$Net\ Hourly\ Coincidence\ Factor = Minimum\ (1, 1 - Residual\ Load\ Diversity)$$

The net hourly CF is applied to the adjusted forecast as of Step 4. It represents remaining across-month diversity. LSEs that peak earlier in the day than system, but typically on the same day may therefore have an hourly CF = 1. If Residual Load Diversity is negative, that implies the submitted or adjusted forecast overestimates the LSEs diversity from system, for example overestimating the drop in load from hours 12 to 18 and further adjustments in Step 2 are needed.

E. **Step 5: Load Credit Adjustment**

Load credits are specific adjustments directed by Commission decisions and are subtracted from the LSE's adjusted forecast. There are currently three types of adjustments.

- Incremental Public Goods Charge program impacts derived from IEPR forecast. They are allocated based on load ratio shares, net of impacts already reflected in the LSE's submitted forecast.
- Credit for certain SCE utility-owned storage. These resources were approved by the Commission for load modifying credit until they achieve deliverability status. LSEs receive a positive credit during discharge in non-summer months; credit is negative in off-peak hours to account for charging. Hourly charge and

discharge profiles were provided by SCE. This is only applicable in non-summer months and is allocated only to LSEs in the SCE TAC area.

- Specific load modifying demand response programs approved by the Commission. This currently includes IOU Critical Peak Pricing programs. Values are provided by CPUC staff.

F. Step 6: LSE-Type Pro Rata Adjustment

After initial runs of the above steps, large deviations may remain between the adjusted forecasts and the CEC reference forecast, most notably (but not only) during solar production hours. Different assumptions about weather-sensitive load and BTM PV production, especially in non-summer months have appeared to be a major driver of these differences. Applying these large adjustments (both positive and negative) to ESPs, who have higher load factors, less BTM PV, and less weather-sensitive load, would produce load shapes at odds with their historical patterns. ESPs would frequently be given an atypical shape, for example with early morning peaks, and total direct access forecasts may exceed the cap on DA load.

Therefore, staff applies an intermediate pro-rata adjustment step by LSE type, with IOUs and CCAs in one group, and ESPs in the other. The IOU plus CCA load reference total is calculated as the service area forecast minus the DA total reference forecast from Step 1. A pro-rata adjustment based on load ratio shares of the forecasts as adjusted through Step 5 is applied to each LSE so that the sum of each group is within 5% of their reference total. This adjustment is made hourly and by TAC area.

G. **Step 7: Final Pro Rata Adjustment**

The final step is to apply a pro rata adjustment to within 1% of service area reference forecast. The adjusted LSE forecasts are reviewed against the submitted forecast and synthetic coincident peak loads to evaluate the reasonableness of the combined adjustments and make revisions as needed. A check on the sum of direct access relative to DA cap is also calculated to evaluate the combined adjustments to ESPs.

(END OF APPENDIX A)