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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes.	Rulemaking 20-05-003

ADMINISTRATIVE LAW JUDGE'S RULING FINALIZING LOAD FORECASTS AND GREENHOUSE GAS EMISSIONS BENCHMARKS FOR 2022 INTEGRATED RESOURCE PLAN FILINGS

Summary

This ruling finalizes the load forecasts and greenhouse gas (GHG) benchmarks for use by load-serving entities (LSEs) in the development and filing of their individual integrated resource plans (IRPs) due on November 1, 2022.

Parties should keep in mind that this ruling directs the starting assumptions and the manner in which the LSEs must bring forward their information and propose their portfolios. In the course of aggregating the individual IRP filings and analyzing the resulting statewide portfolio, the Commission may make different or additional policy choices involving many of the elements of this ruling, prior to adopting the next Preferred System Plan (PSP) and/or requiring additional procurement.

1. Background

On April 20, 2022, an Administrative Law Judge's ruling (ALJ ruling) was issued allowing LSEs to submit information to update their load forecasts, as well as to seek comment on the appropriate GHG targets for the 2035 planning year, which will be included in the next round of individual IRP filings.

Forty six sets of opening comments, including updated load forecast information from LSEs, were filed in response to the April 20, 2022 ALJ ruling, from the following parties: American Clean Power – California (ACP-CA); Alliance for Retail Energy Markets (AReM); Bear Valley Electric Service (BVES); Calpine PowerAmerica; Calpine Energy Solutions; City and County of San Francisco (CCSF); Clean Energy Alliance (CEA); Center for Energy Efficiency and Renewable Technologies (CEERT); Central Coast Community Energy (3CE); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Energy Storage Alliance (CESA); Commercial Energy; Clean Power Authority; Desert Community Energy; Direct Energy; East Bay Community Energy (EBCE); Environmental Defense Fund (EDF); Gexa Energy California; Green Power Institute (GPI); Golden State Power Collaborative; Joint CalChoice Community Choice Aggregators (CCAs); King City Community Power; Liberty Utilities; Marin Clean Energy (MCE); Orange County Power Authority; PacifiCorp; City of Palmdale (Palmdale); Peninsula Clean Energy Authority (PCEA); Protect Our Communities Foundation (PCF); Pacific Gas and Electric Company (PG&E); Pioneer Community Energy; Pilot Power Group; Redwood Coast Energy Authority; Santa Barbara Clean Energy; Southern California Edison Company (SCE); Sonoma Clean Power (Sonoma); San Diego Community Power; San Diego Gas & Electric Company; Solar Energy Industries Association (SEIA); Shell Energy North America; San Jose Clean Energy (SJCE); Silicon Valley Clean Energy (SVCE); University of California Office of the President; and Valley Clean Energy Alliance (VCEA).

Eight sets of reply comments were filed by the following parties: Calpine Corporation; CEERT; CEJA and Sierra Club, jointly; Independent Energy Producers Association (IEP); PG&E; Public Advocates Office (Cal Advocates); SCE; and SEIA.

2. Statewide Load Forecast

The ALJ ruling proposed to use the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) mid case as the energy forecast, consistent with the interagency "single forecast set" agreement with the CEC and the California Independent System Operator (CAISO).

2.1. Parties' Comments

ACP-CA commented that this IRP cycle should account for California's aggressive electrification goals. PG&E recommended having the LSEs plan for the recently-adopted CEC high electrification load forecast.

GPI recommended using the most up-to-date mid-baseline IEPR forecast. SCE noted that there is not enough time to take into account the high electrification case, but pointed out that their own internal forecasts expect higher electrification load and therefore recommended that this assumption should be adjusted in future cycles.

2.2. Discussion

Unless and until there is a different interagency agreement, LSEs are instructed to use the 2021 IEPR mid case, which is consistent with the "single forecast set" agreement between the Commission, CEC, and CAISO. However, to reflect the likelihood of higher load, the 2022 Narrative Template that the LSEs will file as part of the individual IRPs includes a detailed discussion of the electrification planning requirement.

In addition, similar to the last PSP adopted by the Commission in Decision (D.) 22-02-004, when evaluating the aggregated IRPs of the LSEs, the Commission may consider in the development of the next PSP whether a higher electrification load forecast should be used as the basis for the updated statewide portfolio of resources and any associated procurement.

3. Individual LSE Load Forecasts

The ALJ ruling invited LSEs to update their load forecasts, if necessary, from the CEC's IEPR individual forecasts. Twenty LSEs submitted updated energy forecasts compared to the IEPR figures and/or provided peak demand or behind-the-meter photovoltaic (BTM PV) information.

3.1. Parties' Comments

PG&E reacted to the load forecast updates of the CCAs in its service area by requesting an update to its load forecast.

SEIA stated that it does not believe that either PG&E or SCE has justified their alternative BTM PV load forecasts as reasonable. CESA requested that the Commission explicitly allow LSEs to update their BTM storage deployments. Cal Advocates, in its reply comments, argued that the 2021 IEPR forecast accurately reflects the current installed capacity of BTM storage, and the Commission should continue to rely on the CEC's IEPR forecasts for BTM storage.

3.2. Discussion

As with most things related to demand forecasting in the state, the Commission is relying on the CEC to finalize the individual load forecasts for the LSEs, taking into account the CCA updates, particularly in the PG&E service area.

CEC and Commission staff evaluated the submitted forecasts given historical load data, load migration activity, and reasonableness of forecast assumptions compared to the IEPR forecast, to determine whether LSE-specific forecast adjustments were needed.

The differences between the LSE-submitted forecasts and IEPR Form 1.1c largely fell into two categories: 1) near-term differences to reflect recent usage levels, load migration, or service area expansions; and 2) differences in longer-term load growth assumptions, in particular because of impacts from building and transportation electrification and other load modifiers.

Staff incorporated the updated near-term load forecasts, with corollary adjustments to IOU bundled forecasts. For longer-term growth rates, staff evaluated the base forecast and load modifier assumptions and compared them to IEPR forecast assumptions. Then staff either applied the IEPR growth rate to the LSE's near-term forecast or adjusted the LSE's load modifier forecast. The second approach was taken when the base forecast was reasonableness, but the load modifier growth rate deviated significantly from the IEPR. In particular, some LSEs were forecasting significantly more load growth from electric vehicle charging and building electrification than is currently assumed in the IEPR. Since the aggregate of the service area forecasts must remain unchanged from the IEPR, this was necessary to avoid in appropriate reductions to other LSEs' forecasts.

For electric service providers (ESPs), staff estimated each LSE's expected share of 2023 energy in each transmission area using submitted IRP and resource adequacy forecasts, 2021 recorded loads, and direct access service request data. The 2023 energy shares were then applied to the annual direct access cap to produce forecasts for each ESP that, in aggregate, will be consistent with the cap on direct access enrollment.

Peak forecasts are being developed using the IRP sales forecasts determined as described above and the 2023 resource adequacy forecasts. The annual peak of the IEPR forecast continues to occur in September, to IRP peak forecasts are being developed starting with the resource adequacy forecasts for September 2023. After determining resource adequacy forecasts for 2023 following Commission rules and CEC procedures, staff will construct peak forecast for 2024 through 2035 by applying the ratio of each LSE's adjusted coincident peak and annual energy forecasts to the energy forecast determined in this proceeding.

However, resource adequacy forecasts will include a load forecast credit (reduction) for utility-owned storage procurement as authorized in D.21-12-015 (for non-summer months in 2023, and all months in 2024 and beyond). In IRP, this credit will be accounted for on the supply side in LSE filing templates, so no credit will be included in the IRP peak demand forecasts.

For individual IRP filing purposes, the IEPR will also be the source of BTM storage information, as recommended by Cal Advocates. For BTM PV, Commission staff are working on finalizing the assumptions and those will also be posted on our website, taking into account as much updated information as possible. The BTM PV forecasts will be assigned to LSEs consistent with IEPR forecasts. Since many LSEs did not provide BTM PV information in their data submissions, the information will be assigned to LSEs based primarily on the LSE's pro-rata share of load.

The updates from CEC and Commission staff are included in the final load forecasts that are posted on the Commission's website at the following link:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

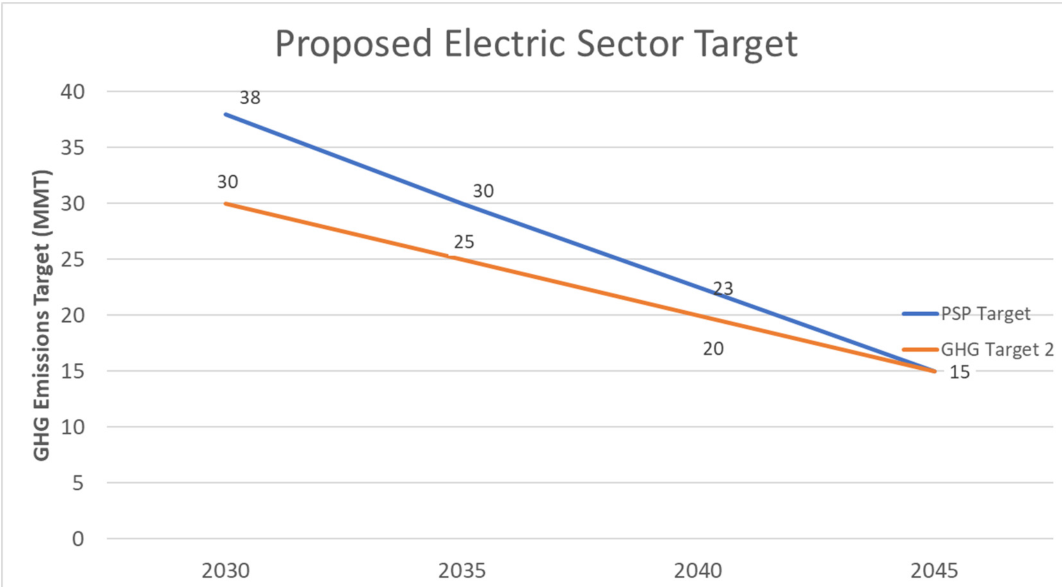
4. Statewide Electric Sector GHG Targets

As stated in D.22-02-004 adopting the most recent PSP, the next round of IRP filings should be planning for 2035 as the target year. The PSP decision also adopted a GHG planning target for 2030 of 38 million metric tons (MMT) of GHG emissions in aggregate for the electricity sector. In addition, LSEs are required to include in their individual IRPs a plan for achieving a 30 MMT GHG target in 2030.

In order to continue meaningful progress toward an ultimate zero-carbon goal for the sector in 2045, as included in Senate Bill (SB) 100 (Stats. 2018, Ch. 312), LSEs will need GHG targets to plan for in 2035, which will be the terminal planning year for the next set of IRPs.

To establish these planning targets for 2035, the ALJ ruling proposed to use a straightline projection of GHG targets between 2030 and 2045, as depicted in Figure 1 below. The straightline projection connects the 2030 targets to a 2045 target of 15 MMT, which is the 2045 GHG target used in the modeling for the PSP decision.

Figure 1. Proposed 2035 Electric Sector GHG Targets



The result of this analysis leads to a GHG target for the electric sector of 30 MMT in 2035 corresponding to the adopted PSP, and 25 MMT GHG target in 2035 for the more stringent planning target. The ALJ ruling proposed to use these targets as the basis for the individual GHG benchmarks to be assigned to individual LSEs for use in their IRP filings due November 1, 2022.

4.1. Parties' Comments

On the topic of the appropriate 2045 GHG target to use as the end point, several parties commented. Calpine Corporation argued that the target should be consistent with the upcoming Scoping Plan update from the California Air Resources Board (CARB). CEJA and Sierra Club recommended using the most recently approved Scoping Plan Update from CARB, which is from 2017.

Several parties supported using zero (0) MMT as the 2045 target, including CEJA/Sierra Club, EDF, PCF, SEIA, and CEERT. SCE opposed using a 0 MMT target, arguing that it represents an incorrect interpretation of SB 100 requirements.

On the 2035 GHG target, several parties supported a lower target. CEERT supported 25 MMT as the lower GHG target, but also recommended adding a 15 MMT target. EBCE and PCF recommending focusing on the 25 MMT target by 2035. PCEA supported the ALJ ruling-recommended targets, but also suggested asking the LSEs to plan to go lower.

Several other parties supported or did not object to the recommended GHG targets in the ALJ ruling, including GPI, IEP, SCE, and Sonoma. Cal Advocates requested a third GHG target, but this suggestion was not supported by PG&E in reply comments.

Several parties also commented on the proposal for a linear interpolation between 2030 targets and 2045 targets. Calpine Corporation, EBCE, EDF, and SEIA supported the approach, with EDF suggesting that the interim targets should be treated as caps. CESA recommended consideration of a more rigorous method for interpolation in the future. PCF recommended using a curved line instead of a linear approach, in order to frontload the GHG reductions and renewable energy procurement.

4.2. Discussion

This ruling adopts the proposals in the previous ALJ ruling as the planning targets for 2035, namely 30 MMT and 25 MMT. These targets are consistent with the Core Scenario in the SB 100 Joint Agency Report with the CEC and CARB.[1] That report's Core Scenario resulted in electric sector GHG emissions of 24 MMT in 2045. The study scenario with expanded load coverage beyond retail sales resulted in emissions decreasing to 12 MMT. The Proposed Scenario in the draft version of the upcoming CARB Scoping Plan Update results

[1] Available at the following link: https://www.energy.ca.gov/sb100.

in 2045 electric sector emissions of 30 MMT. Therefore, the ALJ ruling targets are similar to or lower than both SB 100 and CARB Scoping Plan assumptions for the electric sector emissions in 2045.

It is also worth noting that both the SB 100 Joint Agency Report and the CARB Scoping Plan analyses assume much higher load forecasts than the IEPR mid forecasts being used in this cycle of IRP. A lower GHG target now can help drive procurement that may be needed eventually to meet higher electrification load, while still meeting the same GHG target.

The 2035 30 MMT and 25 MMT targets are in addition to the requirements in D.22-02-004, which require the LSEs to meet their proportional share of the 2030 target of 38 MMT, and plan for a 2030 target of 30 MMT.

5. Individual GHG Benchmarks

The draft GHG benchmarks for each LSE were included in the ALJ ruling, based on the previous load forecasts, for both the 30 MMT target and 25 MMT target for the electric sector in 2035.

The ALJ ruling also noted that 4.4 MMT of behind-the-meter combined heat and power (BTM CHP) GHG emissions were netted out at the system level when calculating these benchmarks. While individual LSEs are not required to plan to reduce BTM CHP emissions, these emissions nevertheless count towards the electric sector emissions total. Commission staff plans to account for BTM CHP emissions when calculating electric sector emissions of the aggregated LSE portfolios during the development of the next PSP. Thus, LSE GHG benchmarks had BTM CHP emissions netted out.

5.1. Parties' Comments

Numerous LSEs included technical or typographical corrections to their own individual benchmarks in their comments. SVCE recommended that the

Commission provide parties with a breakdown of the methodologies used to convert the IEPR load data into GHG benchmarks for the IRP assignments.

On BTM CHP, Direct Energy and AReM recommended that the LSEs should be assigned a commensurate load reduction from the usage of customer-sited BTM CHP and the Commission should consider a reduction in BTM CHP emissions for purposes of calculating the sectoral emissions. PG&E also commented that it is not reasonable to assume that the customers that currently rely on BTM CHP will not take actions to reduce their use of emitting resources, including CHP.

Finally, numerous parties requested that the LSEs be allowed to plan for achieving emissions levels below the benchmarks, including CEERT, CEJA/Sierra Club, PCEA, and SJCE.

5.2. Discussion

The technical and typographical corrections have been made to individual LSE benchmarks and are included in the final spreadsheet available at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

Changes are included for the benchmarks of 3CE, PCEA, SJCE, Palmdale, and CEA. Additional changes flow from the changes to the load forecasts discussed in Section 3 above.

In response to the request for more detail about how the GHG benchmarks are calculated, Commission staff have posted the complete spreadsheet with assumptions and calculations, so parties can understand the calculations more fully.

On the issues related to BTM CHP, Commission staff relied on the 2021 IEPR BTM CHP projections, which do show a decrease in BTM CHP emissions through 2035. The IEPR forecasts generation from BTM CHP, which was then translated into emissions using the heat rate in the RESOLVE model and a front-of-the-meter natural gas generator emissions factor. Emissions were then allocated to LSEs based on their share of CAISO load, net of pumping agency load, using IEPR Form 1.5a.

This ruling also notes that each LSE will have four benchmarks and must show how the LSE intends to reach each of the benchmarks. The four benchmarks are as follows:

- For 2030: Proportional share of 38 MMT
- For 2035: Proportional share of 30 MMT
- For 2030: Proportional share of 30 MMT
- For 2035: Proportional share of 25 MMT

In response to parties that argued that LSEs should be allowed to go below the assigned benchmarks, this ruling agrees, with the following direction. If the LSE intends to go below its proportional share of both the 2030 30 MMT benchmark and the 2035 25 MMT benchmark, then that LSE will only be required to submit one preferred portfolio as part of its individual IRP filing. However, LSEs submitting one preferred portfolio will still be required to submit that portfolio in each of the two sets of Resource Data Templates (RDTs) and Clean System Power (CSP) calculators required for each 2035 GHG target.

Otherwise, each LSE must show two conforming portfolios that meet its proportional share of all four benchmarks.

6. Filing Date

D.22-02-004 set the individual LSE IRP filing date as November 1, 2022.

6.1. Parties' Comments

CCSF and MCE, in their comment in response to the ALJ ruling, requested at least fifteen additional days, to November 16, 2022, to account for the anticipated issuance of peak demand forecasts by July 1, 2022.

6.2. Discussion

This ruling does not grant a delay in the November 1, 2022 filing deadline for the individual IRPs. LSEs should be generally aware of their own peak demand needs. Having the CEC and Commission staff finalize the exact peak demand forecast should not result in the need for a day-for-day extension several months in advance of the filing deadline. LSEs can plan now for their own peak demand needs based on their own knowledge of their customer demand, without needing to wait for the final accounting from Commission staff.

In addition, numerous aspects of the templates for filing the individual IRPs have been simplified, which should assist in faster preparation of the materials by LSEs.

Finally, any later filing deadline could jeopardize the Commission's ability to adopt an updated PSP by the end of 2023.

7. Summary of Filing Requirements

As in the last set of individual IRP filings, each LSE will be required to submit filled out versions of the following materials:

- The Narrative Template
- The Clean System Power Calculator
- The Resource Data Template

Stakeholders should note that the Narrative Template includes further discussion of requirements to provide information about treatment of disadvantaged communities. In particular, the CalEnviroScreen tool used to identify disadvantaged communities has been updated and LSEs should use the most recent version of the tool.

Stakeholders should also note that the RDT includes reliability standards that LSEs are required to meet. The standards comprise a planning reserve margin as well as resource counting rules, including effective load carrying capabilities (ELCCs). In combination, these standards enable LSEs to show that their portfolios contribute their share of system reliability.

The final versions of the materials required as part of the individual IRPs and filing requirement instructions will be posted on the Commission's website at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

Commission Staff will also provide the confidential peak load forecasts and BTM PV forecasts to the individual LSEs by no later than July 1, 2022. Also around the same timeframe, Commission staff will post the final versions of the CSP Calculators and RDT. The final RDT will also include the ELCC referred to above.

After all of these final materials are available, Commission staff intend to host "office hours" to answer questions and facilitate LSE development of the required elements of the individual IRPs. Commission staff will also hold a webinar to present the most recent reliability modeling results (including planning reserve margin and ELCC results), to promote stakeholder understanding of the modeling, methodology, and results. There will be opportunities for parties to comment on this modeling work in this proceeding later in 2022.

IT IS RULED that:

1. Each load-serving entity shall submit, by no later than November 1, 2022, the following materials as part of its individual integrated resource plan for 2022, based on the templates posted on the Commission's web site at the following link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

(a) Narrative Template

(b) Clean System Power Calculator

(c) Resource Data Template

2. Each load-serving entity (LSE) shall submit, as part of the requirements in Ruling Paragraph 1, a portfolio that meets its proportional share of a target of 38 million metric ton (MMT) of greenhouse gas (GHG) emissions in 2030 and a target of 35 MMT in 2035, and a second portfolio that meets a GHG target of 30 MMT or less in 2030 and 25 MMT or less in 2035. If the LSE has a preferred portfolio that meets its proportional share of a GHG target of 30 MMT or less in 2030 and 25 MMT or less in 2035, then that LSE may submit only that one preferred portfolio and does not need to submit a portfolio that meets the higher GHG targets. However, an LSE submitting only one portfolio must submit that portfolio in each of the two Resource Data Templates and Clean System Power calculators.

Dated June 15, 2022, at San Francisco, California.

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