ALJ/SW9/jnf 4/24/2024

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R2207005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005

ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B WORKING GROUP 1 PROPOSALS AND ISSUE 5

This ruling directs Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (together, the Large Utilities) and invites other parties to comment on each of the questions in Attachment A to this ruling. The Large Utilities shall, and other parties may, file opening comments by May 22, 2024, and reply comments by June 12, 2024.

On November 2, 2022, the assigned Commissioner issued a scoping memo and ruling (scoping memo) to establish the issues in scope and initial schedule for this proceeding. The scoping memo provided that Track B of this proceeding would streamline and expedite the adoption of demand flexibility rates for large investor-owned electric utilities. The scoping ruling established two working groups: Working Group 1, which would propose how to address Track B Issue 3 (what guidance the Commission should adopt for demand flexibility design), and Working Group 2, which would propose how to address Track B Issue 4 (how to ensure access to dynamic electricity prices, including systems and processes for access to prices and responding to price signals). Track B also included Issue 5 (how the Commission should support the implementation of the amendments to the California Energy Commission's Load Management Standards).

On October 11, 2023, Southern California Edison Company filed a report with Track B Working Group 1 and Working Group 2 proposals (Working Group Report) on behalf of both working groups. Parties filed opening comments on the Working Group Report by November 13, 2023, and replies by December 22, 2023.

This Track B ruling directs the Large Utilities and invites other parties to comment on each of the questions in Attachment A, which relates to the Working Group 1 proposals and Issue 5.

IT IS SO RULED.

Dated April 24, 2024, at San Francisco, California.

/s/ STEPHANIE WANG
Stephanie Wang
Administrative Law Judge

ATTACHMENT A
(Questions for Party Comments)

Attachment A

Ruling Questions on Track B Working Group 1 Proposals and Issue 5

This document includes questions regarding (a) proposals in Track B Working Group Report relating to Issue 3 in the scoping memo (Guidance for demand flexibility rate applications – Working Group 1), and (b) Track B, Issue 5 (Compliance with CEC Load Management Standards).

The assigned Administrative Law Judge anticipates mailing a Proposed Decision addressing the issues in Working Group (WG) 1 and Issue 5 in Q3 or Q4 of this year. Working Group 2 proposals issues will be addressed separately in this proceeding.

1 Guidance regarding Rate Design for Marginal Generation Capacity Costs

1.1 Annual Update of Marginal Generation Capacity Costs

The Track B Working Group Report submitted by SCE on October 11, 2023, included 3 proposals submitted by ED staff, Joint IOUs, and Microgrids Resources Council for guidance that the CPUC should adopt for IOU applications for CEC Load Management Standards (LMS)-compliant marginal cost-based rates. Parties identified the requirement that CEC LMS compliant cost-based rates should include an hourly price component that "shall reflect the variations in the probability and value of system reliability of each [capacity] component (generation, transmission, and distribution."[1]

Several proposals in the Track B Working Group Report recommended that the generation capacity component for a dynamic marginal cost-based rate should be designed to annually recover a utility company's Marginal Generation Capacity Cost (MGCC), as approved by the CPUC in a utility's most recent General Rate Case (GRC) Phase 2. However, the GRC approved MGCC may not be an up-to-date representation of the actual costs incurred by the utility company's procurement of sufficient generation capacity to meet its system reliability needs during the attrition years of a GRC II cycle.[2]

On April 19, 2024, PG&E submitted Advice Letter (AL) 7243-E, which proposed to update the marginal cost signals for all PG&E Real-Time Pricing (RTP) pilots and rates. In that AL, PG&E notes that illustrative rates in D. 21-11-016 were designed using marginal costs that corresponded to the revenue requirements (RRQs) of more than 4 years ago. To date,

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[1] Cal. Code Reg. Title 20, Section 1623.1(b)(1)

[2] D.21-11-016 at 49-53

all proposals for dynamic rates have held these same marginal costs constant, even though the RRQ for generation and distribution have grown substantially, 124% and 123% respectively (adjusted for sales changes). PG&E notes that its marginal costs also have increased significantly since 2020. System Resource Adequacy values, the "short-run version" of the MGCC, have increased from $62/kW-year in 2020 to $183/kW-year today based on the 2020 and 2023 Market Price Benchmarks,[3] while the capital costs of grid-scale batteries also increased significantly, as reflected in Inputs and Assumptions for the respective IRP Preferred System Plans. PG&E asserts that maintaining the 2020 marginal costs, which are significantly out of date, will not send a strong enough price signal to customers on the pilots. Increasing the marginal costs will not affect average rates but will give customers a larger opportunity to reduce their bills when they shift load.[4]

In AL 7243-E, PG&E proposes to update its capacity marginal costs, for the purposes of setting the coefficients for dynamic prices for its RTP pilot rates only, in proportion to its RRQ changes since May 1, 2020, adjusted for sales changes. Specifically, PG&E proposes that the MGCC (for its RTP pilot rates) will be:

$$MGCC_{RTP-pilots} = MGCC_{2020-GRC} \times \frac{Current\ Bundled\ Average\ Generation\ Rate\ (\$/kWh)}{May\ 1, 2020\ Bundled\ Average\ Generation\ Rate\ (\$/kWh)}$$

In AL 7243-E, PG&E proposes that this scaling relationship continue to adjust its RTP pilot dynamic rates until PG&E updates its marginal costs in its 2023 GRC Phase II Proposal in September 2024. At that time, PG&E proposes to use its updated marginal generation and distribution costs and will also propose in that filing a longer-term solution for updating marginal costs over time.

1.2 MGCC Questions for Party Comments:

1. Should the CPUC require annual updates to the MGCC for hourly marginal cost-based rates for all large IOUs? Why or why not?
    a. If so, what methodology should the CPUC authorize for the annual updates? For example, should the same approach as proposed by PG&E in AL 7243-E be used?

2. How would an annual adjustment of the MGCC for hourly marginal cost-based rates align with the CPUC's updated Rate Design Principles and new Demand Flexibility Design Principles? For example, would an annual update encourage customer behaviors that improve electric system reliability in an economically efficient manner?

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[3] See Energy Division Calculation of Market Price for the Power Charge Indifference Adjustment Forecast and True up, October 2, 2023. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-mpb-2023-2024-final.pdf.

[4] PG&E AL 7243-E at 2-3

3. If the Commission adopts annual updates, what process should facilitate an annual adjustment of the MGCC for hourly marginal cost-based rates? For example, should the IOUs be required to file an Advice Letter to update the MGCC for hourly marginal cost-based rates? Should this process be incorporated into the IOUs' annual consolidated filings or another process?

2 Guidance regarding Rate Design for Marginal Distribution Capacity Costs

2.1 Annual Update of Marginal Distribution Capacity Costs

For Marginal Distribution Capacity Costs (MDCCs) for hourly marginal cost-based rates, the Joint IOUs recommended only including the primary or time-dependent distribution costs, asserting that the time-dependent portion of marginal distribution costs (Primary-MDCC or PDCC) are much smaller in magnitude compared to the time-dependent portion of generation costs. For example, based on its 2020 GRC Phase 2 decision marginal costs, PG&E claims that the average rate for its marginal generation costs (7.9 cents/kWh) is 6.5 times greater than its average rate for its marginal distribution costs (1.1 cents/kWh).[5]

As PG&E notes in AL 7243-E, both its distribution and generation revenue requirements (RRQs) have grown significantly since PG&E's 2020 GRC Phase 2 application was filed. PG&E further notes that its costs to upgrade its distribution system have also increased, with increased wildfire hardening procedures and vegetation management. However, both its MDCCs correspond to the distribution RRQ of more than 4 years ago.[6] PG&E asserts that maintaining the 2020 marginal costs, which are significantly out of date, will not send a strong enough price signal to customers on the pilots. Increasing the marginal costs will not affect average rates, but will give customers a larger opportunity to reduce their bills when they shift load.

In AL 7243-E, PG&E proposes to update its capacity marginal costs, for the purposes of setting the coefficients for dynamic prices for its RTP pilot rates only, in proportion to its RRQ changes since May 1, 2020, adjusted for sales changes.[7] Specifically, PG&E proposes that the Primary-MDCC (for its RTP pilot rates) will be:

$$PDCC_{RTP-pilots} = PDCC_{2020-GRC} \times \frac{Current\ Bundled\ Average\ Distribution\ Rate\ (\$/kWh)}{May\ 1, 2020\ Bundled\ Average\ Distribution\ Rate\ (\$/kWh)}$$

In AL 7243-E, PG&E proposes that this scaling relationship continue to adjust its RTP pilot dynamic rates until PG&E updates its marginal costs in its 2023 GRC Phase II Proposal in September 2024. At that time, PG&E proposes to use its updated marginal generation

[5] See R.22-07-005 Track B Working Group Report filed by SCE on October 11, 2023 at 78.
[6] PG&E AL 7243-E at 2-3
[7] PG&E AL 7243-E at 3

and distribution costs and will also propose in that filing a longer-term solution for updating marginal costs over time.

2.2 Scaling of Marginal Distribution Capacity Costs for Marginal Cost-Based Hourly Rates

In its comments on the Joint IOUs Working Group 1 proposal, CLECA suggested using multipliers (either EPMC or another similar scalar) to adjust marginal costs, including those for distribution capacity. CLECA referenced a precedent set by the CPUC, which, in D.17-01-013 at page 51, instructed PG&E to apply full EPMC scaling to all marginal cost components in order to create more cost-based rates.[8] See table below for historical Revenue Requirements for both Marginal and Total Distribution Revenues.

IOU	Year	MDCC Revenue Requirement ($/year)	Total Distribution Revenue Requirement ($/year)	% of MDCC Rev Req to total Dist. Rev Req
PG&E	2014	$931,492,000	$3,401,646,000	27%
PG&E	2017	$1,085,509,000	$4,070,221,000	27%
PG&E	2020	$1,997,179,000	$4,929,770,000	41%
SCE	2015	$2,493,798,000	$4,511,639,000	55%
SCE	2018	$2,520,083,000	$4,317,686,000	58%
SCE	2021	$2,961,275,000	$6,922,226,000	43%
SDG&E	2016	$473,427,000	$1,373,145,000	34%
SDG&E	2020	$472,898,000	$1,678,592,000	28%
SDG&E	2024	$657,968,000	$1,924,872,000	34%

2.3 Geographic Granularity of Distribution Prices

Both ED staff and Joint IOUs proposed that the annual average of the dynamic distribution rate should be the same across all circuits to be equitable. That is, the dynamic distribution rate should not be higher on average for relatively more congested circuit segments. However, the Joint IOUs also proposed that the initial rate applications should not be required to have a dynamic distribution price more geographically granular than a system-wide price.[9] The Joint IOUs proposed that more complex dynamic distribution rate designs should be tested on constrained circuits prior to implementing in a full-scale RTP rate. In contrast, ED staff had recommended that distribution prices be at least as geographically granular as a substation. Accordingly, distribution prices downstream of a substation should be a function of the net load at that substation. Moreover, another option for geographic granularity of distribution

[8] See Track B Working Group Report filed by SCE on Oct 11, 2024 at 85.
[9] See Track B Working Group Report filed by SCE on Oct 11, 2024 at 6.

pricing is being implemented in PG&E's upcoming VGI pilot, where the hourly distribution price will be based on grouping circuits of similar load profiles into clusters.[10]

2.4 MDCC Questions for Party Comments:

4. Should the CPUC require annual updates to the revenue recovery target for the MDCC for hourly marginal cost-based rates in order to improve the accuracy and effectiveness of the distribution price signal and reflect cost-causation for all IOUs?
    a. If the CPUC authorizes annual updates, what methodology should the CPUC authorize for the annual updates? For example, should the CPUC require that the same approach as proposed by PG&E in AL 7243-E be used?
    b. Would an annual adjustment of the revenue recovery target for the MDCC be aligned with the CPUC's updated Rate Design Principles and new Demand Flexibility Design Principles?

5. If the Commission requires annual updates to the MDCC for hourly marginal cost-based rates, what process should facilitate the annual updates? For example, should the IOUs be required to file an annual Advice Letter? Should this process be incorporated into the IOUs' annual consolidated filings or another process?

6. Should the CPUC require using multipliers (either EPMC or another similar scalar) to the MDCC for hourly marginal cost-based rates? Would it be reasonable for this multiplier to apply to both imports and exports?

7. (For the IOUs only) What is the cost, scope and timeline for each IOU to implement a CEC-LMS complaint hourly marginal cost-based with the following geographic granularity for the hourly distribution prices:
    a. An approach similar to what is being implemented in PG&E's upcoming VGI pilot, where the hourly distribution prices will be based on grouping circuits of similar load profiles into clusters.
    b. An approach where the hourly distribution prices are based on the local substation load for all circuits downstream of each substation.

3 Compliance with CEC LMS Deadlines for Marginal Cost Hourly Rates

Per the updated CEC LMS, Title 20, Section 1623 (a)(2), the IOUs are required to submit rate applications to the CPUC for at least one marginal cost-based rate for each customer class by January 2025.

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[10] See Track B Working Group Report filed by SCE on Oct 11, 2024 at 59.

8. When and in what procedural venue does each IOU propose to submit its application for marginal cost-based rates? (Each IOU should provide a separate response to this question.)

4 Study for Low Income Customers

Question 3d of the Phase 1 scoping memo asked parties to consider barriers for low-income communities to participate and benefit from dynamic rates. The proposals included in the Working Group report included some ideas on how to align demand flexibility rate design with the commission's ESJ action plan, and how to target low-income families through IOU's Marketing Education, and Outreach programs. Although parties have made comments on the proposals, there were no specific proposals regarding guidance the CPUC should adopt for demand flexibility design for low-income residential customers.

Questions for party comments:

9. Should the Commission direct the IOUs to conduct a new study or modify a planned study to better understand:
    a. The needs of low-income residential customers with respect to responding to dynamic rates and whether and how residents of disadvantaged communities can benefit from dynamic rates in certain climate zones (e.g. by providing inexpensive tools for automating air conditioning), and
    b. How low-income residential customers would respond to dynamic rates and/or more cost-reflective TOU rates?

10. Will current or upcoming studies conducted on low-income customers or customers in disadvantaged communities (e.g., Community Based Organizations Arrearages Case Management Pilot study authorized in D.24-02-046 in the residential energy disconnections proceeding, Rulemaking 18-07-005) make it unnecessary to direct a new study in this proceeding?

11. If the CPUC decides to direct the IOUs to conduct a new study:
    a. What should be the scope of that study?
    b. Should the Commission direct an IOU to conduct an RFP for an independent consultant to conduct the study? If so, what should be the criteria for selecting the consultant?
    c. How should stakeholders be involved in developing the study?
    d. When should the study be completed?
    e. What process should be used to recover the costs of the study?
    f. Should a budget be authorized for the study, and if so, what budget should be authorized?

5 Implementation of CEC LMS Requirements

This question is regarding the cost recovery that the IOUs are seeking in order to meet CEC LMS requirements including: (a) uploading their rates to the CEC Market Informed Demand Automation Server (MIDAS) rate database, (b) development of the stand rate information access toll to support third party services, (c) inclusion of a Rate Identifier Number in customer bills.

Specifically, party comments on the questions below should focus on implementation costs and cost recovery processes that need to be authorized by the end of 2024 in the upcoming decision on the Working Group 1 proposal. This ruling question does not address costs relating to Working Group 2 proposal.

PG&E, SCE and SDG&E are directed to each respond to the following questions:

12. What implementation costs need to be authorized by the Commission before the end of 2024 in order to comply with the CEC LMS requirements?

13. Please propose the process details regarding the revenue/cost tracking account for these implementation costs (i.e., memorandum account or balancing account). Please also address whether a new or an existing account should be used for these costs.

(END OF ATTACHMENT A)