STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 22-07-005:

This is the proposed decision of Administrative Law Judges Rajan Mutialu and Carolyn Sisto. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 28, 2025 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE

Michelle Cooke
Chief Administrative Law Judge

MLC:avs
Attachment

Decision **PROPOSED DECISION OF ALJ MUTIALU AND ALJ SISTO**
(Mailed 7/25/2025)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION ADOPTING GUIDELINES FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY ON DEMAND FLEXIBILITY RATE DESIGN PROPOSALS

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Summary

This decision adopts guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to design demand flexibility rates and comply with the California Energy Commission's Load Management Standards. Specifically, this decision adopts guidance for how various cost components should be incorporated into demand flexibility rate proposals to provide accurate price signals that promote economically efficient load shifting and support grid reliability. Further, this decision adopts guidance for the design of customer options that promote load shifting in response to electricity pricing while minimizing bill impacts.

For context, the California Energy Commission adopted the Load Management Standards to motivate electric customers to shift electricity demand, or load, from high-demand periods when peaking power plants and other polluting generators tend to be in use, to periods when lower-cost clean electricity is available. The Load Management Standards were designed to incentivize load shifting through customer use of demand flexibility rates that reflect actual grid conditions and are based on marginal costs for the generation and delivery of electricity on a time interval of no more than one hour.

This rulemaking is closed.

1. Procedural Background

On July 22, 2022, the California Public Utilities Commission (Commission) approved an Order Instituting Rulemaking to initiate Rulemaking (R.) 22-07-005 (OIR) to institute policies and rates that promote electric demand flexibility (DF), meaning the ability for customers to change their electric consumption patterns on an hourly, sub-hourly, or real-time basis. The DF OIR envisioned that DF policies, programs, and rates; as informed by studies, pilots, tools, and rate design principles, would be designed to meet the following objectives: (a) enhance the reliability of California's electric system; (b) make electric bills more affordable and equitable; (c) reduce the curtailment of renewable energy and greenhouse gas (GHG) emissions associated with meeting the State's future system load; (d) widespread electrification of buildings and transportation to meet the state's climate goals; (e) reduce long-term system costs through more efficient pricing of electricity; and (f) enable participation in DF by both bundled and unbundled customers. The DF OIR also aimed to better support fair and affordable rates for all Californians and advance the Commission's Environmental and Social Justice (ESJ) Action Plan.[1]

The prehearing conference (PHC) in this rulemaking was held by the assigned Administrative Law Judge (ALJ) on September 16, 2022.

On October 12, 2022, the California Energy Commission (CEC) amended its Load Management Standards, codified in Title 20, California Code of Regulations (CCR), Sections 1621-25; 20 CCR 1623 specifies regulations for Load Management Standard tariffs. Section 1623 (a)(1) explicitly requires that

> total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution) and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated GHG gas emissions, on a time interval of no more than one hour.

[1] Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates, July 22, 2022.

Section 1623 (a)(1) also specifies that marginal cost-based rates shall (1) reflect locational marginal cost pricing as determined by the associated balancing authority, such as the California Independent System Operator (CAISO), the Balancing Authority of Northern California, or other balancing authority and marginal capacity cost computations; and (2) account for variations in the probability and value of system reliability of each component (generation, transmission, and distribution).

Moreover, Section 1623 (a)(2) requires that within twenty-one (21) months of April 1, 2023, PG&E, SCE, and SDG&E shall each apply to their rate-approving body, the Commission for approval of at least one marginal cost-based rate, in accordance with Section 1623(a)(1), for each customer class.

On November 2, 2022, the assigned Commissioner issued a Phase 1 Scoping Memo and Ruling (Scoping Memo).

The Scoping Memo established two tracks in Phase 1 of this proceeding: Track A, to determine how to implement Assembly Bill (AB) 205 (Ting et. al), Stats. 2022, Ch. 61, and Track B, to streamline and facilitate adoption of DF rates for large California investor-owned electric utilities (IOUs), including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).[2] Track B was scoped to revise current rate design principles for all electric rates and develop new principles, guidance, and a common vision and framework for the design of DF rates moving forward.

After this first step, Track B targeted the development of new systems and processes for electricity customers and electric service providers to access and

[2] Assigned Commissioner's Phase 1 Scoping Memo and Ruling, November 2, 2022, at 2-3.

utilize dynamic electricity rates that reflect near real-time electricity prices. This latter step in the Track B process is aimed at evaluating the expansion of current dynamic or DF rate pilots as a near-term solution to support electric system reliability. The Scoping Memo noted that R.22-07-005 Phase 1, Track B would not set requirements for small and multi-jurisdictional electric utilities. Requirements for these utilities would be addressed in Phase 2 of this proceeding.[3]

The Scoping Memo listed Track B issues as follows:[4]

1. How should the Commission update its electric rate design principles to advance current state goals?
2. What principles should the Commission adopt for DF design?
3. What guidance should the Commission adopt for DF design?
    a. How should wholesale market prices be incorporated into DF price signals?
    b. What options should be provided to help customers plan and manage their bills (e.g. customer load shape subscriptions, forward transactions, bill protections)?
    c. How should the timing of customer exports be aligned with our goals to reduce GHG gas emissions, reduce curtailment of renewable energy, and enhance system reliability?
    d. How should DF design consider the barriers and needs of low-income and disadvantaged communities and advance the Commission's ESJ Action Plan goals?
    e. How should DF rates be designed to enable all load serving entities to have the option to participate?

[3] Assigned Commissioner's Phase 1 Scoping Memo and Ruling, November 2, 2022, at 2-3.

[4] Assigned Commissioner's Phase 1 Scoping Memo and Ruling, November 2, 2022, at 4-5.

   f. How should DF rates be designed to comply with California Energy Commission's amendments to the Load Management Standards?

4. How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize to facilitate access to prices and response to price signals?
   a. What systems and processes should the Commission authorize for computation of dynamic prices for bundled and unbundled customers?
   b. What systems and processes should the Commission authorize to enable load serving entities to offer unbundled customers the option to take service on dynamic electricity prices?
   c. What systems and processes should the Commission authorize to enable third-party service providers (e.g., automation service providers, device manufacturers) to offer DF services to customers?
   d. What systems and processes should the Commission authorize to enable customers to optimize and pre-schedule their energy use to provide DF (e.g., forward transactions)?
   e. What are the costs associated with these systems and processes (for access to prices and responding to price signals), and how should these costs be recovered?
   f. How should these systems and processes for access to prices and responding to price signals be managed and overseen (e.g., LSE/utility administration or third-party administration)?
5. How should the Commission support the implementation of the amendments to the Load Management Standards?

6. Should the Commission expand any of the existing dynamic rate pilots as near-term solutions that may benefit system reliability and reduce GHG emissions?

To address Track B, Scoping Items 3 and 4, the Scoping Memo directed the Commission's Energy Division staff (Staff) to create and facilitate two working groups, Working Group 1 and Working Group 2. The Scoping Memo Item 3 directed Working Group 1 to focus on developing guidance for the large IOUs to file DF design applications. As directed in Scoping Item 4, Working Group 2 was directed to design systems and processes for customers and service providers to access electricity prices and respond to price signals. SCE was tasked with drafting a Track B Working Group 1 and Working Group 2 Report (Track B Report).[5]

In November 2022, Staff notified the R.22-07-005 service list that Staff created Working Group 1 and Working Group 2. Further, Staff requested public and party participation in both Working Group 1 and Working Group 2. Working Group 1 meetings were held in early January 2023 to deliberate on the design of DF electric rates. Working Group 1 participants including representatives from investor-owned utilities (IOUs) community choice aggregators (CCAs), consumer advocacy groups, device manufacturers, third-party providers, and other potential stakeholders met on a bi-weekly basis through early August 2023.[6] DF rate design proposals from Staff; PG&E, SCE, and SDG&E (Joint IOUs); and Microgrid Resources Coalition (Microgrid RC) were submitted and discussed at subsequent Working Group 1 meetings. Working Group 1 participants had the opportunity to comment on these

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[5] Assigned Commissioner's Phase 1 Scoping Memo and Ruling, November 2, 2022, at 6-7.

[6] Track B Working Group Report, Appendix 2.

proposals. In Section 3 of the Track B Report, SCE compiled Working Group 1 DF rate design proposals and participant comments.

On April 27, 2023, Decision (D.) 23-04-040 adopted modified versions of electric rate design principles first introduced in D.14-06-029. The updated rate design principles preserved direction for designing just and reasonable rates but added necessary language to facilitate meeting current state goals. D.23-04-040 also adopted DF design principles to guide the development of DF tariffs, systems, processes, and customer experiences of the large IOUs.[7]

The ALJ issued a ruling on September 29, 2023, that modified the procedural schedule to allow the Track B Report to be filed by October 11, 2023, comments to be filed by November 13, 2023, and replies by December 22, 2023.

On October 11, 2023, SCE filed the Track B Report which included party proposals from the Joint IOUs, Microgrid RC, and Staff and comments on these proposals. Staff's Track B Working Group 1 proposed guidance is sourced from their California Flexible Unified Signal for Energy paper and proposal, issued in June 2022, as well as presentations, workbooks, and reports on rate design that were discussed with Working Group Participants.

On November 13, 2023, Leapfrog Power, Inc.; Public Advocates Office at the California Public Utilities Commission (Cal Advocates); and California Manufacturers & Technology Association (CMTA), California Large Energy Consumers Association (CLECA), Energy Producers and Users Coalition (EPUC), and Federal Executives Agencies (FEA), collectively the "Joint Parties,"; the Joint IOUs; California Community Choice Association (CalCCA); Utilities Consumers' Action Network (UCAN); Vehicle-Grid Integration Council (VGIC);

[7] D.23-04-040, Attachment A.

Google LLC; California Energy Storage Alliance (CESA); and Solar Energy Industries Association (SEIA) filed comments on the Track B Report. Nostromo Energy Inc. filed comments on November 30, 2023.

On December 21, 2023, Generac Power Systems, Inc., 350 Bay Area, Sierra Club, and Leapfrog Power Inc., filed reply comments. SEIA, VGIC, Cal Advocates, Weave Grid, Inc., Joint Parties, CalCCA, UCAN, and Joint IOUs filed reply comments on December 22, 2023.

On April 24, 2024, the assigned ALJ issued a ruling (April 24 Ruling) that requested party comment on Track B Working Group 1 Proposals and Scoping Issue 5 related to updating of marginal electric generation capacity costs (MGCC) and marginal electric distribution capacity costs (MDCC).[8]

On May 22, 2024, the Joint IOUs, SEIA, Small Business Utilities Advocates (SBUA), EPUC, CLECA, Cal Advocates, CalCCA, and Sierra Club filed opening comments on the April 24 Ruling. On June 12, 2024, replies were filed by the Joint IOUs, EPUC, SEIA, Microgrid RC, Cal Advocates, the Center for Accessible Technology (CforAT), and the California Community Choice Association.

On June 26, 2024, SCE filed Application (A.) 24-06-014 to seek Commission approval of a large power dynamic pricing rate. In its application, SCE explained that its proposed rate would be a precursor to the marginal cost-based rate design that SCE would submit to the Commission for approval by January 1, 2025, to comply with the CEC Load Management Standards.

On September 30, 2024, PG&E filed its 2025 General Rate Case Phase 2 (GRC Phase 2) A.24-09-014 to seek approval of proposed electric marginal costs, revenue allocation, and rate design.

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[8] ALJ Ruling on Track B Working Group 1 Proposals and Issue 5, April 24, 2024.

On December 20, 2024, SCE filed A.24-12-008 to seek Commission approval of marginal cost-based demand flexibility rates to comply with requirements from the CEC Load Management Standards and D.22-10-022. Concerning the latter, the Commission directed SCE to propose CAISO-Real Time Pricing (RTP) rates in its next GRC Phase 2 application, A.24-03-019, which was filed on March 29, 2024.[9]

This matter was submitted on June 12, 2024, upon the filing of party reply comments on the ALJ Ruling on Working Group 1 Proposals and Issue 5.

2. Issues Before the Commission

The issues before the Commission are the following:[10]

1. What guidance should the Commission adopt for DF design?
2. How should wholesale market prices be incorporated into DF price signals?
3. What options should be provided to help customers plan and manage their bills (*e.g.* customer load shape subscriptions, forward transactions, and/or bill protections)?
4. How should the timing of customer exports be aligned with grid needs to reduce GHG emissions, reduce curtailment of renewable energy, and enhance system reliability?
5. How should DF design consider the barriers and needs of low-income and disadvantaged communities and advance the Commission's ESJ Action Plan goals?
6. How should DF rates be designed to enable all load serving entities to have the option to participate?

[9] D.22-10-022, Ordering Paragraph (OP) 5.

[10] Assigned Commissioner's Phase 1 Scoping Memo and Ruling at 4.

7. How should DF rates be designed to comply with the California Energy Commission's amendments to the Load Management Standards?

This decision provides general guidance for the design of all types of DF rate proposals from PG&E, SCE, and SDG&E (hereafter referred to as DF Rate Proposals); including in DF Rate Proposals, stand-alone applications, and GRC Phase 2 applications that are targeted at compliance with CEC Load Management Standard requirements. This decision does not apply to the Small Multi-Jurisdictional Utilities.

This decision closes R.22-07-005 without resolving the remaining Phase 1 scoping issues of this proceeding, which include (1) Track B, Working Group 2 Issues 4, 5, and 6 that relate to systems and process to enable access to dynamic rates, Commission support on implementing amendments to the CEC LMS, expansion of existing dynamic rate pilots[11] and (2) issues relating to DF rates for large commercial hydrogen generation and industrial heat process producers. The Commission will address these issues in one or more new rulemakings.

Staff will prepare more detailed recommendations that incorporate the concepts and learnings from the Working Group 2 process. The Commission may consider the new Staff recommendations related to Working Group 2 issues in a future proceeding. Staff will also host a workshop in 2025 to identify how large commercial hydrogen generation and industrial heat process producers can utilize and potentially benefit from dynamic rates in the future.[12] After the

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[11] R.22-07-005 Assigned Commissioner's Phase 1 Scoping Memo and Ruling at 4-5.

[12] The workshop will address: (a) whether demand flexibility rates for hydrogen and industrial process heat producing customers should differ from other large commercial customers; (b) what elements of demand flexibility rates designed specifically for specific customer classes will prevent cost shifting to other customer classes, and (c) how could new tariff designs for

workshop, Staff will assess how large commercial hydrogen generation and industrial heat process producers can utilize more dynamic rates. The Commission may consider Staff's hydrogen/industrial heat recommendations in a future proceeding.

This decision is organized as follows: In each of the following sections, we describe underlying concepts about specific DF rate elements. Then, we will provide an overview of Staff, Joint IOU, and Microgrid RC DF proposals to design these rate elements and summarize participant comments on these proposals as detailed in the Track B Report. Additionally, we will describe relevant party comments on the April 24 Ruling questions related to updating, granularity, and scaling of MGCC and MDCC, conducting a low-income study to examine access to and use of DF rates, and implementation of the CEC Load Management Standards. Finally, this decision provides guidance to the Joint IOUs for the design of all DF Rate Proposals.

3. Process for Compliance with California Energy Commission Load Management Standards

Each Large IOU is required to file an application with the Commission that seeks approval for at least one marginal-cost based DF rate for each customer class by January 2025.[13] In response to the April 24 Ruling, the Large IOUs identified when and in what procedural venue they planned to file applications. PG&E has sought Commission approval for marginal cost-based DF Rate Proposals as part of its 2023 GRC Phase 2 application, A.24-09-014. PG&E states

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large commercial customers, including hydrogen and/or industrial heat producers, better align with the electric rate design principles adopted in D.23-04-040.

[13] Per updated CEC LMS requirements, Title 20, Section 1623 (a)(2).

that it will propose a transmission rate design to the Federal Energy Regulatory Commission (FERC) in a single-issue filing around July 2026.[14]

SDG&E states it plans to comply with Ordering Paragraph (OP) 1 of D.23-11-006, which requires SDG&E to submit its application for a dynamic pricing import rate 60 days after the issuance of a Commission decision in this rulemaking.[15]

SCE filed a standalone rate application, A.24-06-014, to seek Commission approval of DF rates for large power customers on June 26, 2024. SCE filed A.24-12-008 to seek Commission approval of marginal cost-based DF rates to comply with requirements from the CEC LMS and D.22-10-022 on December 20, 2024.[16] SCE proposes to conduct a transmission marginal cost study to establish the relationship between fixed and variable cost components within the same rate application. Further, SCE explains that it intends to file a single-issue application with the FERC after obtaining FERC's approval of SCE's transmission rate framework.[17]

We recognize that PG&E and SCE filed their DF Rate Proposals prior to the issuance of this decision. To comply with the CEC Load Management Standards and this guidance decision, it is reasonable to (a) direct SDG&E to file a consolidated application for DF Rate Proposals that complies with the guidance in this decision for all customer classes within 90 days of the issuance of this decision. (b) direct PG&E and SCE to serve supplemental testimony in their

[14] Joint IOU Comments on April 2024 Ruling at 9.

[15] Joint IOU Comments on April 2024 Ruling at 9.

[16] On February 2025, an ALJ ruling was issued that consolidated A.24-06-014 and A.24-12-008.

[17] Joint IOU Comments on April 2024 Ruling at 9.

respective proceedings to comply with the guidance for DF Rate Proposals in this decision within 45 days of the issuance of this decision.

4. Marginal and Non-Marginal Costs in DF Rate Proposals

Demand flexibility is the ability of customers to change their electricity consumption patterns on an hourly, sub-hourly, or real-time basis. Customers may exercise this opportunity to respond by shifting electricity demand (also known as load) based on the price of retail electricity.

The retail price of electricity paid by customers is set to enable recovery of all the IOU's revenue requirement authorized by the Commission in the IOU's GRC Phase 1 proceeding. The Commission has long adopted a marginal cost of service methodology to allocate IOU authorized revenues to customer classes that are used to develop retail rates. [18] In each IOU's GRC Phase 2 regulatory proceeding, the Commission determines the IOU's marginal costs, which represent the costs incurred by IOUs to serve an additional unit of demand in each hour or an incremental customer.[19] There are numerous marginal cost components that are also established based on the IOU's marginal cost of service study.

For time-varying retail rates, such as Time-of-Use (TOU) rates, the retail price for a given time-period is based on the IOU's time-varying marginal costs. These time-varying marginal costs include several key components:

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[18] Marginal cost ratemaking entails setting rates based on the additional or marginal cost required to serve an additional or marginal customer.

[19] ISO New England - FAQs: Locational Marginal Pricing. Available at: https://www.iso-ne.com/participate/support/faq/lmp#:~:text=of%20the%20LMP%3F-,What%20is%20locational%20marginal%20pricing%3F,limits%20of%20the%20transmission%20system.

1. **Marginal Energy Cost (MEC):** the hourly per-unit cost of wholesale electricity to serve customer demand.
2. **Marginal Generation Capacity Cost (MGCC):** the cost of procuring additional generation capacity (*i.e.,* generation resources) to reliably meet system peak demand.
3. **Marginal Distribution Capacity Cost (MDCC):** the cost of expanding distribution infrastructure to reliably deliver an incremental unit of electricity.
4. **Marginal Transmission Capacity Cost (MTCC):** the cost of expanding transmission infrastructure to reliably transport an incremental unit of electricity.

The marginal energy cost is the cost incurred to procure energy from CAISO-operated wholesale electricity market ($/kWh). Marginal capacity costs reflect the investments needed in generation and grid resources to reliably serve electric load during peak demand periods and are typically expressed in normalized dollars per kilowatt per year ($/kW-year). While not formally categorized as a marginal cost, the cost of energy lost through transmission and distribution lines is another incremental time-varying cost.

Beyond these time-varying marginal costs, IOUs must also recover other marginal costs, such as the Marginal Customer Access Cost, which include costs for transformers, service drops, and meters and associated operations & maintenance costs for each additional customer. In addition, retail rates are designed to recover non-marginal costs, which include expenses related to wildfire mitigation costs, above market legacy contracts, and various policy programs. These costs are also incorporated into retail rates and must be carefully considered in the design of DF rates to ensure full revenue recovery while maintaining efficient price signals.

The following sections will examine how these various cost components should be incorporated into DF rates to provide accurate price signals that promote economically efficient load shifting to periods when electricity costs and GHG emissions are lower, how they address affordability, and how they support grid reliability. We also address whether and how marginal cost components should be periodically updated to reflect changing market conditions and system needs.

Finally, we will determine if a pilot is warranted that could help us evaluate the ability of customers to respond to DF rates with electricity prices set on the day when electric demand is needed.

4.1. Marginal Energy Costs in DF Rate Proposals

In an IOU's marginal cost of service proceeding, the GRC Phase 2 proceeding, an IOU's MEC is typically determined by its wholesale electricity procurement costs. The price for wholesale electricity is determined in wholesale electricity markets where generators submit offers to sell energy to LSEs. These markets continuously balance electric supply with real-time changes in demand. CAISO manages the flow of electricity, maintains electric system reliability, and operates a wholesale electricity market across 80 percent of California's electric transmission grid. In CAISO's day-ahead hourly market, scheduling coordinators (entities authorized to transact in the CAISO market) submit bids to purchase electricity starting seven days before the corresponding day when electricity is needed to serve load. The CAISO day-ahead market price for electricity is set at 1:00 p.m., the day before electricity is needed to serve electric load.[20] This process establishes schedules for power plants to dispatch electricity

[20] The settled price in CAISO's day-ahead market is based on the supply and demand for electricity, which is reflected by the number and price of bids from LSEs to purchase electricity and offers from generators to sell electricity.

and sets the corresponding day-ahead prices. The bulk of electric demand for LSE customers is typically scheduled through the day-ahead market.[21]

To satisfy adjustments and increments of electric demand not covered in the day-ahead schedules, CAISO operates a day-of, real-time market, which includes both a 15-minute market and a 5-minute market.[22] The day-of, real-time market provides scheduling coordinators with flexibility to supply needed electricity in the event of fast-changing grid conditions or forecast inaccuracy.

For both the day-ahead and day-of markets, CAISO utilizes a market optimization model to calculate locational marginal prices at specific points on the transmission grid called Pricing Nodes. These Pricing Nodes are locations on the CAISO controlled grid that represent generation facilities, load centers, and transmission network interconnection points.[23] Locational Marginal Prices reflect the cost to deliver electricity to specific locations on the grid, primarily driven by the cost of available generating resources, physical transmission constraints that may limit power flows, and transmission losses that occur as electricity travels through the network.

The price for wholesale electricity purchased by utilities to serve their customers is based on Locational Marginal Prices at Distribution Load Aggregation Points, which are predefined geographic regions representing aggregated customer load within an IOU's service territory where energy is priced, scheduled, and settled. Distribution Load Aggregation Points simplify

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[21] *See* Attachment A to D.22-08-002 at 19. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K429/496429610.PDF.

[22] CAISO Market Process and Products Description. Available at: http://www.caiso.com/market/Pages/MarketProcesses.aspx.

[23] CAISO Market Process and Products Description. Available at: http://www.caiso.com/market/Pages/MarketProcesses.aspx.

market operations by allowing IOUs to transact for their bundled customer load as a consolidated entity rather than at individual Pricing Nodes. The prices at Distribution Load Aggregation Points form the foundation of the MEC component in retail rates.

Summary of MEC Proposals

We will now present and summarize proposals from Staff, the Joint IOUs, and Microgrid RC concerning the incorporation of MEC in DF rates.

The Staff proposes that the Large IOUs should use CAISO Locational Marginal Prices at Distribution Load Aggregation Points in the day-ahead market to represent the MEC in their DF rates. The Staff asserts that this approach provides customers with a degree of rate certainty. Because LSEs purchase the bulk of their electricity in the day-ahead market at Distribution Load Aggregation Point prices, these prices reflect a majority of their actual energy purchase costs. [24]

The Joint IOUs also propose that initial DF rates should use the day-ahead Distribution Load Aggregation Point price to set MECs. To this point, the Joint IOUs state that a large majority of electricity is purchased in the CAISO day-ahead market at the Distribution Load Aggregation Point price. According to the Joint IOUs, customers can more easily understand and shift load in response to hourly day-ahead market prices versus day-of real-time market prices. The Joint IOUs also suggest that customers prefer notifications about day-ahead market prices compared to day-of market prices.[25]

[24] Working Group Report at 11.

[25] Working Group Report at 75.

In contrast to Staff and the Joint IOUs, Microgrid RC contends that the wholesale price for electricity should be based on CAISO day-of market prices at Pricing Nodes in the CAISO network. Microgrid RC suggests that further evaluation is needed to determine if the wholesale electricity component of DF rates should be based on CAISO's 15-minute or 5-minute day-of market prices. In support of their position, Microgrid RC states that CAISO day-of market prices are designed to reflect the real-time (i.e. short-run) marginal cost for both energy *and* transmission at each Pricing Node.[26]

***Comments* on MEC Proposals**

Rondo Energy, Sierra Club, SBUA, Valley Clean Energy (VCE), Polaris Energy Services (PES), and Gridtractor support the Staff's proposal to initially offer DF rates with CAISO day-ahead hourly prices at Distribution Load Aggregation Points.[27] Cal Advocates, CalCCA, Sierra Club, VCE, PES, and Gridtractor also support the Joint IOUs' proposal, which is similar to Staff's proposal.[28]

CalCCA and Sierra Club claim that a DF rate that includes a day-ahead hourly price versus a day-of price will be easier for customers to understand.[29] [30] CLECA also favors Staff's and the Joint IOUs' proposals to initially offer CAISO day-ahead hourly prices in DF rates, but asserts that day-of prices may work for large customers, that also can weather potential bill volatility, and customers with smart appliances that are connected to demand aggregators or

[26] Working Group Report at 149.

[27] Working Group Report at 16-17.

[28] Working Group Report at 83-87.

[29] Working Group Report at 15.

[30] Working Group Report at 16.

"arbitragers." However, small customers may not have access to smart technologies that provide these benefits. Additionally, CLECA maintains that initially offering day-of wholesale electricity prices in DF rates could be costly to implement. For this reason, CLECA suggests that the current SCE DF pilot authorized by D.24-01-032 could inform whether and to what extent day-of wholesale prices in DF rates are a viable option.[31]

350 Bay Area generally supports the Staff and the Joint IOU proposals but more broadly advocates that all long- and short-run marginal costs should be incorporated in wholesale hourly prices in DF rates to provide appropriate and effective prices signals to customers, including those that own, operate and/or manage distributed energy resources (DERs).[32] Accordingly, 350 Bay Area opposes Microgrid RC's proposal that the wholesale price for electricity should only consider generation costs and exclude transmission and distribution (T&D) marginal costs (both short run and long run). Further, 350 Bay Area points out that T&D and locational components are required to comply with the CEC LMS under Sec 1623(a)(1).[33]

Cal Advocates does not support Microgrid RC's proposal because it is too complex for the typical residential customer, has not been piloted, and includes unknowns.[34] Because day-of prices are difficult to forecast, the Joint IOUs suggest that Microgrid RC's proposal to include day-of prices in DF rates would make it difficult for third-party service providers to manage and could reduce

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[31] Working Group Report at 15.

[32] DERs include but are not limited to electric vehicles, solar systems, and storage systems that can be owned, operated, or managed as individual or integrated resources.

[33] Working Group Report at 155.

[34] Working Group Report at 156.

customer adoption. Further, the Joint IOUs state that most energy procurement costs are incurred in the day-ahead market.[35]

<u>Guidance on MECs in DF Rate Proposals</u>

After a review of the record, the Commission agrees with the Staff Proposal and the Joint IOUs that it is reasonable that the Large IOUs should use CAISO's day-ahead energy market price at Distribution Load Aggregation Points as the MEC in DF Rate Proposals. As highlighted by 350 Bay Area, inclusion of CAISO's day-ahead hourly prices in DF rates also satisfies CEC Load Management Standard requirements.

Given the uncertainties and implementation challenges, we agree with Cal Advocates that Microgrid RC's proposal to include day-of real-time prices (*i.e.* marginal energy prices that vary in real time in 15-minute or 5-minute intervals) in DF rates may be too complex for most residential customers, and with CLECA that its benefits would likely only be realized by customers with access to smart technologies that can automatically respond to price signals. To this point, Sierra Club and CalCCA provide a sound rationale that a day-ahead hourly price in DF rates will be easier for customers to understand and respond to than one with a day-of real-time price. As suggested by CLECA, information obtained from DF pilots could inform potential future incorporation of day-of real-time prices in subsequent iterations of DF rates.

For these reasons, we reject Microgrid RC's proposal to include day-of prices in DF rates at this time.

[35] Working Group Report at 158.

4.2. Marginal Cost of Energy Losses in the Transmission and Distribution System

Electricity is lost when it is delivered to customers through T&D lines. The primary factor that influences the amount of lost electricity or energy is the loading level of each T&D network segment, or the level of current flowing through the lines. These losses increase quadratically as the level of current in a line approaches its rated capacity, or the amount of power the T&D line can handle without causing damage.[36] Other factors, such as temperature, also influence the percentage of electricity that is lost. Consequently, IOUs must procure additional energy to compensate for these losses; for example, if the annualized T&D losses amount to 10%, an IOU must procure an extra 10% of electricity above its sales to meet customer demand. Moreover, line losses necessitate that IOUs appropriately size their generation, transmission, and distribution capacity resources to ensure reliable electric service.

During periods of high T&D capacity utilization, the non-linear nature of line losses means that marginal losses can disproportionately affect an IOU's total annual average losses and associated revenue requirements. Furthermore, electricity line losses are higher for customers receiving electric service at lower voltage levels further downstream in the T&D network compared to those at higher voltage levels.

In the context of DF rates, properly accounting for these losses is essential to accurately reflect the true cost of delivering electricity to customers during different time periods and at various locations within the T&D system.

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[36] "Bill Impacts of Dynamic Pricing on California Customers: Inelastic Study" Presentation to Working Group 1 of the Demand Flexibility Proceeding, Lawrence Berkeley National Laboratory, January 20, 2023. - Working Group Report, Appendix 2 at 20.

Summary of Proposals for Cost Recovery of T&D Losses

We now review proposals from Staff, the Joint IOUs, and Microgrid RC to determine how costs from T&D losses should be reflected in DF rates. Subsequently, we will present party comments that reflect their views and recommendations on these proposals.

Staff propose that DF rates should include a price component to recover revenues associated with electricity losses in the IOU's T&D network. According to Staff, a quadratic function of the IOUs' T&D network load should be used to calculate the price to recover annual line losses, based on a methodology proposed by SCE in its dynamic rate pilot, pursuant to D.21-12-015. In Advice Letter (AL) 4684-E-A, approved by Staff, SCE explains its rationale:

> SCE's chosen quadratic price curve is intended to recover fixed costs along the entire duration of the load curve, as opposed to the typical applications of concentrated fixed cost recovery used in standardized time of use (TOU) rate design.[37] Concentrated recovery of fixed costs using a flat-adder threshold basis can cause steep cross-hour price differentials that are likely to be bypassed by resources that are acutely flexible and can create compounding effects on cross-hour load impacts on the grid. SCE believes that the formulaic definition of these dynamic price curves can be refined through iterative cycles and regression analysis on the causal effects of price on load determinants and/or customer responsiveness. However, SCE believes that the continuity of recovery along the entire duration of the load curve is an important element that should be considered in the determination of a price function for long-run fixed cost recovery.[38]

[37] Time-of-Use rates are based on the time when electricity is used, which generally tracks the cost of electricity generation at the time.

[38] *See* SCE AL 4684-E-A.

Staff also suggests that IOU DF Rate Proposals should consider whether other factors, such as temperature and distribution voltage level, should be used to modify the distribution loss recovery price component to better reflect cost causation of line losses.[39]

The Joint IOUs recommend that DF Rate Proposals should include a factor that accounts for line losses, which may differ depending on customer voltage level or other factors.[40] To meet customer demand, the Joint IOUs explain that additional generation must be procured to cover losses from the transmission system where CAISO prices are set.[41] Further, the Joint IOUs note that customers receiving electric service at lower voltage experience greater a loss of electricity. However, the Joint IOUs also claim that modelling the dependency of line loss on current and temperature, another influential factor, could result in false precision in the relationship between those factors and the revenues associated with T&D losses.[42]

Microgrid RC proposes that the CAISO wholesale price should be the principal variable element in a DF tariff. That is, the price for electricity should equal the real-time marginal cost of delivering it to a particular location given T&D constraints and line losses.[43]

Comments on Proposals for Cost Recovery of T&D Losses

According to 350 Bay Area, line losses more than double as T&D lines approach their capacity rating, and that this doubling factor alone reflects a

[39] Working Group Report at 12-13, Footnote 9.

[40] Working Group Report 77.

[41] Working Group Report at 77.

[42] Working Group Report at 77.

[43] Working Group Report at 149.

difference of at least 7% (i.e., 7% of all electricity generated is lost) that is spread equally between T&D losses. Given that, 350 Bay Area suggests that electricity line losses calculations should be time dependent.[44]

The Joint IOUs,[45] Rondo Energy,[46] and SBUA[47] broadly support Staff's line loss proposal. Cal Advocates agrees that a line loss factor should be a component of DF rates, and suggests that Staff's proposal does not provide adequate supporting evidence that a quadratic function is the most optimal method to calculate T&D line losses.[48]

Guidance on Cost Recovery of T&D Losses

Regardless of the precision of line loss estimates, the IOUs incur costs to replace significant amounts of lost electricity to deliver electricity during periods of high T&D load. Several parties, including the Joint IOUs, concur that a T&D line loss price component should be included in proposed DF rates to recover this cost. We agree.

We do not agree, however, with Microgrid RC that the CAISO wholesale price for electricity, or MEC, reflects the replacement cost for electricity that is lost during its delivery during high-load periods. Microgrid RC appears to refer to the "Marginal Cost of Losses" or "MCL" variable in CAISO's Locational Marginal Price algorithm as support for it position. That variable represents the marginal losses in the high-voltage transmission network. However, the MCL does not account for all the physical losses experienced by IOUs when delivering

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44 Working Group Report at 13, at 82, and at 156

45 Working Group Report at 15.

46 Working Group Report at 16.

47 Working Group Report at 16.

48 Working Group Report at 14.

electricity purchased at the Distribution Load Aggregation Point to its customers. IOUs must purchase more electricity than its customers consume to account for both transmission *and* distribution losses. IOUs allocate non-zero loss factors even for their transmission-connected customers.

Despite differing party opinions on the most valid methodology to calculate line loss factors, parties expressed consensus that a line loss factor should be included in DF Rate Proposals. Accordingly, it is reasonable to require the Large IOUs to include a line loss price function in the MEC in their DF Rate Proposals to recover the cost of replacement electricity.

While questioning the details of Staff's proposal, Cal Advocates does not provide a more reasonable and accurate methodology for incorporating line losses into DF Rates, nor does it provide an assessment regarding why the use of a line loss price component that is a quadratic function of IOU load, as proposed by SCE in AL 4684-E-A and approved by the Commission, is not warranted.

Therefore, it is reasonable to require that the Large IOUs' proposed methodologies to calculate line losses reflects the time or load-dependent nature of these losses. Further, we agree with 350 Bay Area's contention that line loss prices should be a function of load forecasts, which reflect the IOU's actual time-varying load. Therefore, we conclude that the Large IOUs should use a price function that is a function of the IOU's load forecast (such as a quadratic or similar price function) instead of applying a uniform scaling factor to the MEC price component in their DF Rate Proposals to recover the cost of electricity that is lost due to delivery through T&D lines.

4.3. Marginal Generation Capacity Cost

MGCC is the cost to procure and maintain sufficient generation capacity to reliably serve an incremental unit of electric demand at all times, including during peak demand and ramping periods. Ramping or flexible resources are crucial for balancing electricity generation and demand during periods when the IOU's net load or supply change rapidly, such as when solar generation declines in the evening while system demand simultaneously rises. MGCCs are typically measured in dollars per kilowatt per year ($/kW-year). This metric reflects the annual cost to procure sufficient generation capacity with the capability to ramp and/or meet peak demand.

Long run MGCC is based on the cost to construct and operate the cheapest new power plant, whereas short-run MGCC is the cost to continue to operate the most expensive existing power plant.[49]

As discussed in the Working Group Report, parties note the CEC Load Management Standard requirement that demand flexibility 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)."[50]

Several proposals in the Working Group Report recommend that the MGCC component for a dynamic marginal cost-based rate should be designed to annually recover an IOU's MGCC, based on what is approved by the Commission in an IOU's most recent GRC Phase 2 application. However, the GRC Phase 2 approved MGCC may not be an up-to-date representation of the IOU's actual cost to procure sufficient generation capacity to meet its system reliability needs during the attrition years of a GRC Phase 2 cycle.[51]

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49 D.23-04-040, Appendix A, at 1.

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

51 D.21-11-016 at 49-53. Attrition is the year-to-year decline in a utility's earnings caused by increased costs which are not offset by increased rates and sale. D0202043 Opinion Authorizing

Staff MGCC Proposal

Staff proposes that DF rates should include a dynamic MGCC price element calculated with a "scarcity price" that is a function (either quadratic or other polynomial) of net load (either IOU or CAISO) and recovers all revenues associated with an IOU's long-run MGCCs. This approach sets higher capacity prices during periods of high grid stress (high net load) and lower prices when excess capacity is available, creating economically efficient price signals that reflect the actual cost of maintaining sufficient generation capacity to meet peak demand. Customers who use energy during high grid stress periods would pay more, incentivizing load shifting to periods of lower system stress.

Staff proposes that the MGCC price element should include two components: (1) a peak MGCC component based on forecasted peak system net load, or peak system load net of renewables generation and (2) a flex MGCC price component based on the forecasted 3-hour system net load ramp, *i.e.,* the 3-hour period when customer demand rapidly rises to the peak load net of renewables generation.

Staff elaborates on its approach as follows:

1. The IOU's MGCC value (measured in $/kW-year) should be used to calibrate the MGCC price element such that the projected annual revenues, when divided by the system peak load, equal the MGCC value.
2. Each IOU should be required to submit proposals for two distinct MGCC price components: (a) a peak MGCC component based on a polynomial function (*e.g.,* quadratic) of forecasted system net load and (b) a flex MGCC

an Attrition Rate Adjustment Increase of $150,838,000 (ca.gov). Available at: https://docs.cpuc.ca.gov/published/Final_decision/13551-03.htm.

component based on a polynomial function (*e.g.*, quadratic) of forecasted 3-hour system net load ramps;[52]

3. The MGCC prices for imported electricity can be scaled using the equal percent of marginal cost (EPMC) methodology to recover an appropriate portion of an IOU's non-marginal costs, ensuring revenue neutrality while maintain economically efficient price signals.[53]

<u>Joint IOUs MGCC Proposal</u>

Unlike Staff's proposal that would set the peak MGCC price only as a function of forecasted peak system net load, the Joint IOUs propose that the dynamic MGCC price element in DF rates should reflect the likelihood and/or occurrence of CAISO Alerts, Warnings, and Emergencies that serve as indicators of grid stress, i.e., when operating reserves fall below certain predetermined levels. In support of their proposal, the Joint IOUs highlight empirical evidence showing that not all high load hours reflect constrained generation capacity.[54]

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[52] Working Group Report at 37.

[53] Revenue neutrality is the concept that a utility's rates are designed with the intent to recover all authorized revenues.

[54] CAISO Alerts, Warnings, and Emergencies are emergency notifications that are sent to notify utilities, transmission operators, and customers about potential or impending electricity shortages. AWEs include (1) Flex Alerts that request customers to conserve electricity when supply may not be adequate to meet demand, ideally issued a day in advance, (2) Restricted maintenance operations alerts requesting utilities and transmission operators not to take grid assets off-line when electric demand is high, issued in real-time or in advance, (3) Transmission emergencies for periods when transmission grid capability is threatened or limited, issued in real time (4) Alerts to conserve when CAISO determines that electricity deficiencies are expected, issued the day ahead by 3:00 p.m. (5) warnings, issued in real time (6) Stage 1 Alerts indicating all generation resources are in use or committed for use, issued in real-time (7) Stage 2 Alerts indicates emergency programs have been activated, issued in real time, and (8) Stage 3 Alerts, grid operator cannot meet reliability, issued in real time https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf.

As such, the Joint IOUs proposal includes the following recommendations for the MGCC price element in DF rates:[55]

1. MGCC prices should be scaled with the degree and severity of CAISO Alerts, Warnings, and Emergencies.
2. MGCC prices should include a capacity price adder during Flex Alerts to align with customer-focused CAISO communications and calls on demand response (DR) programs that are triggered by system conditions such as the Emergency Load Reduction Program. [56]
3. MGCC prices should reflect CAISO-wide or IOU service-territory-wide net load, possibly adjusted for non-renewable GHG-free generation.
4. MGCC prices should reflect Western Electricity Coordinating Council-wide conditions,[57] because, as stated by CAISO and corroborated by PG&E's MGCC Working Group data, [58] conditions in the rest of Western Electricity Coordinating Council affect reliability in California. Temperature data, as used by PG&E's MGCC Working Group, could serve as a metric to reflect Western Electricity Coordinating Council-wide conditions.

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[55] Working Group Report at 76.

[56] The Emergency Load Reduction Program is a 5-year pilot program designed to pay electricity consumers for reducing energy consumption or increasing electricity supply during periods of electrical grid emergencies. The Emergency Load Reduction Program is managed by PG&E, SDG&E, and SCE. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

[57] The Western Electricity Coordinating Council is a non-profit corporation that exists to ensure the bulk electric system reliability in the Western Interconnection, that includes 14 western states, two Canadian provinces, and Northern Baja Mexico.

[58] Marginal Generation Capacity Cost Pricing Formula for PG&E's Day-Ahead Hourly Real-Time Pricing (DAHRTP) Rates, Report to Parties in California Public Utility Commission dockets A.20-10-011 and A.19-11-019, Corrected Version Filed March 17, 2022 (MGCC Study). Presented to Working Group 1 by the MGCC Working Group (PG&E, California Large Energy Consumers Association, Cal Advocates, Small Business Utility Advocates, and Enel-X) February 17, 2023.

If ramping or flex MGCCs are significantly above zero, the Joint IOUs recommend the design of an evidence-based method to allocate these costs to hours when grid stress, or its equivalent, occurs. To design such a method, the Joint IOUs propose that IOUs initiate a study like PG&E's MGCC Study that includes the following components:

1. Design an evidence-based method to identify hours associated with high-ramp periods when grid stress, or its equivalent, is present or renewable resource curtailments occur; and
2. Identify resource requirements needed to mitigate identified grid stress, or its equivalent, associated with high-ramp periods, such as ramp generation capacity, and/or any special methods required for valuation.

The Joint IOUs explain that each IOU individually analyzes and determines the percentage of the total MGCC that may be allocated towards either peak or flex generation capacity in its respective GRC Phase 2 proceeding (*i.e.* PG&E and SDG&E allocate 0% of MGCC to flex generation capacity, while SCE allocates 40% of MGCC to flex generation capacity). While each IOU may choose differing allocation approaches, a common understanding of flex MGCC would help advance the common goals of cost reduction, emissions reduction, and maintained or increased reliability.[59]

<u>Microgrid RC MGCC Proposal</u>

Microgrid RC proposes that a "Variable Energy Price" should be the principal dynamic price element in a DF rate, calculated as the sum of (1) the CAISO real-time wholesale market price and (2) a Distribution Congestion

[59] Working Group Report at 76-77.

Adjustment that "reflects the locational marginal cost of delivering energy at each priced point on the distribution system."[60]

Microgrid RC states that in CAISO markets higher-priced resources must be utilized in transmission-constrained areas to satisfy demand not met by resources within the constrained area. On this basis, Microgrid RC asserts that CAISO wholesale prices include both the MEC and short-run marginal costs associated with system-level generation capacity and transmission constraints. Microgrid RC argues that this congestion pricing component of the wholesale price is equivalent to what other party proposals refer to as short-run MGCC and MTCC.

Microgrid RC proposes that the Variable Energy Price should not include any additional long-run marginal capacity costs as they are determined in GRC Phase 2 proceedings and are more relevant for revenue allocation among customer classes than for setting real-time price signals.[61] Instead, Microgrid RC recommends only the addition of a Distribution Congestion Adjustment to the wholesale price to account for short-run distribution-level congestion. Microgrid RC defines the congestion price as the price differential for electricity in constrained versus unconstrained areas, which equals the marginal cost of delivery or capacity in the constrained area.[62]

Microgrid RC argues that energy-only products should not receive any capacity payments other than the real-time congestion components already

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[60] Working Group Report at 149.

[61] Long run marginal generation capacity cost is based on the cost to construct and operate the cheapest new power plant, where short-run marginal generation capacity cost is the cost to continue to operate the most expensive existing power plant. D.23-04-040, Appendix A, at 1.

[62] Working Group Report at 149.

embedded in the wholesale energy price and its proposed Distribution Congestion Pricing Adjustment. Alternatively, Microgrid RC suggests that capacity payments should be provided under a separate emergency capacity tariff that pays DERs "for capacity that is the performance-based equivalent of the resource adequacy (RA) payment for being available for dispatch during periods of grid stress for up to a limit such as 200 hours per year."[63] Microgrid RC asserts that firm capacity payments through such a mechanism will support customer investment in DER, whereas the Staff and Joint IOU proposals for dynamic prices for long-run marginal capacity costs (for generation, transmission, and distribution capacity) will not.[64]

<u>Comments on MGCC Proposals</u>

350 Bay Area favors the inclusion of short-run and long-run marginal costs to provide customer and DER price signals.[65] Cal Advocates generally supports Staff's recommendation to include a MGCC price in DF rates,[66] but prefers the Joint IOUs' proposal to incorporate CAISO Alerts, Warnings, and Emergencies to scale MGCCs and initiate a study of cost-based approaches to set prices for flex MGCC.[67] CLECA supports an hourly price for MGCC in DF rates and suggests that the MGCC price should be based on a methodology that allocates long-run MGCC to hours of grid stress and includes all grid-stress factors. [68]

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[63] Working Group Report at 172-173.

[64] Working Group Report at 85-86.

[65] Working Group Report at 82.

[66] Working Group Report at 14.

[67] Working Group Report at 83.

[68] Working Group Report at 84.

Microgrid RC opposes the inclusion of long-run marginal costs in dynamic prices.[69] 350 Bay Area[70] and Sierra Club[71] claim that Microgrid RC's proposal to exclude long-run MGCC in DF rates would be non-compliant with the CEC's Load Management Standards that require inclusion of MGCCs in DF rates.

Both Sierra Club and Cal Advocates voice concern that Microgrid RC's proposed inclusion of a Distribution Congestion Adjustment in DF rates would unfairly assign electricity costs to low-income customers in neighborhoods where distribution system congestion might be more prevalent.[72]

Similarly, CalCCA states that CCAs have diverse loads, customer demographics, and community priorities that will require each CCA to individually identify the correct methodology, including one to develop MGCCs, to set various DF rate elements.[73]

SEIA recommends that MGCC values in DF rates should have distinct flex MGCC and peak MGCC components, send a daily versus an event-based price signal, and reflect the experience of California's Critical Peak Pricing program to refine the scarcity price signal.[74] [75] SEIA also proposes that MGCC values should be based on cost assumptions adopted in the Integrated Resource Planning (IRP) proceeding to provide a uniform MGCC value for all three IOUs based on

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[69] Microgrid RC Reply Comments on April 24, 2024 ALJ Ruling at 1-2.

[70] Working Group Report at 155.

[71] Working Group Report at 158-159.

[72] Working Group Report at 156.

[73] Working Group Report at 84.

[74] SEIA Opening Comments to April 24, 2024 ALJ Ruling at 5-8.

[75] Critical Peak Pricing is an electric rate in which a utility charges a higher price for consumption of electricity during peak hours on selected days, referred to as critical peak days or event days.

up-to-date IRP data, that is used by Staff as an input to the Avoided Cost Calculator (ACC).[76] [77] To support their proposal, SEIA claims that many GRC Phase 2 proceedings adopt MGCCs in party settlements that do not represent actual costs and are only utilized for specific purposes such as revenue allocation or rate design.[78] Further, SEIA notes that the Commission demonstrated in D.21-11-016, adopted in PG&E's 2020 GRC Phase 2 proceeding, that MGCCs should be consistent with the Commission's IRP planning assumptions.[79]

The Joint IOUs assert that SEIA's proposal to use IRP-based MGCCs is outside of the scope of this proceeding and would inappropriately inhibit GRC Phase 2 proceedings.[80] Further, the Joint IOUs argue that while certain input factors are considered in the IRP to calculate the MGCC, there are other factors such as (1) flexible capacity costs and specific loading factors, (2) different forecasted energy costs between MGCC and MEC that impact the MGCC calculation and (3) variation in marginal resource used to calculate MGGC (*i.e.* battery storage resources may not always be the marginal resource).[81]

Guidance on MGCCs

The Joint IOU and Staff proposals show good cause for including MGCCs in DF Rate Proposals and comply with CEC Load Management Standard requirements. Including MGCCs can promote DF during peak and ramping

[76] The details of this calculation are in the "2022 ACC Capacity Avoided Cost v1b.xls" spreadsheet that is part of the approved 2022 ACC, which was adopted in Resolution E-5228 in accordance with D.22-05-002 in the R.14-10-003 proceeding.

[77] SEIA Opening Comments to April 24, 2024 ALJ Ruling at 5-8.

[78] SEIA Opening Comments on April 24, 2024 ALJ Ruling at 1-2.

[79] SEIA Opening Comments on April 24, 2024 ALJ Ruling at 6.

[80] Joint IOUs Reply Comments on April 24, 2024 ALJ Ruling at 6.

[81] Joint IOUs Reply Comments on April 24, 2024 ALJ Ruling. at 6-7.

periods and incentivize exports from DERs to support grid operations in an economically efficient manner. MGCCs in DF rates must also send appropriate price signals to promote load shifting to enhance system reliability and minimize renewables curtailment. Therefore, in agreement with the Staff Proposal and the Joint IOUs, it is reasonable that the MGCC price in Large IOU DF Rate Proposals must account for costs associated with both peak and flexible capacity needs during periods of grid stress.

Due to year-to-year changes in grid conditions that impact year-to-year costs, it is also reasonable for Large IOUs to update the amount of revenue or costs that the MGCC price intends to recover on an annual basis in DF rates.

Further, it is reasonable for the Large IOUs to develop MGCC price elements in their DF Rate Proposals as follows:

1. DF rates should include an MGCC price component based on long-run marginal costs;
2. MGCC price should be scaled to recover all long-run marginal generation capacity costs;
3. DF rates should include a peak MGCC price component that is a function of system net load; and
4. DF rates should include a flex MGCC price component to provide a daily load shift price signal that supports system ramping needs and reduces renewable curtailment.

We discuss the above guidance in detail in the following paragraphs.

<u>DF rates should include an MGCC price component based on long-run marginal costs.</u>

We agree with Cal Advocates that DF Rate Proposals must include a price component that recovers an IOU's MGCC revenues to ensure that generation capacity costs are appropriately reflected in DF rates. Further, we agree with CLECA that MGCCs in DF Rate Proposals must reflect long-run marginal costs.

because this approach: (1) sends a strong DF signal and aligns with long-standing Commission practice and rate design principles, (2) ensures that the DF price accurately incorporates scarcity costs for available generation capacity, (3) improves the accuracy of the scarcity price signal that promotes long-term cost savings through improved grid utilization and efficiency, and (4) incentivizes customer behavior that can reduce future generation capacity-related costs.

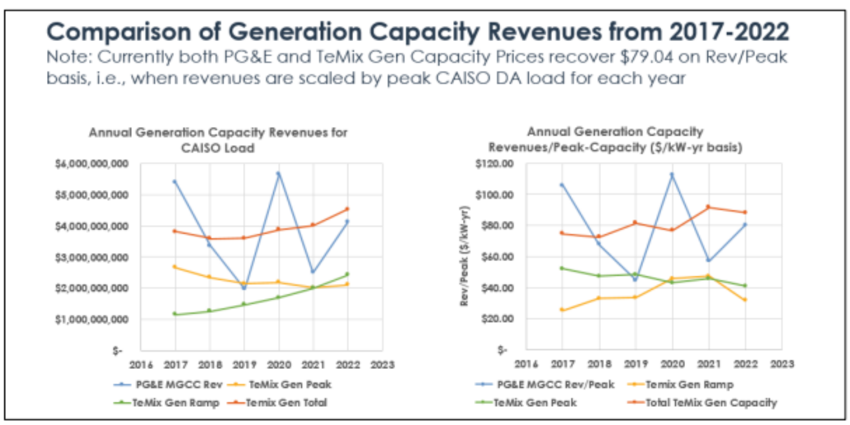
Microgrid RC proposes to exclude long-run marginal costs in MGCCs and instead provide capacity contracts to individual customers for firm forward commitments. We believe, however, that dispatch features that provide capacity contracts would require significant administrative overhead and are not proven to be based on cost causation. Further, Microgrid RC's proposal would not be compliant with the CEC Load Management Standard that requires MGCCs to be included in DF rates. We also share Sierra Club's and Cal Advocates' concern that Microgrid RC's proposal to include a Distribution Congestion Adjustment in DF rates would unfairly assign electricity costs to customers in low-income neighborhoods where congestion on distribution networks may occur. For these reasons, we reject Microgrid RC's proposal.

DF rates should include a peak MGCC price component that is a function of net system load.

The procurement of peak capacity resources is driven by the need for additional generation capacity to reliably meet system net peak load. Because the periods that drive the need for additional resources for system reliability are often related to CAISO-wide grid conditions and constraints, we agree with the Staff Proposal and the Joint IOUs that either IOU net load or CAISO-wide net load are both reasonable inputs for a peak MGCC price function.

Unlike the Joint IOUs' proposed sigmoidal MGCC function, Transactive Energy Services' or TeMix's proposed quadratic MGCC function, which is recommended in the Staff Proposal, would recover revenues across all net load conditions versus only in the highest net load hours in a year and consequently provides greater annual revenue recovery stability.[82] Figure 1 shows that both the TeMix quadratic MGCC functions, an integral part of the Staff proposal, and the PG&E sigmoidal MGCC functions recover the same revenues from 2017 to 2022.[83] However, the PG&E sigmoidal MGCC price function exhibits significantly higher variability in revenue recovery across consecutive years due to the concentration of revenue recovery into a smaller subset of net load conditions.

Figure 1. TeMix/Joint IOU 2017-22 MGCC Price Functions and Revenue Recovery



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[82] Working Group Report, Appendix 1 at 690.

[83] This analysis compares the 2022 revenue recovery of generation capacity between the VCE/TeMix Agricultural Pumping Pilot MGCC price with peak and ramp capacity prices and the PG&E *Day* Ahead Hourly RTP *(*DAHRTP*)* MGCC price with only a peak capacity price. Both the VCE/TeMix and the PG&E DAHRTP MGCC prices are calibrated to achieve the same annual revenue recovery. However, due to distinct design approaches, there is a greater degree of variation in the generation capacity revenue recovery from the PG&E DAHRTP MGCC price when compared to the VCE/TeMix *MGCC* price. Working Group Report at 39, Figure 11.

Based on our review, we find merit in aspects of both proposals. While the sigmoidal function recommended by the Joint IOUs and supported by Cal Advocates may provide stronger price signals during peak conditions, the quadratic function recommended by Staff may provide more stable revenue recovery. Therefore, we will not prescribe a specific mathematical function for the relationship between peak MGCC price and net load. Instead, it is reasonable to direct the Large IOUs to propose a functional relationship between the peak MGCC price and net load in their DF Rate Proposals that best balances strong price signals with revenue stability considerations. The IOUs may propose to use a sigmoidal function, quadratic function, or another function that appropriately relates peak MGCC prices to system net load.

The IOUs may also incorporate other relevant factors into their peak MGCC price functions, such as CAISO Alerts, Warnings, and Emergencies. Similar to the analysis presented in Figure 1, it is reasonable to require that Large IOU DF Rate Proposals must also include a detailed evaluation to demonstrate how the proposed MGCC price function (1) does not unreasonably impact annual revenue recovery stability and (2) performs across a range of system conditions and years. Further, it is reasonable to require that each Large IOU's MGCC price function evaluation in their DF Rate Proposals should include a comparison of revenue recovery variability with alternative functional approaches.

DF rates should include a flex MGCC price component to provide a daily load shift price signal that supports system ramping needs and is designed to promote a reduction in renewable curtailment.

We agree with the Staff Proposal, 350 Bay Area, CalCCA, TeMix, SBUA, SEIA, Rondo Energy and Clean Coalition that DF Rate Proposals must include a flex MGCC price component that supports system ramping needs and reduces renewable curtailment. We agree with such recommendations for the following reasons:

1. **System Reliability**: Ramping resources are critical for maintaining system reliability, especially during periods of rapid changes in net load. Including a flex MGCC price component in DF rates ensures that hourly price reflects the value of load flexibility during ramping periods and encourages customer behavior that can help balance generation and demand during these transition periods.
2. **Renewable Integration**: One of the primary objectives of this rulemaking is to adopt policies that reduce the curtailment of renewable energy and GHG emissions associated with meeting the state's future system load.[84] Effective ramping capabilities are necessary to integrate renewable energy sources into the grid at a lower cost. A specific flex MGCC component creates a clear price signal for load shifting during ramping periods, which can reduce renewable curtailment and support the state's GHG reduction goals.

In the Working Group 1 report, the Joint IOUs point out that the trends of increased renewable generation and end-use electrification are likely to exacerbate the system "duck curve" ramp and potentially create a second annual net peak in the winter.[85] These trends are expected to become more pronounced over longer time frames (over the next 20 years) than are typically reflected in cost of service studies in a GRC Phase 2 cycle.[86] Moreover, the widening gap between the midday trough (*i.e.,* the "belly" of the duck curve) and evening peak (*i.e.,* the "head" of the duck curve) leads to both increased curtailment of

[84] Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates at 1.

[85] Working Group Report at 56.

[86] Working Group Report at 56.

renewables and a greater need to procure additional grid-connected energy storage, which in turn drives up the costs associated with meeting California's clean energy goals.

There is sufficient analysis in the Working Group 1 report to support the hypothesis that by incorporating both peak and flex MGCC price signals, DF rate proposals will better reflect the true costs of maintaining a reliable and resilient electric grid, promote more efficient energy use, and support the State's renewable energy goals.

Therefore, it is reasonable that the Large IOUs' implementation of flex MGCC components should be based on each IOU's current allocation of marginal generation capacity costs to flexible capacity:

1. **For IOUs with existing flexible capacity allocations**: If a non-zero percentage of MGCC has been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as SCE, where 40% of the total MGCC is allocated to flexible capacity), then it is reasonable that each IOU's DF Rate Proposal should include a flex MGCC price component that is calibrated to recover a similar proportion of the MGCC value being used for DF rate design purposes. As described above, this MGCC value may be either from the most recently adopted ACC model, or alternatively the calculated MGCC value from an IOU's latest GRC Phase 2 proceeding testimony. We determine that including a flex MGCC price component has the potential to incentivize DF that can reduce both renewable curtailment and moderate system net-load ramps. IOU DF Rate Proposals may include the flex MGCC price design that is a function of the 3-hour system net load ramp as proposed by Staff and TeMix in the Working Group report.
2. **For IOUs without existing flexible capacity allocations**: If a percentage of the MGCC has not been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as PG&E and SDG&E), then it is

> reasonable to require that IOUs should propose a reasonable non-zero percentage to allocated to flexibility capacity for DF rates in their DF Rate Proposals. The IOU's DF Rate Proposal should include a flex MGCC price component that is calibrated to recover this proposed proportion of the MGCC value being used for DF rate design purposes. These IOUs should also follow the guidance detailed above regarding the design of the flex MGCC price function. (i.e., use of the flexible MGCC price design that is a function of the 3-hour system net load ramp as proposed by Energy Division and TeMix in the Working Group report).

<u>Use of the MGCC derived from IRP Data</u>

Based on our review of the record, we determine that SEIA's proposal for the Large IOUs to use MGGCs in DF Rate Proposals that are derived from input values developed in the IRP proceeding has merit. We acknowledge that Commission-adopted GRC Phase 2 MGCCs are often settled, non-cost-based MGCC values that are used for revenue allocation, achieving specific customer outcomes, or rate design. In contrast, the IRP proceeding establishes and updates key input values for the ACC, including the capital cost of generation resources that is used to derive MGCCs. This is particularly important because the bi-annual updates to the ACC determine the calculations for Net Billing Tariff retail export compensation.[87] [88] To ensure consistent treatment across different customer programs and rates, it is reasonable that MGCC values in Large IOU DF Rate Proposals, should be consistent with the rate design directives adopted by the under the Net Billing Tariff. Commission guidance for the Large IOUs to use the same MGCC values for DF Rate Proposals as are incorporated into the

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[87] D.24-02-047, Decision Adopting Preferred System Plan and Related Matters, and Addressing Two Petitions for Modification at 50.

[88] D.22-12-056 at 146.

Net Billing Tariff will ensure that DF rates are agnostic to various types of DER technologies. Accordingly, it is reasonable at this time that Large IOU DF Rate Proposals should incorporate the statewide MGCC value from the most recently adopted ACC model as of January 1, 2026, and on January 1 of every year thereafter, which is derived from IRP modeling and cost assumptions.[89]

While the Joint IOUs make a reasonable argument that there are some differences in how individual IOUs calculate energy and ancillary service revenues for determining the MGCC value for a utility-scale battery storage facility (or marginal generation resource type), allowing individual IOUs to use different MGCC methodologies could misalign MGCCs set in DF rates and the Net Billing Tariff which would send inconsistent and non-standardized long-term price signals across the three Large IOUs. However, in acknowledgement of these differences in each IOU territory, it is reasonable to provide the Large IOUs with the option to submit both the non-settled MGCC values from their most recent GRC Phase 2 applications (*i.e.* non-settled MGCC values that were calculated, submitted in testimony, and supported by workpapers) *and* the MGCC values that is an input to the ACC in their DF Rate Proposals.

4.4. Marginal Distribution Capacity Costs

An IOU's MDCCs are the costs associated with expanding or enhancing distribution infrastructure to reliably serve an incremental unit of peak demand. These costs are crucial for maintaining system reliability and accommodating growth in demand or changes in load patterns. MDCCs are typically quantified in dollars per kilowatt per year ($/kW-year). This metric reflects the annual cost

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[89] *See* 2024 Distributed Energy Resources Avoided Cost Calculator v1b and accompanying Documentation. Available at: https://www.cpuc.ca.gov/dercosteffectiveness

required to upgrade or expand the distribution network to efficiently distribute the anticipated peak load to all customers.

IOUs generally break down MDCC into two primary components: primary distribution or "peak-related" MDCC and secondary distribution or "grid-related" MDCC.

1. **Peak-Related MDCC**: Peak-Related MDCCs are associated with ensuring the distribution network can handle peak loads without compromising service quality. Peak-Related MDCCs are included in IOU rates to fund infrastructure investments that can manage the highest levels of electric demand during peak periods, prevent grid overloading, and maintain grid reliability.
2. **Grid-Related MDCC**: Grid-Related MDCCs are associated with maintaining and upgrading local distribution infrastructure closer to the customer. IOUs describe grid-related costs as encompassing broader system improvements to support consistent and efficient electricity distribution across the entire network, not just during peak times. Therefore, the IOUs tend to propose recovery of non-peak grid-related costs from customers on the basis of non-coincident demand and localized customer needs rather than system-wide coincident peak demand.

The allocation of both Peak-Related and Grid-Related MDCC components into customer rates is further differentiated based on how customers are connected to the distribution system. The portion of an IOU's MDCC that is allocated to a customer's rate depends on the customer class and service voltage level, which can be categorized into transmission-connected, primary-connected, and secondary-connected services:

1. **Transmission-Connected Services**: These customers are connected directly to the IOU's transmission network at high voltage (typically 50kV and above). Transmission-connected customers do not use the distribution system

and therefore are not allocated distribution capacity costs. These customers typically have very large industrial loads.

2. **Primary-Connected Services**: These customers are connected to the distribution network at medium voltages (typically between 4kV and 35kV). The MDCC allocated to these customers includes costs for primary distribution infrastructure such as distribution substations, circuit breakers, and primary distribution lines. Primary-connected customers avoid costs associated with secondary distribution infrastructure.
3. **Secondary-Connected Services**: These customers, including most residential and small commercial customers, connect to the secondary distribution system at low voltages (typically 120V to 480V). The MDCC allocated to these customers includes both primary and secondary distribution costs, covering the full range of distribution infrastructure from distribution substations down to local transformers, secondary lines, and service drops.

In general, customers served at higher voltage levels bear less of the distribution costs per unit of energy because they use fewer components of the distribution system. Conversely, secondary-connected customers bear the highest proportion of distribution costs per unit because they utilize more levels of the distribution system to receive their electricity service.

Because customers may receive electricity at locations on the distribution grid where distribution infrastructure capacity is lower or constrained in relation to customer load, the cost to serve these customers is relatively higher. If constrained areas of the distribution grid are located in low-income or disadvantaged communities, where cost of service is higher, this could raise concerns regarding the equity in differential pricing.

Staff MDCC Proposal

To ensure compliance with the CEC Load Management Standards requirement that DF rates include MDDCs, Staff proposes that each IOU application for DF Rate Proposals must include an MDCC that reflects the underlying marginal distribution capacity costs.[90] Staff recommends that the MDCC should be designed to recover all Peak-Related MDCC revenues for each IOU. Further, Staff recommends that:

1. The MDCC could also be designed to recover all or a portion of Grid-Related MDCC revenues;
2. The MDCC should be allowed to be differentiated by customer class and service voltage level to accurately reflect cost causation; and
3. The MDCC should be based on the utilization/congestion of a customer's local distribution network capacity.

This dynamic distribution price signal can be derived either from distribution network load forecasts or from operational data from an IOU's distribution management systems. Staff acknowledges that it may not be feasible to include circuit-specific, locational granularity in the initial design of distribution capacity price components. To address this challenge, Staff proposes that IOUs be allowed to use distribution capacity prices that reflect aggregated loads at the substation-level. Because certain substations and/or circuits might be more heavily loaded than others, resulting in higher rates when compared to an IOU's otherwise applicable tariff, this could raise concerns about unreasonable locational equity concerns. As a potential solution, Staff recommends that IOUs should calibrate the MDCC for a substation such that the

[90] Working Group Report at 42-43.

annualized revenue recovery for that substation is the same as the Otherwise Applicable Tariff.[91]

Further, Staff proposes that rate design elements that recover non-peak related Grid-Related MDCCs should not unreasonably reduce a customer's incentive to shift their energy consumption into low-price/low-emission periods. Staff also recommends that DF rates should minimize the use of non-coincident demand charges. Rate design elements such as fixed charges or load-shape subscriptions should be prioritized to the extent possible for recovery of the non-peak related marginal distribution costs.[92]

Joint IOUs MDCC Proposal

The Joint IOUs recommend initially incorporating a system-wide MDCC in DF rates. Because distribution peaks can occur at different times on different circuits, and data must still be collected to determine individual circuit needs (*i.e.*, increased capacity to serve load during periods of peak demand), the Joint IOUs suggest that a system-wide distribution signal could provide some benefit because distribution circuit peaks generally occur before those on the bulk energy system. The Joint IOUs also suggest that "(o)nly primary or costs deemed time-dependent distribution costs, as determined in each IOU's GRC (Phase 2 proceeding), should be included in distribution dynamic rates; secondary distribution costs or costs deemed non-time dependent or not coincident with the system peak are much harder to forecast, should not be included."[93] The Joint

[91] A customer's otherwise applicable tariff is the customer's default tariff that would be applicable if the customer were not enrolled in a special tariff.

[92] Working Group Report at 40.

[93] Working Group Report at 65, Table 4, Item 8.

IOUs suggest that distribution has lower capacity marginal costs, which results in a lesser price signal (in the overall DF rate).[94]

To implement more granular, location-based pricing, the Joint IOUs propose that pricing schemes should be tested in pilots on constrained circuits as it would require developing multiple forecasts and prices. The Joint IOUs caution that wide-scale implementation would require additional operational costs. As such, the Joint IOUs express concern that granular, location-based pricing may create perceived concerns about unreasonable locational equity concerns, even if prices on different circuits are the same on average. Given these factors, the Joint IOUs argue that further examination in pilots is required to better understand how dynamic load shifting will affect capacity constraints and circuit planning.[95]

Specifically, the Joint IOUs highlight that using a "circuit clustering approach," such as PG&E's clustering approach used in its Vehicle Grid Integration Pilots, should be an alternative to individual circuit-specific pricing.[96] [97] Although circuits have differing loads or locations, the Joint IOUs explain that clustered circuits have similar load characteristics (i.e., timing of high-load versus low-load hours, ramp periods, etc.) which in turn reduces the complexity associated with determining circuit-specific distribution pricing. In the Vehicle Grid Integration pilot, PG&E plans to scale the price for each circuit cluster so that every circuit collects the same average distribution capacity rate. When

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[94] Working Group Report at 77.

[95] Working Group Report at 78.

[96] PG&E V2X Pilots were approved by the Commission in Resolution E-5192 on May 5, 2022.

[97] The circuit clustering approach for PG&E's V2X Pilots was described by PG&E in AL 6694-E and approved by the Commission in Resolution E-5326 on July 11, 2024.

scaled, hourly distribution capacity prices will vary by location (depending on which cluster a particular circuit is assigned to), but all circuits will collect the same average revenue to address equity concerns.[98]

Microgrid RC MDCC Proposal

Microgrid RC has a fundamentally different approach to setting distribution capacity costs than the Joint IOUs and the Staff proposal. Microgrid RC proposes that the variable price for electricity should not include the recovery of any long-run marginal capacity costs (i.e., MGCC, MDCC, and MTCC). Instead, Microgrid RC proposes that variable prices in DF rates should only include the MEC and a Distribution Congestion Adjustment which they claim is analogous to the CAISO's transmission congestion pricing element in the CAISO wholesale market price.[99]

Microgrid RC defines the local marginal capacity cost as the price differential for electricity in constrained versus unconstrained areas, which it contends equals "the real-time cost of generation capacity that is the immediate non-wires alternative to more capacity on the transmission system."[100] Microgrid RC proposes that any further local marginal capacity cost should be captured in a Distribution Congestion Adjustment or the cost to serve customer demand that varies with the level of grid constraint that exists between a customer location and a Pricing Node. Microgrid RC's conceptual model expresses the Distribution Congestion Adjustment as the sum of Local Congestion Adjustments, or costs incurred to meet demand when substation transformers, line segments, or other distribution system equipment are congested.

[98] PG&E AL 6694-E at 11-12.

[99] Working Group Report at 142.

[100] Working Group Report at 149-150.

Rather than allocating long-term marginal capacity costs across hours based on formulas or curves as in traditional rate design, Microgrid RC proposes a real-time market-based approach. According to Microgrid RC, a market mechanism operated by a construct it calls a "Pricing Server," to manage capacity bids and offers, is required to regulate the Distribution Congestion Adjustment based on customer demand. If demand is low, then accordingly the market decreases the Distribution Congestion Adjustment, possibly to zero, to discourage electricity imports and encourage customer demand. Conversely, if demand is high, the market sets a higher Distribution Congestion Adjustment to spur local DR or electricity imports.

Microgrid RC argues that "while paying Customer Resources the Variable Energy Price is the correct economic signal for real-time system operation, such payments do not guarantee that Customer Resources will recover their full long-term cost of operation including amortizing their capital investment."[101] For this reason, Microgrid RC also suggests that customers should face differentiated capacity charges based on their historic load shapes and receive capacity payments for firm, dispatchable responses.

<u>Comments on MDCC Proposals</u>

According to Rondo Energy, excluding a MDCC element in DF rates could impact incentives for capital investments by customers, retain the same portfolio of demand-side resources, and lead to the inclusion of demand charges in DF rates that could negatively impact load flexibility.[102] Rondo Energy illustrates their views as follows:

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[101] Working Group Report at 152.

[102] Working Group Report at 86.

> Without movement away from existing flat volumetric, or non-coincident peak demand charges, the incentives for investment in capital projects which provide demand flexibility, often by increasing peak non-coincident demand during low marginal cost hours, are significantly diminished, if not destroyed. This is particularly true for existing non-coincident peak demand transmission charges, which penalize flexible loads for shifting their energy use into more consolidated time periods.[103]

VGIC recommends that, at a minimum, all DF Rate Proposals should include a dynamic distribution component. VGIC contends that distribution compensation (i.e., the load shift compensation of a dynamic distribution rate) is particularly important to managing electric vehicle (EV) charging to unlock load shifting that may substantially reduce or avoid future grid upgrades.[104] [105]

350 Bay Area argues that location-based MDCCs are required to comply with the CEC Load Management Standard requirement for DF rates to include MDCCs.[106] VGIC expresses concerns that system-wide distribution prices will not be economically efficient and will fail to meaningfully support customer investment in circuits that are most congested.[107] As such, VGIC supports PG&E's circuit clustering approach for setting distribution prices that are used in its Vehicle-to-Everything pilots.[108] SEIA recommends that IOUs should be directed to file an MDCC in their DF Rate Proposals with a locational component at the level of either planning regions and divisions or baseline territories. To

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103 Working Group Report at 86.

104 VGIC Opening Comments to Working Group Report at 8.

105 VGIC Reply Comments to Working Group Report at 3-6.

106 Working Group Report at 82.

107 VGIC Opening Comments to Working Group Report at 9-10.

108 VGIC Opening Comments to Working Group Report at 9.

support their recommendation, SEIA cites analyses from prior PG&E and SCE GRC Phase 2 proceedings, where the IOUs have geographically disaggregated their marginal distribution costs, by service territory divisions, planning regions, and/or baseline territories.[109] Clean Coalition recommends that MDCCs should be priced on a more granular basis to ensure that the distribution benefits of flexible demand where it is needed, such as in capacity constrained areas or load pockets, are captured by dynamic rates.[110]

Like the Joint IOUs, Cal Advocates recommends further examination of existing dynamic rate pilots with distribution components (*e.g.,* VCE/PG&E and SCE pilots) to better understand approaches to assign location-based MDCCs in DF rates, because in their view there is no conclusive evidence that it is feasible or cost effective to implement at this early stage.[111] Sierra Club largely agrees with Cal Advocates and suggests "an average distribution value" should be used to address equity and implementation obstacles for location-based distribution pricing.[112] CLECA agrees with the Joint IOUs that distribution marginal costs are relatively smaller and provide a weak price signal, and that a major portion of distribution costs are driven by spatial arrangements and local infrastructure requirements rather than coincident peak demand.[113]

According to EPUC, time-varying hourly volumetric prices cannot appropriately recover non-coincident capacity costs (*i.e.,* Grid-Related MDCCs) because customers "do not reduce the costs incurred by the utility to service

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[109] SEIA Opening Comments to Working Group Report at 3-5.

[110] Working Group Report at 84.

[111] Working Group Report at 83.

[112] Working Group Report at 87.

[113] Working Group Report at 84.

demand" when they shift usage to off-peak periods.[114] Instead, EPUC supports the use of non-coincident demand charges that mirror EPMC-scaled long-run, marginal non-peak distribution capacity costs to recover local distribution costs.[115] EPUC maintains that properly structured demand charges should provide a cost-based means for collecting revenues while sending efficient price signals to customers that support grid optimization.[116]

Guidance on MDCCs

After evaluating each proposal, party comments, and the CEC Load Management Standards, we agree with 350 Bay Area that Section 1623(a)(1) requires that DF Rate Proposals must include an hourly MDCC component. While we acknowledge the perspectives of Cal Advocates and Sierra Club to initially include only a system-wide dynamic distribution price in DF Rate Proposals, we agree with the Staff Proposal that a location-based distribution price should be included in DF Rate Proposals. This pricing design is needed to reflect the time-dependent nature of local distribution costs that are based on the degree of distribution capacity constraint. Therefore, it is reasonable to require that initially Large IOU DF Rate Proposals should include an MDCC that is location-based and appropriately recovers the costs that vary with customer class and voltage level. Ensuring that distribution prices reflect local distribution congestion network conditions is crucial to enabling the type of load shift response and efficient distribution utilization that has the potential to reduce long-term distribution upgrade costs, as asserted by 350 Bay Area, Rondo Energy VGIC, SEIA, and Clean Coalition.

[114] Working Group Report at 158.

[115] Working Group Report at 158.

[116] Working Group Report at 157-158.

As such, we reject the Joint IOUs' recommendation that initial MDCCs in DF Rate Proposals should be based solely on system-wide grid conditions because they will not provide adequate geographic specificity to achieve the type of load flexibility that measures and allocates costs for local congestion and potentially reduce future distribution upgrade costs. However, we do recognize that operational complexities, addressing equity concerns, and the need for additional data collection and analysis may prevent the Joint IOUs from initially implementing highly granular circuit-specific distribution pricing. We therefore recommend Staff's proposal for IOUs to either use (1) aggregate loads at the substation-level or (2) PG&E's circuit-clustering approach referenced in the Joint IOU proposal, which calibrates prices to recover the same annual revenues as customers' Otherwise Applicable Tariff, to set MDCCs. Both options serve as potential pathways toward more granular methods to address fairness and equity in distribution pricing.[117]

Both Staff and Joint IOU proposals recommend consistent average annual prices across the distribution system while allowing for time-varying price differentials that reflect local conditions. In aggregate, the total annual revenue collected across each IOU's service territory will still recover the MDCC revenue requirement. To preserve parity in pricing, it is reasonable to require that initial IOU DF Rate Proposals should include an MDCC that is location-based and appropriately recovers the costs that vary with customer class and voltage level.

We reject Microgrid RC's Distribution Congestion Adjustment proposal because it is based solely on a customer's location on the distribution system and could result in significantly different annual revenue recovery (or annual $/kWh

[117] Described in both Staff and Joint IOUs proposals and in PG&E AL 6694-E at 11-12.

rate) and bill impacts for customers; and may not be feasible to implement as highlighted by the Joint IOUs,[118] CLECA,[119] and Cal Advocates.[120]

We agree with the Staff Proposal and Rondo Energy that rates with flat volumetric charges and large non-coincident demand charges can significantly diminish load-shifting incentives for customers. However, we also see merit in arguments made by EPUC and CLECA that non-coincident demand charges recover distribution capacity costs that are not peak-dependent in a cost-based manner. Therefore, it is reasonable to require Large IOUs to limit non-coincident demand charges in DF Rate Proposals to only recover demonstrably customer-specific non-peak distribution costs that are clearly shown to be caused by individual customer non-coincident demand rather than system or circuit peak loads. Large IOUs must justify any inclusion of non-coincident demand charges in their DF Rate Proposals by showing how they align with Commission Rate Design and DF Design principles and the CEC Load Management Standards, particularly principles regarding cost causation and system reliability, while providing quantitative analysis demonstrating they will not unreasonably reduce a customer's potential for load flexibility. This analysis should include a comparison of the expected load-shifting incentives with and without the proposed non-coincident demand charges.

4.5. Marginal Transmission Capacity Costs

An IOU’s Marginal Transmission Capacity Costs, or MTCC represents the annualized cost per kilowatt to upgrade or expand transmission infrastructure to reliably transport an incremental unit of electricity, especially during peak

[118] Working Group Report at 158.

[119] Working Group Report at 157.

[120] Working Group Report at 156.

demand periods. MTCC is typically measured in dollars per kilowatt per year ($/kW-year) and reflects the annualized investment required for augmenting the transmission system to deliver the highest forecasted loads to distribution networks without failure or significant losses.

IOUs generally break down MTCC into two components: peak-related and grid-related costs, similar to the MDCC. The MTCC values are typically determined as part of a Transmission Owner Rate Case filed at the Federal Energy Regulatory Commission (FERC). The corresponding transmission capacity revenue requirement is calculated by applying the MTCC ($/kW-year) to the system peak load (kW). Separately, IOUs may file an application at FERC to address time-differentiated transmission rates pursuant to its FERC Transmission Owner tariff.[121]

Staff MTCC Proposal

Staff encourages IOUs to apply for an hourly marginal-cost based transmission rate in the next Transmission Owner rate case filed at the FERC to meet CEC Load Management Standard deadlines for a compliant marginal-cost based hourly rate.[122] Further, Staff recommends that IOUs apply a similar rate design approach for transmission capacity prices as they do for generation capacity prices, where the hourly price is a function of transmission system utilization.[123]

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[121] Working Group Report at 81-82.

[122] Working Group Report at 43.

[123] Working Group Report at 6.

As an example, Staff cites PG&E's time differentiated TOU study, which presents an illustrative cost-based TOU transmission rate.[124] Staff suggests that the same costs identified in this study could be used to create an hourly transmission capacity price component rather than just TOU periods, reflecting hourly variations in transmission system utilization.[125]

Joint IOUs MTCC Proposal

The Joint IOUs propose that TOU transmission rates should be incorporated in DF rates as a first step, which would promote load management by enhancing on-peak versus off-peak rate differentials. However, the Joint IOUs caution that it is not yet clear how hourly dynamic transmission rates would impact price differentials during periods of peak generation, and whether these would enhance or possibly counteract the generation price signal.

To address this uncertainty, the Joint IOUs suggest that a detailed study should be conducted before implementing hourly dynamic transmission pricing. They note that PG&E, SCE, and SDG&E are in the process of examining the merit of proposing time-differentiated retail transmission rates prior to filing an application at FERC. The Joint IOUs also suggest that it may be valuable to first observe how customer load shifting in response to dynamic generation prices benefits the transmission system, even without the addition of a specific transmission price signal. [126]

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[124] PG&E 2020 GRC Phase 2 Transmission Time-of-Use Rate Study Report, November 18, 2022, A.19-11-019.

[125] Working Group Report at 43.

[126] Working Group Report at 80-81.

<u>Microgrid RC MTCC Proposal</u>

Microgrid RC proposes that the CAISO wholesale price at Pricing Nodes already includes the short-run marginal cost of both energy and transmission. Specifically, Microgrid RC notes that transmission constraints in CAISO's network are reflected in the congestion component of locational marginal prices, which represents transmission marginal costs. Microgrid RC explains that when transmission into an area is constrained, higher-priced local generation resources must be called upon to meet demand in that area. This congestion pricing in the wholesale market already captures the short-run value of transmission capacity. According to Microgrid RC, the higher price paid for electricity from local generation resources in these constrained areas represents the avoided cost for transmission capacity, and therefore no additional transmission capacity price component is necessary.[127]

<u>Comments on MTCC Proposals</u>

Support for Additional Studies Before Implementation

350 Bay Area points out that 23% of energy service costs are related to T&D marginal costs, and new transmission costs now exceed average new generation contract costs per megawatt hour (MWh) of delivered electricity, which is an upward trend that they anticipate will continue.[128] As such, 350 Bay Area advocates for "fully capturing the value" of marginal transmission costs in DF Rate Proposals to support accurate and effective price signals. 350 Bay Area's suggestion that DF Rate Proposals should include volumetric transmission rates

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[127] Working Group Report at 149.

[128] Working Group Report at 156.

for small to medium customers, based on FERC-authorized costs, appears to align with Staff's proposal on this issue.[129] [130]

To expedite the inclusion of MTCCs in DF rates, Sierra Club recommends that the IOUs should propose TOU-based transmission rates at FERC and include them in DF rates as soon as possible.[131] UCAN and Rondo Energy both agree.[132] While several parties express a sense of urgency, Cal Advocates and CLECA concur with the Joint IOUs that additional studies are required to reveal costs and determine the correct price signals in transmission rates.[133] [134]

Sierra Club and Clean Coalition similarly observe that Microgrid RC's proposal does not explicitly include transmission pricing in its proposal, which may not comply with the CEC Load Management Standard Tariff requirements. [135] [136] CLECA questions whether Microgrid RC's congestion-based approach addresses the allocation of transmission costs beyond just those reflected in CAISO market prices, noting that other issues in hourly allocation of transmission costs are not addressed.[137]

<u>Guidance on MTCCs</u>

Pursuant to CCR Section 1623 (a), Large IOUs must submit marginal cost-based rates to the Commission for approval that include marginal generation,

[129] Working Group Report at 13.

[130] Working Group Report at 82.

[131] Working Group Report at 16.

[132] Working Group Report at 86 and 104.

[133] Working Group Report at 83.

[134] Working Group Report at 85.

[135] Working Group Report at 157.

[136] Working Group Report. at 158-159.

[137] Working Group Report at 171.

distribution, and transmission rates that vary on a time interval of no longer than one hour. Given this requirement, we agree with 350 Bay Area that the CEC Load Management Standard necessitates the development of hourly transmission capacity price components to be included as a component of DF Rate Proposals.[138] Therefore, it is reasonable to require that the Large IOUs include an hourly transmission capacity price component in DF Rate Proposals. While the Sierra Club, Rondo Energy, Clean Coalition, and UCAN note the importance of expediting TOU-based transmission capacity pricing for DF rates, TOU-based rates may not comply with the CEC Load Management Standard requirement that each marginal cost component should be priced on an hourly basis. We also acknowledge the Joint IOUs', Cal Advocates', and CLECA's position that additional studies are needed to determine appropriate hourly and TOU transmission capacity price signals and therefore encourage the IOUs to undertake the necessary studies to propose rate designs for time-varying transmission capacity prices.

Accordingly, we provide the following guidance to the Large IOUs on MTCC design: Large IOUs are encouraged to meet and confer to develop a plan to design MTCC price components that complement MGCC and MDCC price components that will be included in DF Rate Proposals. We direct the Large IOUs to describe their plan to design MTCC price components that will be incorporated in DF Rate Proposals, either in supplemental testimony in existing applications, or in any new applications. For example, PG&E presented findings from its time-differentiated TOU rate study to Working Group 1 on June 9, 2023, with an illustrative rate design approach that identified certain transmission

[138] Cal. Code Regs. tit. 20 § 1623.

capacity costs with a cost basis for being time-differentiated. While the costs identified in this study were used to create a time-differentiated rate structure, the same methodology could be applied to develop hourly transmission capacity prices that reflect the utilization of the transmission system.[139]

4.6. Non-Marginal Costs

The marginal cost of service ratemaking methodology has historically been the principal basis for revenue allocation and rate design among California's Large IOUs. In their GRC Phase 2 applications, IOUs calculate their marginal cost components and the resulting marginal cost revenues (i.e., the total revenues they would collect if electricity were priced exclusively at those marginal costs). The difference between an IOU's total authorized revenues and its marginal cost revenues are referred to as "non-marginal" or "residual" costs.

The IOUs define "non-marginal costs" as those costs not directly tied to incremental usage-based drivers, including but not limited to the costs of wildfire mitigation and vegetation management, reliability improvements, safety and risk management of the distribution system, ongoing distribution operations and maintenance, regulatory balancing accounts, and various programs and policy mandates.[140] Non-marginal costs also include costs associated with an IOU's contracts for generation, distribution, and transmission resources that are incremental to the IOU's most recently determined marginal costs. While some non-marginal costs may be fixed (*i.e.,* not vary with the amount of energy consumed by individual customers) the Commission found insufficient record in the Track A decision to determine which portion of an IOU's non-marginal costs

[139] Working Group Report at 43.

[140] D.24-05-028 at 69.

are fixed.[141] Instead, the Commission identified other specific categories of IOU costs as fixed, and therefore appropriate to be recovered through income-graduated fixed charges.

To reconcile marginal cost revenues with an IOU's GRC Phase 1 authorized revenue requirements, the Commission has traditionally adopted the Equal Percentage of Marginal Cost, or EPMC methodology. According to the EPMC methodology, multipliers are developed to scale generation and distribution marginal cost revenues to collect all required non-marginal revenues and allocate a percentage of these revenues to each customer class.

In rate design specifically, the EPMC methodology applies these same multipliers to scale specific marginal cost rate components (*e.g.*, customer charges, energy charges, and demand charges) to recover each customer class's allocated share of non-marginal costs. Rates set in this manner have been typically termed as "cost-based rates" and have been affirmed as the Commission's favored starting point for both revenue allocation and rate design.[142]

Non-marginal costs have routinely been used to incentivize customer behavior and support specific policy outcomes. SCE currently applies EPMC scaling to its marginal costs to derive many of its TOU rates.[143] The Commission has rejected the contention that time-varying volumetric rates should only reflect marginal costs as assessed in a GRC Phase 2 proceeding.[144] In 2018, the Commission affirmed the importance of scaling time-dependent marginal costs

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[141] D.24-05-028 at 69.

[142] D.18-08-013 at 12-20.

[143] Working Group Report at 85.

[144] D.18-08-013 at 54.

according to the EPMC methodology to achieve revenue neutrality and stated the following:

> [Failure] to scale time-dependent marginal costs in peak energy charges and peak demand charges shifts costs to other rate components, in particular off-peak energy charges and non-coincident demand charges. Customers appropriately shifting usage to off-peak hours would therefore pay more for PG&E's service than they should given the costs to serve them. This is the true cost shift that we seek to avoid through rates with appropriately scaled ratios between peak and off-peak energy prices.[145]

Staff Proposal for Non-Marginal Costs

Staff recommends that non-marginal costs should be collected in DF rates by scaling marginal costs according to the EPMC methodology to ensure revenue neutrality.[146] To support this, Staff cites Commission approval of SCE's AL 4684-E-A pursuant to D.21-12-015, where SCE described its approach for scaling marginal costs to collect non-marginal to attain revenue neutrality through its dynamic capacity price design for its dynamic rate pilot:

> Revenue neutrality for the dynamic price portion of the customer's bill is achieved by scaling the raw marginal cost curves by the Equal Percent Marginal Cost (EPMC) scalar for each revenue component from SCE's GRC (Phase 1).[147]

Staff emphasizes that non-marginal costs not recovered through dynamic volumetric prices (*i.e.* MECs, MGCCs, and MDCCs) need to be recovered using alternate rate design elements. Accordingly, Staff recommends requiring IOU DF Rate Proposals to clearly identify how rate components (such as subscriptions,

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[145] D.18-08-013 at 54.

[146] Working Group Report at 7.

[147] SCE AL 4684-E-A, "Supplemental to Tier 2 Advice Letter for SCE's Dynamic Rate Pilot Pursuant to D.21-12-015," at 3.

fixed charges, or different types of adders) will be used to recover any residual non-marginal costs.[148] Further, Staff recommends that DF Rate Proposals provide a detailed accounting of non-marginal costs, explaining their evolution over time, and for proposals to identify long-term cost drivers for non-marginal costs. Lastly, Staff recommends requiring any IOU opting to use a non-time-differentiated (or "flat") Revenue Neutral Adder to collect non-marginal costs, instead of a time differentiated Revenue Neutral Adder or EPMC scalars, to include a comprehensive analysis of the long-term revenue impacts and the potential cost shifts of the approach.[149]

Joint IOUs Proposal for Non-Marginal Costs

The Joint IOUs oppose using the EPMC method to collect non-marginal costs because they argue it results in higher overall system and customer costs. The Joint IOUs also argue that "artificial" increases in marginal cost during high-cost hours can lead to overpayment for customers with load flexibility that shift load to low-cost hours, while customers that do not have load flexibility would be exposed to higher marginal costs and prices.[150]

The Joint IOUs also assert that scaling marginal costs to recover non-marginal costs should not be permitted for exports as this will lead to over-compensation for self-generation and result in a revenue shortfall, leading to cost shifts to other customers which Joint IOUs consider to be economically inefficient.[151] Alternatively, if a customer is enrolled on a two-part, subscription-

[148] Working Group Report at 40.

[149] Working Group Report at 40.

[150] Working Group Report at 82.

[151] Opening Comments of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company in Response to Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5 at 3-4.

based rate design (*i.e.,* rates that include a customer load-shape subscription that is billed at an Otherwise Applicable Tariff rate), the Joint IOUs claim that the customer's hourly load profile would accurately track that its entire electric load and only unscaled marginal costs need be reflected in the real-time price signal.[152] However, if the subscription is inaccurate or customers can subscribe to a usage level below their historic load profile, the Joint IOUs suggest that a Revenue Neutral Adder must be included in DF rates to collect non-marginal costs. In such scenarios, the Joint IOUs claim that a Revenue Neutral Adder is needed to achieve parity with the Otherwise Applicable Tariff because the subscription will cover only a portion of the difference between marginal costs and revenue requirement. The Joint IOUs contend this offers a simple solution to address revenue shortfalls and cost shifts to other customers that cannot shift load.[153]

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[152] Customer load-shape subscriptions are a customer bill management option through which customers are pre-allocated an hourly usage profile (based on their historic hourly usage) and are pre-billed for their "subscribed" quantity at a non-dynamic (*e.g.* TOU) rate. Only the difference between a customer's subscribed quantity and the actual usage in a given hour is billed (or credited) at the dynamic rate. Rates that include subscriptions are called "Two-part Tariffs". Further discussion of subscriptions is provided in the Customer Options section below.

[153] Working Group Report at 81-82.

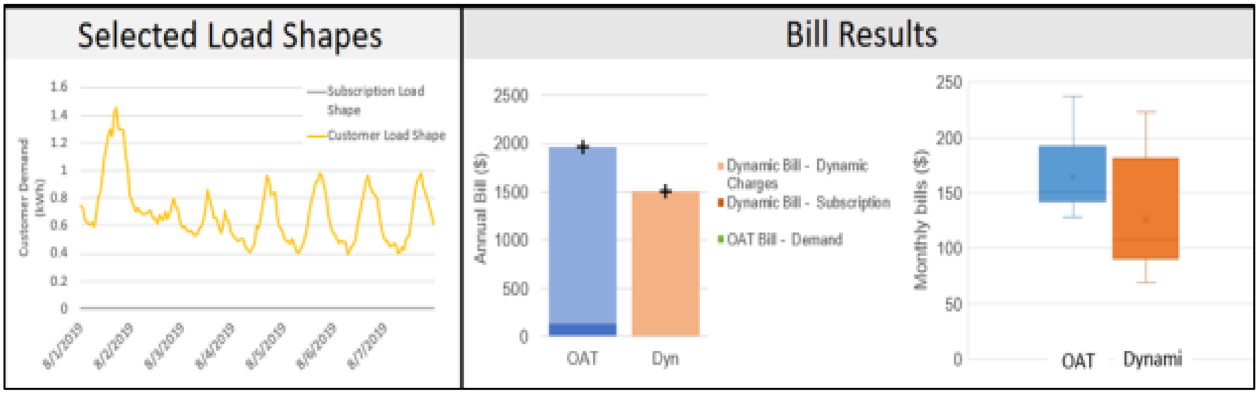

Figure 1: This scenario illustrates the bill impacts in the absence of a subscription (an extreme case of subscription mismatch), where the customer is billed based on their exact monthly usage. In this situation, the customer is charged according to the dynamic hourly rate for their entire usage. When the dynamic prices are not scaled to be revenue neutral, the mismatch in revenue recovery between a revenue-neutral Otherwise Applicable Tariff rate and a dynamic rate can be exacerbated. The final bill amount can vary from the standard Otherwise Applicable Tariff bill due to structural impacts (such as revenue neutral prices) arising from the contrast between the dynamic hourly rate and the Otherwise Applicable Tariff.[154]

Microgrid RC Proposal for Non-Marginal Costs

Microgrid RC does not explicitly address EPMC scaling of marginal costs to collect non-marginal costs in DF rates in its proposal. Microgrid RC's proposed Variable Energy Price includes the wholesale market price and a distribution capacity adder but does not recover marginal capacity costs. Instead, Microgrid RC proposes that DF rate customers should be assigned an "Option" based on their historical usage profiles to ensure appropriate revenue recovery for each customer.[155] [156]

[154] Working Group report at 21-22. The bill results in this figure were generated using the Dynamic Pricing Bill Calculator Tool, which was prepared by Lawrence Berkeley National Laboratory (LBNL) and made available to all the Working Group parties. The LBNL Dynamic Pricing Bill Calculator Tool compares the inelastic bill impacts of various customer types/classes with a variety of options for both the components of the dynamic rate and types of subscriptions.

[155] Working Group Report at 159-164.

[156] Microgrid RC's Option is an alternative to a subscription-based DF tariff. Under this scheme, the DF customer is entitled but not obligated to purchase up to the Customer Profile level (or historical load profile) at the Legacy Price (which is a Base Price plus an averaged energy charge expressed as a per kWh price). When a customer's actual electricity use for an hour is less than or equal to electricity use based on the Customer Profile level, the customer pays the Legacy

<u>Comments on Non-Marginal Costs</u>

This section will provide an overview of comments on party proposals to collect non-marginal costs through either application of an EPMC scalar to marginal costs or a Revenue Neutral Adder.

SEIA, CLECA, Rondo Energy, and TeMix support the scaling of marginal cost prices to recover the full associated revenue requirement, including non-marginal costs, for each cost component. CLECA claims that shifting the difference between an IOU's marginal cost revenues and the embedded cost revenue requirement to low-cost hours decreases the effectiveness of price signals for load shifting. To this point, CLECA notes that the Commission has applied an EPMC scalar to collect non-marginal costs in most rates for many years, as it directed PG&E in D.18-08-013 to enable rates to better reflect cost of service.[157] As a compromise, CLECA suggests that scaling marginal costs to collect non-marginal costs could be weighted across different hours (*i.e.,* the difference between the embedded revenue requirement and the marginal cost revenues is divided by the total loads), as in PG&E's Extended Pilot.[158] For example, peak hours could have a lower weighting factor (*e.g*. less than 1) or scalar in comparison to the weighting factor for off-peak and super off-peak (*e.g.* greater than 1). [159]

Price. When a customer's actual electricity use for an hour is more than above the Customer Profile level, the customer pays the Variable Price (including the Base Price and the Variable Energy Price). If the Customer does not use its entire Customer Profile amount in a time interval, the customer pays only the Legacy Price for the customer's actual usage and is paid the Variable Energy Price for the customer's reduction. (*See* Working Group Report at 159.)

[157] Working Group Report at 85.

[158] Working Group Report at 84.

[159] Working Group Report at 85.

Rondo Energy supports Staff's recommendation to use an EPMC scalar to recover non-marginal costs, emphasizing that it promotes customer usage behavior that supports the State's climate goals.[160] TeMix argues that failing to use a scalar to collect non-marginal costs can lead to an overbuild of generation, distribution, and transmission capacity leading to inefficient investment in energy efficiency and flexible devices and cost increases.[161] [162] SBUA similarly supports scaled marginal costs for both imports and exports to promote more economically efficient use of electricity.[163]

SEIA also favors using the EPMC scalar and cites D.18-08-013, where the Commission explicitly rejected PG&E's argument that application of EPMC scaling to time-dependent marginal costs would result in cost-shifting.[164] Further, SEIA recommends scaling marginal costs in both import and export prices, reasoning that:

> a customer who shifts a kW of load out of the peak period has the same impact on the utility system during the peak period as a customer who exports a kW of generation to the grid in the peak period. In both cases, the upstream loads on the utility are reduced by a kW. As a result, it makes sense to send the same prices signal for both imports and exports.[165]

Conversely, the Joint IOUs claim it can be more cost based to collect non-marginal costs using a flat Revenue Neutral Adder rather than a

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[160] Working Group Report at 46.

[161] Working Group Report at 31.

[162] Working Group Report at 31.

[163] Working Group Report at 6-7.

[164] D.18-08-013 at 54 and COL 32.

[165] SEIA Opening Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 11.

time-differentiated one or EPMC scalar. To that end, the Joint IOUs argue that the Revenue Neutral Adder cost-shift analysis recommended by Staff is unnecessary. The IOUs argue they should be allowed to retain the flexibility to use a flat or TOU-based Revenue Neutral Adder, depending on each IOU's design policies and methodologies.[166] VCE, Polaris, and Gridtractor support the Joint IOUs' recommendation to use a time-differentiated Revenue Neutral Adder.[167] Cal Advocates warns that using a multiplier to scale marginal costs overcompensates customer exports that potentially causes a negative contribution to margin so that revenues no longer sufficiently recover the marginal cost of service.[168]

Sierra Club favors using a Revenue Neutral Adder because in their view (1) scaling marginal costs disadvantages customers that cannot shift load and (2) applying multipliers to distribution prices in areas of high solar generation, where feedback to the grid may occur, risks creating excessively high prices when solar output is abundant. According to Sierra Club, raising costs during these hours undermines California's GHG reduction goals and penalizes customers seeking to use cleaner energy.[169]

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[166] Working Group Report at 45.

[167] Working Group Report at 47.

[168] Cal Advocates' Opening Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 11.

[169] Sierra Club Opening Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 at 1-3.

Guidance on Non-Marginal Costs

We agree with CLECA,[170] [171] SEIA,[172] Rondo Energy[173] and TeMix,[174] that the EPMC scalar should be used to scale marginal capacity prices to recover their allocated portion of the IOU's total authorized revenue requirement (i.e., their allocated portion of "non-marginal" costs) in import DF rates.

To ensure that rates better reflect cost of service, we also acknowledge CLECA's reference to the Commission's prior direction to IOUs to develop TOU rates with full EPMC scalars in D.18-08-013. To this point, all three IOUs routinely use EPMC scaling of marginal cost rate components for demand charges, and SCE uses EPMC scaling for most of its TOU rate designs. As noted by the Joint IOUs, there is a potential for mismatch in revenue recovery between unscaled marginal cost dynamic rates and Otherwise Applicable Tariffs even if customer options, such as two-part tariffs, are part of the rate design for DF Rate Proposals. Accordingly, we continue to affirm the Commission's recent conclusions and therefore reject the argument that the application of EPMC scaling to time-dependent marginal capacity prices *for import DF rates* results in cost-shifting.[175] We also agree with SEIA, Rondo Energy, and TeMix that DF Rate Proposals should not inhibit or disincentivize customers from using energy

[170] Working Group Report at 85.

[171] CLECA Opening Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 3.

[172] SEIA Opening Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 Ruling at 14-15 & SEIA Reply Comments to Ruling 2-8.

[173] Working Group Report at 46.

[174] Working Group Report at 31.

[175] D.18-08-013 at 54.

during low-price/low-emission periods by applying a flat or non-time-differentiated Revenue Neutral Adder to time-dependent marginal costs.

While we acknowledge CLECA and the Joint IOUs' arguments that a non-time dependent adder to collect non-marginal costs could achieve revenue-neutral prices, such an approach would significantly mute the desired price signals and thus incentives that support the goals of DF rates. In other words, applying a flat adder uniformly across all time periods would dilute the cost differential between high and low-price periods, reducing customers' economic incentive to shift load, which would be incompatible with our rate design and DF principles. We therefore reject the Joint IOUs' recommendation to allow the use of a flat Revenue Neutral Adder to recover non-marginal costs. Furthermore, we adopt guidance that if the IOUs choose to employ a Revenue Neutral Adder to collect non-marginal costs, a time-differentiated Revenue Neutral Adder is required. We remain concerned that use of any rate design with a Revenue Neutral Adder to collect non-marginal costs in import rates has the potential to mute the price signal for customers to shift load and support grid reliability and reduce greenhouse gas emissions.

Consistent with the Commission's rate design and DF principles, our objective in this decision is to establish cost recovery mechanisms that carefully balance the need to maximize economic efficiency and potential customer savings while avoiding adverse structural rate impacts. Applying an EPMC scalar to marginal capacity prices to collect non-marginal costs has been a long-standing Commission-approved rate design practice employed in numerous rate designs for all three IOUs.[176] The Commission has previously directed the

[176] D.17-09-035 at 20.

development of import rates with full EPMC scalars, finding them to better reflect cost of service. Therefore, it is reasonable to require that in DF Rate Proposals, marginal capacity prices for import rates should be scaled to recover the EPMC allocated portion of each IOU's total authorized revenue requirement (i.e., the EPMC allocated portion of "non-marginal" costs).

Nevertheless, it is reasonable to provide the IOUs with two options for recovering non-marginal costs in import DF Rate Proposals: (1) using an EPMC scalar applied to time-varying marginal capacity prices, or (2) using a time-differentiated Revenue Neutral Adder. Both approaches are designed to maintain time-differentiated signals that encourage load shifting, though an EPMC scalar is likely to more effectively preserve the relative price differentials between time periods. IOUs that select a time-differentiated Revenue Neutral Adder to collect non-marginal costs must provide testimony, workpapers, and analysis in their DF Rate Proposals that provide a side-by-side comparison for its use in lieu of an EPMC scalar (*e.g.* a more conversative and simple approach to collect non-marginal costs that customers may understand).

While Microgrid RC did not explicitly address EPMC scaling of marginal costs in its proposal, Microgrid RC's proposed variable energy price, which only includes the wholesale market price and a Distribution Congestion Adder, will not allow for recovery of either the marginal capacity revenue requirement or of the allocated portion of the IOU's total authorized revenue requirement (i.e., the non-marginal costs that would normally be recovered through EPMC scaling). For this reason, we reject Microgrid RC's proposal because systematic undercollection of costs is not an acceptable outcome.

Based on a review of the record, it is reasonable to direct each of the Large IOUs to provide a detailed accounting of the elements comprising their proposed non-marginal generation costs, describe how revenues associated with those costs have evolved over time, and identify the long-term cost-drivers of non-marginal generation costs in their DF Rate Proposals. In addition, it is also reasonable to require that the Large IOUs include in their DF Rate Proposals approaches to recover revenue categories that are not already addressed through the scaling of time-varying rate components (*e.g.,* marginal customer access costs, non-peak marginal distribution capacity costs, other non-marginal costs) through alternate rate design elements to ensure that DF rates are revenue neutral. DF Rate Proposals that recover costs through non-volumetric rate elements (*e.g.,* fixed charges, non-coincident demand charges, customer load-shape subscriptions) should include an analysis of how these elements might affect a customer's incentive to shift load to low-cost and/or low-emission hours.

4.7. Marginal Cost Updates

This section will provide an overview of the Joint IOUs' proposed method to update marginal costs, a review of party comments, and our guidance on this issue.

The Joint IOUs' assert that maintaining 2020 marginal costs, which are significantly out of date, will not send a strong enough price signal to customers enrolled in DF rate pilots. Further, the Joint IOUs highlight that their distribution upgrade costs have also increased, as significant investments in wildfire hardening procedures and vegetation management have been required to assure system safety and reliability. According to the Joint IOUs, increasing the dynamic capacity components of their RTP rates to reflect current marginal costs will not affect average rates but will give customers a larger opportunity to reduce their bills when they shift load in response to RTP prices.[177]

In Advice Letter (AL) 7243-E, PG&E proposes to update its MGCC and MDCC and the corresponding revenue recovery targets for its RTP pilot rates only, in proportion to its revenue requirement changes since May 1, 2020, adjusted for sales changes.[178] PG&E notes that its marginal costs also have increased significantly since 2020. For example, system resource adequacy values, or 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.[179] PG&E also notes that capital costs for grid-scale batteries also increased significantly, as reflected by inputs and assumptions for the utilities' respective IRP Preferred System Plans.[180]

PG&E's methodology to update MGCCs and MDCCs, which are used to calibrate the revenue recovery for the dynamic capacity price components for its RTP pilot rates, is the product of the (1) MGCC or MDCC adopted in the 2020 GRC Phase 2 and (2) the ratio of (a) the May 1, 2020 bundled average generation or distribution rate and (b) the current bundled average generation rate or distribution rate which is expressed as follows:

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[177] PG&E AL 7243-E at 2-3.

[178] PG&E AL 7243-E, Updating Marginal Cost Signals for All Real-Time PG&E Pricing Pilots and Rates, was approved effective May 19, 2024. Available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7243-E.pdf.

[179] PG&E AL 7243-E at 2-3.

[180] 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.

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

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

PG&E proposes to apply this scaling relationship to adjust its RTP pilot dynamic rates until the Commission updates its marginal costs in response to its 2023 GRC Phase 2 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.

Comments on Marginal Cost Updates

The Joint IOUs support the use of escalation scalars proposed in PG&E AL 7243-E to update MGCCs and MDCCs in each year following the determination of marginal costs in GRC Phase 2 proceedings. To determine these escalation scalars, the Joint IOUs propose that each IOU should conduct a marginal cost study in their respective GRC Phase 2 proceedings. Further, the Joint IOUs suggest that IOUs should have the option to request Commission approval to use the escalation methodology via submission of Tier 1 ALs.[181] If escalated MGCCs and MDCCs are not reasonably close to actual attrition year costs, the Joint IOUs propose that each IOU could submit Tier 2 ALs that propose an alternate methodology supported by a rationale.[182] EPUC agrees, but further

181 Joint IOU Opening Comments to April 24, 2024, ALJ Ruling at 1-3.

182 Joint IOU Opening Comments to April 24, 2024, ALJ Ruling at 1-3.

argues that MDCC updates should only reflect the demand component of the distribution rate rather than changes in average generation rates.[183]

CLECA recommends that the IOUs use an average rate adjustment based on the respective percentage change in generation or distribution revenue requirement to all generation or distribution components of the hourly dynamic rate.[184] CLECA reasons that this approach resembles the current practice for rate adjustments based on the percentage change in system average rates. CLECA also suggests that applying a scalar to adjust long-run marginal costs is preferable to adjustment of short-run marginal costs which can be volatile due to fluctuations in capacity. Further, CLECA recommends Commission approval via a Tier 2 AL process to enable stakeholder review.[185]

Cal Advocates believes that PG&E's proposed methodology to update MGCCs is needed to reflect costs that promote economically efficient use of electricity and supports Commission approval through a Tier 2 AL process to enable stakeholder review.[186] [187] However, Cal Advocates recommends that MGCC updates should not be required in years when underlying revenue requirements or costs do not increase or change substantially thereby providing

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[183] EPUC Reply Comments on ALJ's Ruling Track B Working Group 1 Proposals and Issue 5 at 2.

[184] EPUC Opening Comments to April 24, 2024, ALJ Ruling at 2-4.

[185] CLECA Opening Comments to April 24, 2024, ALJ Ruling at 3-4.

[186] Cal Advocates Opening Comments on April 24, 2024, ALJ Ruling at 3-6.

[187] Cal Advocates Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 6.

that rates are cost-based.[188] Cal Advocates further suggests that marginal distribution cost updates should only apply to the Peak-Related MDCC, or time-dependent component of DF rates, because this value is influenced by customer demand.[189] Cal Advocates recommends that Peak-Related MDCC updates should occur through studies rather use of a scalar that can inadvertently affect fixed charge-related components that should not vary with customer demand.[190]

SEIA opposes PG&E's proposed methodology to update MGCCs without modification because it does not align with how MGCCs have often been determined through settlements in GRC Phase 2 proceedings and could lead to parallel or repeated litigation of marginal costs for a single IOU in multiple regulatory venues.[191] Alternatively, SEIA supports utilizing existing IRP and ACC marginal cost update cycles to ensure that dynamic rate tariffs will provide accurate marginal cost-based compensation for exports.[192] SEIA points out that the statewide MGCC utilized in the ACC model, is directly derived from IRP cost and modelling assumptions and is updated every two years as part of the IRP and ACC update cycles.[193]

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[114] Cal Advocates Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 3-4.

[189] Cal Advocates Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 7.

[190] Cal Advocates Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 8.

[191] SEIA Reply Comments to April 24, 2024, ALJ Ruling at 1-2.

[192] SEIA Opening Comments to April 24, 2024, ALJ Ruling at 9-10.

[193] SEIA Opening Comments to April 24, 2024, ALJ Ruling at 5-6.

If SEIA's proposal is not adopted, SEIA suggests that PG&E's marginal cost update methodology should be filed via a separate Tier 3 AL to allow for appropriate review.[194] SEIA refutes Cal Advocates' claim that alleged fixed costs in MDCCs, such as wildfire mitigation costs, are not marginal because distribution upgrades will be needed to address new requirements for fire safety and reliability.[195] The Joint IOUs disagree with SEIA's proposal because they contend that the IRP does not consider IOU forecasted energy costs, flexible capacity costs, and loading factors that apply to capital additions to develop inputs to MGCCs.[196]

CalCCA does not support or oppose annual MGCC or MDCC updates but strongly recommends that IOUs and CCAs should be required to update MGCC values simultaneously to preserve customer indifference. To that end, CalCCA recommends that CCAs work with IOUs to reset CCA MGCC updates prior to seeking Commission approval of IOU MGCC updates in AL filings that are subject to stakeholder review.[197] In a similar vein, SBUA recommends that the Commission should adopt a process that allows parties to provide comments

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[194] SEIA Opening Comments to April 24, 2024, ALJ Ruling at 11.

[195] SEIA Opening Comments to April 24, 2024, ALJ Ruling at 12-13.

[196] Reply Comments of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company in Response to Administrative Law Judge's Ruling on Track B Working Group 1 Proposal at 6-7.

[197] CalCCA's Comments on Administrative Law Judge's Ruling Track B Working Group 1 Proposals and Issue 5 Track B Working Group 1 Proposals and Issue 5 at 3-4.

and recommendations for MGCC updates prior to the issuance of Advice Letters by the IOUs.[198] [199]

Guidance for Marginal Cost Updates

We agree with the position held by most parties that the MGCC price component should be calibrated annually to recover all long-run MGCCs. Accordingly, it is reasonable to require each Large IOU to file a joint AL that proposes the annual MGCC update for DF rates using one of the following two options:

1. The first option is based on the MGCC value that is an input to the ACC. The Large IOUs shall file a joint Tier 2 AL by March 31, 2026 and by March 31 every year thereafter that proposes use of the annual MGCC value from the most recently adopted ACC for a particular year, as of January 1 of that year. This ensures that the MGCC values are up-to-date and reflect a Commission-approved, standardized valuation of the long-run cost of marginal generation capacity.
2. The second option is based on the MGCC update process described by PG&E in advice letter 7243-E, which scales *calculated* MGCCs, that were either proposed or settled in the most recent GRC Phase 2 proceeding. If opting to use this approach, the Large IOUs shall submit any proposed annual MGCC updates in a joint Tier 2 AL by March 31, 2026 and by March 31 every year thereafter. This approach, as illustrated in PG&E advice letter 7243-E, helps maintain accurate price signals by adjusting the MGCC proportionally to changes in overall generation costs.

[198] Small Business Utility Advocates Opening Comments on the April 24th Ruling Regarding Track B Working Group 1, Issue 5 at 4.

[199] Small Business Utility Advocates Opening Comments on the April 24th Ruling Regarding Track B Working Group 1, Issue 5 at 2.

Based on potential fluctuations in costs in attrition years, it is reasonable for MDCCs to be adjusted on an annual basis. It is also reasonable for the Joint IOUs to conduct a marginal distribution cost study in GRC Phase 2 proceedings resulting in MDDCs and escalation scalars that are adopted by the Commission.

However, we do agree with Cal Advocates that annual updates to MDCCs should only occur when there is evidence that distribution capacity costs have actually changed. If evidence does not support that distribution capacity costs have escalated significantly from one year to the next, then applying a methodology as proposed by PG&E in AL 7243-E, to increase MDCCs is not justified. As raised by EPUC and CLECA, only changes in demand-related revenue requirements should be used to justify updates to MDCCs. Therefore, it is reasonable that each Large IOU must file a Tier 2 advice letter by March 31 in a year when MDCC updates are warranted. This AL must include data and analysis demonstrating whether distribution capacity costs have changed significantly, and if so, how the proposed adjustments reflect those changes.

4.8. Day-Of-Market Pilots

To support system reliability in real-time, Track B Working Group 1 considered whether additional dynamic rate pilots with day-of pricing would be beneficial as a near-term solution. Given the potential for grid conditions to change rapidly, some stakeholders proposed that DF Rate Proposals could incorporate real-time day-of wholesale market prices from CAISO's 15-Minute Market or CAISO's 5-minute Real-Time Market. The Commission could use these pilots to identify whether future DF Rate Proposals with real-time day-of market prices may benefit customers through enhanced demand flexibility and utilities through avoided investment in commodity and infrastructure capacity.

Day-of-Market Pilot Proposals

To accurately reflect real-time grid congestion, where energy commodity costs, and generation, distribution, and transmission capacity costs are reduced by flexible demand; Staff recommends that DF Rate Proposals should identify customer classes that would benefit from participating in CAISO's 15-Minute Market or CAISO's 5-Minute Real-Time Market. To achieve this, Staff recommends that DF Rate Proposals should include a pilot proposal for classes that wish to participate in these markets.[200]

The Joint IOUs suggest that LSEs should be encouraged to issue 15-Minute Market or 5-Minute Real-Time Market proposals after the RTP landscape has matured.[201] Before initiating 15-Minute Market or 5-Minute Real-Time Market pilots, the Joint IOUs suggest that the Commission should find that there is sufficient interest from targeted customer classes, based on evidence provided by the LSEs, to justify the expense of running these pilots.[202]

Comments on Day-of-Market Pilots

Rondo Energy argues that 15-Minute Market or 5-Minute Real-Time Market pilot programs, which are inherently limited in duration, will not provide the rate certainty that is needed to incentivize investment in large-capacity, load flexible technologies and the integration cost associated with the complexity of day-of markets.[203] EPUC contends that 15-Minute Market or

[200] Working Group Report at 13.

[201] Working Group Report at 75-76.

[202] Working Group Report at 76.

[203] Working Group Report at 16.

5-Minute Real-Time Market pilots may not be cost-effective if customer interest and participation is low.[204]

Guidance on Day-Of-Market Pilots

We agree with Rondo Energy that establishing and implementing day-of-market pilots may not provide the certainty needed to incentivize investments from large customers that can effectively participate. Per EPUC's concern, we do not find sufficient evidence in the record that a day-of market pilot would be cost-efficient for ratepayers, especially for small customers that may not be able to invest in technologies that enable their participation. Therefore, we will not require that the Large IOUs offer day-of-market prices in their initial DF Rate Proposals. However, we do encourage the Large IOUs to revisit offering day-of-market prices as an option in DF Rate Proposals at a later time, *e.g.,* after IOUs have clearly identified which customers can respond to day-of prices and provide additional ratepayer value by responding to those prices.

5. Export Rates and Export Compensation

This section considers how export rate components in DF rates should be structured to ensure alignment with the Commission's Demand Flexibility Design Principle 6, adopted in D.23-04-040, that forms the basis for the design of export compensation:[205]

> "Demand flexibility tariffs should provide marginal cost-based compensation for exports to enable economically efficient grid integration of customer-sited electrification technologies and distributed energy resources."

Given the Commission's recognition that export rates and export compensation involves careful consideration of multiple stakeholder interests,

[204] Working Group Report at 119.

[205] D.24-04-040 at 33.

including customers with export-capable resources, non-participating ratepayers, and broader grid reliability and economic objectives, any approach to export compensation must balance its potential cost and benefit implications for all ratepayers.

Staff Export Compensation Proposal

Staff recommends that all DF Rate Proposals should include a price-based, non-discriminatory (*i.e.,* technology-agonistic) approach to designing export rates for eligible BTM customer resources. To enable simple, scalable optimization of individual device schedules for DERs, Staff proposes that DF Rate Proposals should have both import and export rates, or symmetric bidirectional rates. To ensure transparency, Staff recommends that IOUs should clearly specify which cost components are included or excluded from both the dynamic import and export rate in their DF Rate Proposals. If DF Rate Proposals feature asymmetric rates (i.e., a different rate for imports than for exports), Staff recommends that IOUs should provide a detailed explanation of how these prices would impact the scheduling of customer DER exports. [206]

Joint IOUs Export Compensation Proposal

Initially, the Joint IOUs recommend that export compensation should be based on export rates that include (1) marginal energy costs and marginal generation capacity costs, with the potential addition of marginal distribution costs and marginal transmission costs pending the development of methodologies and a determination of their impact on the price signal and (2) exclude non-marginal costs (i.e., fixed costs or sunk costs) to ensure that DF rates are equitable and avoid cost shifts.[207]

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[206] Working Group Report at 29.

[207] Working Group Report at 95.

Microgrid RC Export Compensation Proposal

Microgrid RC proposes that its Variable Energy Price, which includes only the real-time CAISO wholesale price and a Distribution Congestion Adjustment, should be uniformly applied to both import and export rates.[208] As such, Microgrid RC's export compensation does not include any long-run marginal capacity costs in the export price.[209] Instead, Microgrid RC suggests that customers should receive capacity payments when they agree to provide a firm, dispatchable response in particular circumstances or for a particular number of hours."[210]

Comments on Export Compensation Proposals

The Joint IOUs reiterate that the export rate should only include marginal energy costs and marginal generation capacity costs (*i.e.,* asymmetric) as determined in each IOU's GRC Phase 2 proceeding, and potentially include transmission and primary distribution marginal costs, pending the development of a rate design methodology.[211] The Joint IOUs also state if an export compensation methodology is developed for transmission and primary distribution marginal costs, that these components can also be evaluated for whether they would send the right signal in the export rate. Further, the Joint IOUs assert that "Non-NEM, non-QF export compensation may raise questions about the boundary between retail and wholesale jurisdiction, which should be considered in the appropriate venue."[212]

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[208] Working Group Report at 142-143.

[209] Working Group Report at 165.

[210] Working Group Report at 6.

[211] Working Group Report at 95.

[212] Working Group Report at 95.

Cal Advocates agrees with the Joint IOUs that export rates should be based only on marginal costs, and that inclusion of non-marginal costs could result in overcompensation to customers with DERs leading to cost shifts.[213] Further, the Joint IOUs disagree with Microgrid RC's proposal to exclude all long-run capacity costs from the export price.[214]

Conversely, some parties, including VCE, Polaris Energy Services, and Gridtractor,[215] Sierra Club,[216] TeMix,[217] SBUA[218] broadly support symmetric bidirectional pricing because it allows for easy scheduling and optimization of customer exports. Polaris Energy Services, and Gridtractor, express the concern that asymmetric export pricing may add costs and complexity for customer systems.[219] TeMix argues that scaling of marginal costs to recover non-marginal costs through a bidirectional, symmetric price is required because scarcity or marginal-cost based pricing recovers only the approved total cost during high load periods, and recovers fewer fixed costs during low load periods.[220] SEIA supports symmetric pricing because a "customer who shifts a kW of load out of the peak period has the same impact on the utility system during the peak period as a customer who exports a kW of generation to the grid in the peak period".[221]

213 Working Group Report at 95.

214 Working Group Report at 165.

215 Working Group Report at 31.

216 Working Group Report at 96.

217 Working Group Report at 30-31.

218 Working Group Report at 30.

219 Working Group Report at 97.

220 Working Group Report at 30-31.

221 SEIA Opening Comments on Administrative Law Judge Ruling on Track B at 14.

CLECA argues that bidirectional, symmetric pricing is acceptable only if it is cost-based and therefore recommends that the price elements should only be limited to the CAISO wholesale price, and additional generation capacity costs. CLECA states that as coincident demand is established as a cost driver for transmission and distribution capacity costs, those additional price components could be added to the export rate.[222]

350 Bay Area, Sierra Club, and Clean Coalition support reflecting avoided T&D capacity costs in export compensation. 350 Bay Area argues that because local T&D capacity needs are addressed by local resources, especially when local capacity is constrained, then export compensation must credit any location-specific value for delivering energy close to load.[223] Sierra Club supports pilot-testing the inclusion of local RA costs in all time-varying rates (including TOU, Critical Peak Pricing, and DF rates) to identify the benefits of local capacity resources and determine location-specific pricing for distribution rates below the system level (*i.e.* substation or circuit-level) after considering any equity concerns.[224] Clean Coalition claims that Microgrid RC's proposal to solely compensate exports for energy value and not the capacity value ignores the locational benefits of exports that may be dependent on where the electricity originates.[225] Clean Coalition also contends that Microgrid RC’s proposal does not consider that exports from the distribution grid reduce the need for imports

[222] Working Group Report at 96.

[223] Working Group Report at 95.

[224] Working Group Report at 96.

[225] Working Group Report at 96.

from the transmission system, and therefore should merit compensation for avoided Transmission Access Charges.[226]

Guidance on Export Compensation

The Commission declines to provide guidance on whether the Large IOUs should include export compensation in DF Rate Proposals in this decision.

However, if a Large IOU elects to include export compensation in a DF Rate Proposal, then the DF Rate Proposal should use asymmetric pricing, where export rates are based solely on unscaled marginal costs, while import rates include a scalar or a time-differentiated Revenue Neutral Adder to recover the EPMC-scaled portion of an IOU's authorized revenue requirement. As noted by Cal Advocates and the Joint IOUs, export prices that incorporate non-marginal costs would lead to cost shifts to non-participating customers. Non-marginal costs in all rates are collected to fund essential utility infrastructure investments and programs, including but not limited to: wildfire mitigation and vegetation management, reliability improvements, safety and risk management of the distribution system, ongoing distribution operations and maintenance, and various policy mandates that benefit all ratepayers. However, customer exports do not provide these essential benefits to all ratepayers. The asymmetric approach avoids cost shifting and ensures revenue neutrality, cost-reflectivity and strong load-shift economic incentives in a manner that aligns with past Commission precedent.

6. Customer Protection Options

In this section, we will consider protection options to help customers plan and manage the dynamic portion of their bills, including customer load shape

[226] Working Group Report at 157.

subscriptions, forward transactions, and bill protections. Initially, we will examine customer protection options proposed by Staff, the Joint IOUs, and Microgrid RC that are intended to incentivize demand flexibility and maintain bill neutrality for DF rate customers. After a review of party comments on these proposals, we will then identify viable customer solutions for IOUs to include in their DF Rate Proposals.

6.1. Staff Customer Protection Proposal

Two-Part Subscription Tariffs

Staff proposes that IOU applications should include proposals for two-part tariffs with customer load-shape subscriptions.[227] The two-part tariff includes the following components:

1. A subscription tariff where each customer is provided a customer-specific hourly load profile for each month, where the subscription portion of the bill is estimated based on the customer's historic Otherwise Applicable Tariff and historic energy use. By "pre-purchasing" an hourly load profile for each customer at the Otherwise Applicable Tariff rate, the subscription provides monthly bill protection against extended periods (i.e., multi-day to multi-week) of high hourly prices. The subscription portion of the total bill also recovers an appropriate share of a utility's embedded or non-marginal costs from each customer.
2. A dynamic tariff which reflects the hourly marginal cost of electricity, but may not include all embedded costs that is used to:

[227] According to Staff's two-part tariff proposal, (t)he customer's subscription load shape is billed at the customer's legacy rate or Otherwise Applicable Tariff (inclusive of all demand and customer charges). All hourly usage that differs from the customer's subscribed load shape is billed at the dynamic volumetric rate. The customer's total bill is the sum of both the subscription and the dynamic parts of the tariff." Working Group Report at 18.

a. Credit customers when their actual energy used is less than their subscribed quantity in a particular hour, or

b. Bill customers when their electric usage exceeds their subscribed quantity in a particular hour.

According to Staff, each subscription tariff should closely mirror each customer's historical usage. From a cost-recovery perspective, Staff suggests that each two-part tariff that features this subscription option is likely to be close to revenue-neutral because most customer load would be billed at the business-as-usual Otherwise Applicable Tariff. The dynamic tariff in this two-part tariff option would still incentivize customers' load shift-behavior.[228]

Two-part subscription tariffs include a customer subscription option based on the customer's load shape from the previous year or averaged over multiple years. Staff highlights that LBNL's dynamic pricing bill impacts study[229] and LBNL's subscription design tool show that two-part subscription tariffs minimize structural impacts on customer bills and utility revenue recovery, while incentivizing customer load-shift behavior.[230] [231] Staff emphasizes that the subscription should be designed to serve several purposes (particularly for small energy users) that includes (1) providing partial bill protection against sustained periods of high energy market prices, (2) recovering appropriate embedded costs

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[228] Working Group Report at 17-24.

[229] Gerke, Brian F., Marius Stübs, Samanvitha Murthy, Aditya Khandekar, Peter Cappers, Richard E. Brown, and Mary Ann Piette. "Potential bill impacts of dynamic electricity pricing on California utility customers." Lawrence Berkeley National Laboratory (2022) at 47.

[230] During the Working Group process, a tool developed by the LBNL assisted in the design and evaluation of customer load-shape subscriptions. LBNL's tool (1) calculates customer subscriptions based on historical usage data and provides a mechanism for simulating the financial impact on both customers and utilities and (2) evaluates various subscription design options to help stakeholders understand the trade-off involved in different types of subscription designs.

[231] Working Group Report at 18.

fairly, and (3) ensuring that incentives for price-responsive load shift on a daily basis are not impacted.[232] In further support of their proposal, Staff also provides dynamic pricing examples from two large utilities, Georgia Power Company and Oklahoma Gas and Electric Company, that offer dynamic pricing at scale for more than 30 years and require two-part subscription tariffs for their dynamic pricing rates.[233]

Staff proposes that the subscriptions should be class-specific, so that large and small energy users are differentiated as follows:

<u>Large Energy Users (High Load Factor Customers):</u> [234]

- Staff proposes that the subscription methodology for Large Energy Users such as industrial and large commercial customers should align with the two-part tariff approach of utilities like Georgia Power or Oklahoma Gas and Electric.[235] These customers would be enrolled on static monthly subscription tariffs based on their historic monthly usage averaged over the past three years. The shape and quantity of a customer's subscription would remain static unless changed by mutual agreement between the customer and the utility.
- The methodology for the subscription tariff should ensure appropriate embedded or non-marginal cost recovery based on historic usage and not change year-to-year without mutual agreement. The purchase price for the subscription tariff may be calculated as the customer's Otherwise Applicable Tariff ($/kWh) multiplied by their

[232] Working Group Report at 20.

[233] Working Group Report at 19.

[234] Typically, customers with electric demand above 200 kW are categorized as large energy users and have high load factors or a high efficiency of electricity usage.

[235] Georgia Power's Dynamic Rate is an "(h)ourly rate where customers are billed for "baseline" use at an Otherwise Applicable Tariff and pay (or receive credits) for energy used above (or below) the baseline each hour at the RTP rate". Working Group Report, Appendix 2 at 507 and Energy Division California Flexible Unified Signal for Energy (CalFUSE) White Paper at 93.

subscribed hourly load shape (kWh), though IOUs may propose alternative methodologies for calculating this price that appropriately recover embedded costs. If certain embedded costs are not recovered by the dynamic price, the customer's subscription may include recovery of those costs, either as a fixed charge or a volumetric charge based on the subscription quantity. Importantly, Staff proposes that all demand charges should apply only to the subscription portion of a customer's usage, ensuring that price responsiveness is based solely on the dynamic volumetric price.[236]

***Small Energy Users (Low Load Factor Customers)*: [237]**

- For small energy users such as residential, agricultural, and small commercial customers, Staff proposes that the subscription methodology could be simplified by using cluster-specific or class-specific usage patterns.[238] The load shape in a simplified subscription-based rate could correspond to TOU periods (*e.g.,* 3-point subscriptions with set energy quantity ratios between super-off-peak, mid-peak, and on-peak pricing periods). Staff offers several options for determining the subscription quantity for small customers, which can be challenging to predict due to the more variable usage patterns of smaller customers: [239]
  1. Ex-ante baseline subscriptions that can be set to equal the Tier 1 usage allowance for each climate zone;
  2. Ex-post subscriptions or "pay for your load shape," that allow for the quantity of energy in a customer's subscription to be scaled on a look-back basis and therefore match the customer's actual usage; and

[236] Working Group Report at 19-20.

[237] Typically, customers with electric demand below 200 kW are categorized are small energy users and have low load factors or a low efficiency of electricity usage.

[238] Clustering or clustering analysis groups energy users based on common energy use patterns.

[239] Staff provides a detailed description for each of type of subscription option in the Working Group Report at 19-23.

3. Price-adjustments where the average of the dynamic price is adjusted with a scalar offset to recover the same revenues as a class-specific tariff. (referred to as PG&E/VCE's price adjustment proposal in the Working Group report).

Transactive Pricing Program

In addition to customer subscriptions, Staff recommends that IOUs should offer an optional Transactive Pricing Program to customer classes that can schedule their loads ahead of time. When enrolled in the Transactive Pricing Program, customers can purchase or sell quantities of energy on a forward basis (*e.g.,* week-ahead) according to a forecasted price.[240] This would enable customers to optimize and pre-schedule their energy use to provide demand flexibility.

6.2. Joint IOUs Customer Protection Options Proposal

The Joint IOUs propose to test various rate and bill management options in a pilot to promote customer acceptance and maintain load shift incentives, identify strategies to mitigate bill volatility, and address revenue over or under collection and potential cost shifts.[241]

Two-Part Subscription Tariffs

Like Staff, the Joint IOUs suggest that IOUs could offer customers a two-part tariff that includes a subscription rate based on the Otherwise Applicable Tariff and a dynamic rate that charges or credits customers for any deviation in customer's energy use from their predetermined load profile. The Joint IOUs list several ways that the two-part subscription rate can be designed

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[240] The Transactive Pricing Program for PG&E's Expanded Pilot #1 for agricultural customers was authorized by D.24-01-032.

[241] Working Group Report at 87.

to (1) reflect a customer's historical load in a prior month or year (2) incorporate a customer subscription, such as those used by Georgia Power or Oklahoma Gas & Electric, that is negotiated with the customer and represents less than 100% of a customer's historical load to incent load shifting, and (3) account for weather effects that may affect prices. Further, the Joint IOUs suggest that LSEs that offer these rates should determine how often the subscription will be updated (*e.g.*, seasonally or annually) and assert that any demand charges should be based on subscription load.

Due to their complexity, the Joint IOUs observe that two-part subscription rates may be difficult for customers to understand, and therefore any customer protection that is offered should be balanced against this concern.[242]

<u>Price Adjustment Proposal</u>

The Joint IOUs also suggest that VCE's price adjustment proposal may be considered. In this pricing scheme, dynamic prices are scaled on a daily basis, retrospectively or prospectively, so that the load-weighted average of dynamic price equals the load-weighted average of the Otherwise Applicable Tariff price. According to the Joint IOUs, implementation of dynamic price adjustments would not require billing system updates.[243]

However, the Joint IOUs highlight a few issues that may be of concern regarding price adjustments: First, downward adjustment of dynamic prices during peak demand periods may result in negative dynamic prices in an effort to maintain bill neutrality. According to the Joint IOUs, such downward adjustments could lead to grid stress because customers would not be

[242] Working Group Report at 88-89.

[243] Working Group Report at 89.

incentivized to shift load during periods of grid stress.[244] Second, due to variations in customers' load factors, a load-weighted Otherwise Applicable Tariff price based on historical usage may need to be offered that could introduce difficulties for implementation and messaging.[245]

Forward Transactions

The Joint IOUs also propose that forward transactions could be offered on a week-ahead basis to specific customer classes (e.g. large commercial or agricultural customers). According to the Joint IOUs, the forward transaction would shift revenue collection risk from customers to load serving entities, including the IOUs. To address this, the Joint IOUs suggest including a risk premium in the forward transaction pricing scheme that recovers costs from ratepayers and examining any impacts related to revenue overcollection or undercollection. To ensure that transactive rates are acceptable at FERC, the Joint IOUs recommend that additional research is required to determine if and how grid exports may impact the regulatory boundary between wholesale/retail exports. The Joint IOUs note that forward transactions would be easier for customers to understand but would be equally difficult to implement. As such, the Joint IOUs recommend piloting forward transactions with large customers before a wider rollout to other customers, noting that these rates are unlikely to attract small customers in the near term.[246]

Bill Protection

The Joint IOUs also consider bill protection as a safeguard against bill volatility (*i.e.* guaranteeing that a customer does not have bills that exceed those

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[244] Working Group Report at 89.

[245] Working Group Report at 89.

[246] Working Group Report at 90.

based on a customer's Otherwise Applicable Tariff). Prior to offering bill protection to customers, the Joint IOUs suggest that the need and effectiveness of such protection should be evaluated in pilots. In particular, the Joint IOUs point out that bill protection may not be cost-effective, as witnessed during SCE's rollout of residential TOU rates, and that permanent bill protection could remove the dynamic rate price signal and lead to cost shifting.[247] To address these concerns, the Joint IOUs suggest that "bill limiters" could be offered to guarantee that bills from DF rates would not exceed a certain percentage of bills based on a customer's Otherwise Applicable Tariff.[248]

6.3. Microgrid RC Customer Protection Options Proposal

As a customer protection method, Microgrid RC proposes that DF rate customers may exercise an option to purchase electricity (Option) up to a Customer Profile level, based on historical energy use and load shape, at the Legacy Price. Microgrid RC explains its proposal as follows:[249]

1. At the Customer Profile level, the customer pays the Legacy Price;
2. Above the Customer Profile level, the customer pays the Variable Price; and
3. Below the Customer Profile level, the customer pays the Legacy Price for their actual usage and are compensated for the Variable Energy Price for any reduction in usage.

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[247] Working Group Report at 91. The Joint IOUs note that "(i)n the case of the TOU rollout for residential customers, it was SCE's second largest program expense for the rollout, costing ratepayers over $35M dollars, although very few customers were aware of bill protection, and only 14% of customers surveyed felt it was valuable."

[248] Working Group Report at 91.

[249] Working Group Report at 159.

Microgrid RC offers several methods to develop Customer Profiles such as using (1) a three-year average (2) yearly or quarterly energy consumption, to account for seasonal variability or (3) at a level that is below historical customer usage to incentivize energy conservation.[250]

Because the annual Option load shape aligns with the annual calculation of marginal capacity costs, Microgrid RC claims it would not dilute or exaggerate RTP signals. Further, Microgrid RC suggests that any partial reallocation of capacity costs attributed to use of the Option load shape should be uniformly distributed across utility service territories and therefore not vary in reference to areas of local distribution congestion.[251]

6.4. Comments on Customer Protection Proposals

The following section provides an overview of party comments on customer protection options from Staff, the Joint IOUs, and Microgrid RC.

General Comments on Customer Protection Options

Several parties recommend the use of pilots to examine customer protection methods. The Joint IOUs propose exploring the merit of different customer protections, including two-part tariffs with subscriptions in pilots but point out that they are complex and not readily understandable by customers. VCE, Polaris Energy Services, Gridtractor, CalCCA, and CLECA agree. [252]

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[250] Working Group Report at 160.

[251] Working Group Report at 160.

[252] Working Group Report at 27-28. Working Group Report at 92-94. Note that in the "price-adjustment" approach, as implemented in the VCE AgFIT pilot, a constant scalar is added to the dynamic price so that the weekly average of the dynamic price is the same as the average Otherwise Applicable Tariff price over. This ensures that the relative difference between a low-price hour and a high-price hour is maintained but adjusts the seasonal average of the price to the same as the Otherwise Applicable Tariff.

TeMix and Cal Advocates both agree with the Joint IOUs that the details of two-part subscription tariffs should be resolved in pilots prior to implementation.[253] [254] Cal Advocates points out that existing IOU DF pilots have made significant methodological changes to address customer understandability of two-part tariffs with subscriptions. Further, Cal Advocates suggest that all customer protection options should be studied in pilots to address cost shifts, customer enrollment and participation, and use of ratepayer funds in pilots.[255]

CLECA suggests that a variety of customer protection options may be needed to attract different types of customers and cautions against relying on them to recover embedded cost revenues which in their view should be recovered in the dynamic rate itself or through fixed charges.[256]

To determine the appropriate generation bill protection method for each CCA, CalCCA favors continued testing of these methods in pilots, such as the price-adjustment procedure that is currently being examined in the VCE/PG&E AgFIT dynamic rate pilot.[257]

Comments on Two-Part Subscription Tariffs

Several parties provided general commentary on the use of two-part subscription rates or tariffs. CalCCA does not support or oppose two-part subscription tariffs but suggest that their application to specific customer classes and use cases must be considered in the design. Clean Coalition states that Staff's two-part subscription tariff proposal could require customers to pay for the

[253] Working Group Report at 31.

[254] Working Group Report at 24.

[255] Working Group Report at 92.

[256] Working Group Report at 92.

[257] Working Group Report at 93.

entire subscription amount regardless of energy usage and disincentivize energy conservation.[258] Microgrid RC argues that Staff's two-part subscription tariff acts as a fixed charge because the customer is required to pay a subscription charge regardless of energy use, which it asserts violates cost causation principles.[259]

Several parties commented on the usefulness of two-part subscription tariffs for large versus small customers.[260] SBUA contends that two-part subscription tariffs are more apt for large customers and recommends a simplified approach for small customers. CLECA agrees. Further, CLECA suggests that large customers, in particular, should have the option to modify their subscription level down to zero because they can manage usage and price volatility.[261] [262]

Rondo Energy points out that large energy users are not necessarily high-load factor customers (*i.e.,* industrial heat use with a thermal battery system that have a capacity of 100 MW and a 20-25% load factor). Given this, Rondo Energy suggests that dynamic load should not be considered in subscription design. Rondo Energy also recommends that demand charges should not apply to the non-subscription portion of a customer's bill to ensure price responsiveness based only on dynamic volumetric prices.[263] In reference to small customers, CforAT highlights that Staff's two-part subscription tariff proposal does not require historic customer-specific usage for larger households, medical

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[258] Working Group Report at 27.

[259] Working Group Report at 159.

[260] Working Group Report at 26.

[261] Working Group Report at 26.

[262] Working Group Report at 28.

[263] Working Group Report at 27.

usage customers, or customers with inelastic demand. Further, CforAT suggests that low-income households, which are more likely to move frequently and have varying number of people per account, could face challenges in developing appropriate load-shape subscriptions, and consequently risk high bill volatility.[264]

Comments on Transactive Pricing and Forward Transactions

While some parties conditionally support Staff's Transactive Pricing proposal, others raise concerns about its initial feasibility and value.

The Joint IOUs support Transactive Pricing but only for specific customer classes. As with other customer protection options, the Joint IOUs support testing Transactive Pricing in pilots because it may not be cost-effective due to its complexity. [265]

Cal Advocates points to a lack of clarity on how Transactive Pricing will be implemented and whether it will be cost-effective. [266] VGIC suggests that Transactive Pricing should be eventually offered to all customer classes, arguing that smaller customers should have access to the forward contract market to reduce bill volatility.[267] VGIC and Leap Frog Power both recommend that the Commission should provide guidance to IOUs to include forward transaction proposals in their DF Rate Proposals.[268] [269] CLECA, however, opposes offering forward transactions for longer than one or two weeks due to forecasting risks

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[264] Working Group Report at 26.

[265] Working Group Report at 25.

[266] Working Group Report at 25.

[267] VGIC Opening Comments on December 22, 2023 Report at 3-4.

[268] VGIC Opening Comments on December 22, 2023, at 3-4.

[269] Leap Frog Power Opening Comments on December 21, 2023, at 3-4.

unless it is demonstrated that collected revenue is similar to Otherwise Applicable Tariff revenues for the one or two week period in question.[270]

Comments on Bill Protection, Bill Limiters and other Customer Protection Options

350 Bay Area supports the Joint IOUs' bill limiter proposal because it may be more understandable to consumers than Staff's two-part subscription tariff. 350 Bay Area also supports Microgrid RC's Option because it would provide bill protection during the initial adoption phase for DF rates and may be more readily understandable to customers.[271] [272] Because it is unclear how a two-part subscription tariff will be implemented, communicated, and managed by various systems, VCE, Polaris Energy Services, and Gridtractor imply that bill protection may be a better customer protection solution.[273] SBUA suggests that a simple bill limiter without a transactive pricing option could be offered to residential and small commercial customers, while a two-part subscription tariff could be offered to large customers who can actively manage their electricity costs.[274]

CforAT asserts that the Joint IOU proposal needs more details on potential bill protection options, particularly regarding third-party management of customer bills. CforAT cautions that offering several bill protection mechanisms alongside complex rate designs may confuse customers. CforAT also highlights the Joint IOUs' concerns about potential self-selection bias, where customers who can easily shift load could disproportionately enroll in DF rates, potentially

[270] Working Group Report at 26.

[271] Working Group Report at 24.

[272] Working Group Report at 92.

[273] Working Group Report at 28.

[274] Working Group Report at 28.

leading to revenue undercollection and creating challenges if programs are expanded more broadly.[275]

Comments on Microgrid RC's Option Proposal

Several parties support Microgrid RC's Option proposal. Compared to the two-part subscription tariff, 350 Bay Area notes that the Option proposal would provide greater customer planning and management capabilities and reduce the risk of subscribing to and paying for more energy than needed,[276] and may provide better energy conservation incentives.[277] Clean Coalition and Sierra Club both favor the Option because customers would only be charged for energy usage.[278] [279] Further, SBUA points to the ability of customers enrolled on the Option to purchase energy up to the upper limit based on their historic load shape according to their Legacy Rate.[280]

Conversely, the Joint IOUs strongly oppose the Option because in their view setting hourly prices based on a customer's hourly load that is either above or below their Option level makes it challenging for automation controllers to forecast the hourly price, which complicates the optimization of customer devices. Due to the uncertainty in forecasted prices, the Joint IOUs claim that customer understanding of Option prices is impaired and further affects the ability of the IOUs to determine if revenue neutrality would be maintained.

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[275] Working Group Report at 93.

[276] Working Group Report at 24.

[277] Working Group Report at 161.

[278] Working Group Report at 161.

[279] Working Group Report at 163.

[280] Working Group Report at 163.

Like the Joint IOUs, CLECA asserts that because the Option would be exclusively used for fixed cost recovery, and would be based on a customer's historic usage, it would not account for customers with significant year-to-year changes in usage, which will lead to undercollection of revenues that would be exacerbated under future load growth scenarios.[281] CforAT also notes that the Option does not account for changes in customer location and household composition that affect load shape or demand, which in its view makes it a poor fit for low-income households.[282]

6.5. Evaluation of Customer Protection Options in DF Rates

The following section describes the Commission's assessment of customer protection options in relation to customer needs, feasibility of implementation, and the stability of revenue recovery.

Need for Customer Protection Options

While dynamic rates may provide significant energy efficiency and grid reliability benefits, they also may increase bill volatility. During peak pricing events, customers may face unexpectedly high bills that can create economic strain and financial uncertainty. While the overall structure of these DF rates would allow a customer to potentially reduce bills through load shifting during peak pricing hours throughout the year, bill volatility that can occur due to prolonged high-price events (*e.g.,* multi-day high price events) is an issue that must be addressed through customer protection options.

[281] Working Group Report at 161.

[282] Working Group Report at 161-162.

Further, revenue recovery is a crucial consideration when adopting widespread dynamic rates. If the rates are not carefully designed, utilities may need to increase rates to recover any structural revenue shortfalls.

Therefore, it is reasonable for Large IOUs to provide customer protection options in their DF Rate Proposals for bill and revenue stability that can enable wider adoption of hourly DF rates without creating large structural bill impacts (*e.g.,* where customer bill impacts are due to the structural differences between a hourly dynamic rate and a static, or non-hourly dynamic rate [*i.e.,* TOU rate] rather than due to a customer's load shifting performance in response to the dynamic price) for both participants and non-participants.

While a wide range of parties, including the Joint IOUs, Cal Advocates, CalCCA, CLECA, VCE, Polaris Energy Services, Gridtractor, and TeMix voice their support for testing various customer protection options in pilots prior to being offered in IOU DF Rate Proposals, we note that some customer options including the two-part subscription tariff and transactive pricing are currently being offered and tested in existing DF pilots, including the PG&E/VCE AgFIT pilot. Further, as discussed in the Section 6 of this decision regarding equity and access to DF rates, we provide guidance to the Large IOUs on measures to consider and address the needs of disadvantaged and low-income communities when designing DF rates, including but not limited to customer protection options.

<u>Assessment of Customer Protection Approaches</u>

Based on our review of the record, two-part subscription tariffs may provide an effective balance of customer protection, revenue recovery stability and preservation of price signals. Subscription tariffs, as proposed by Staff and the Joint IOUs, offer the advantage of maintaining full incentives for load shifting while providing bill stability. They enable customers to pay a fixed amount based on their historical usage patterns, while any usage above or below this subscription amount is billed at the dynamic price, providing a clear incentive for customers to optimize their energy use. Two-part subscription tariffs can be an effective measure for IOUs to recover the appropriate share of total revenues while maintaining the integrity of cost-based pricing for DF rates.

We acknowledge that a wide range of parties, including 350 Bay Area, VCE, Polaris Energy Services, Gridtractor and SBUA, contend that bill limiters and bill protection as proposed by the Joint IOU, are simpler customer protection options that are more understandable for smaller and less sophisticated customers.[283] However, as evidenced by the Joint IOUs' experience with TOU bill protection, which cost SCE ratepayers over $35M while providing limited perceived value to customers, bill limiters may undermine customers' incentives to respond to dynamic prices and may have the potential to shift costs to non-participants depending on how they are implemented.[284]

It is also reasonable to conclude that there are other alternatives to two-part subscriptions tariffs, such as VCE’s price-adjustment methodology, which may provide a better balance between customer understandability and customer protection for small and medium class customers. However, we do acknowledge

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283 Bill limiters set a maximum cap on the total electric bill, either in each month or on an annual basis, ensuring that it does not exceed a certain percentage above the amount the customer would have to pay if their bills were based on their Otherwise Applicable Tariff. Bill protection is a stricter form of a bill limiter where the customer’s bill does not exceed the amount the customer would have to pay if their bill were based on their Otherwise Applicable Tariff.

284 In the Working Group Report at 91, the Joint IOUs state that bill protection has been used several times in the past for pilots or rollouts, with mixed results. In the case of the TOU rollout for residential customers, it was SCE’s second largest program expense for the rollout, costing ratepayers over $35M dollars, although very few customers were aware of bill protection, and only 14% of customers surveyed felt it was valuable.

the Joint IOUs' concern that implementing the price-adjustment methodology, which requires including a load-weighted Otherwise Applicable Tariff price in DF rates, may be difficult to implement and explain to potential customers.

Addressing Concerns Regarding Two-Part Subscription Tariffs

Counter to the claim from 350 Bay Area and Clean Coalition, we conclude that two-part subscription tariffs can provide customers with incentives to reduce energy. The dynamic component provides clear price signals to shift or reduce load. The Staff proposal also includes the option to scale subscriptions on an ex-post basis, which would ensure that the subscription quantity in a billing period matches the customer's actual usage. The Joint IOUs similarly note that subscriptions can be designed to be less than 100% of a customer's historic load to incent load shifting. This is similar to Staff's suggestion to use the baseline allowance for each climate zone as the basis for subscription quantities.

Further, we also do not agree with Microgrid RC, Clean Coalition, and 350 Bay Area that customers might pay for energy they do not use when enrolled on two-part subscription tariffs. The Staff proposal includes the option to scale two-part subscription tariffs on an ex-post basis, which we believe would ensure that the subscription quantity in a billing period matches the customer's actual usage. Consequently, we believe the two-part subscription would support cost recovery by ensuring that most customer load is billed at a stable and predictable rate while maintaining revenue neutrality and preventing cost shifts.

We acknowledge CforAT's concerns that Staff's two-part subscription tariff proposal relies heavily on historic usage data that may not reflect low-income customer characteristics such as variation in household number, customer mobility, inelastic demand, and inability to load shift. At the same time, LBNL's analysis that supports Staff's proposal relies on historic customer usage data and shows that two-part subscription tariffs reduce structural bill impacts for customers with inelastic demand. Specifically, LBNL's analysis found that "the self-load-shape subscription yields the smallest overall bill impacts across customer classes, with median impacts being mostly near zero."[285] Essentially, DF rate customers enrolled on a two-part subscription tariff that do not respond to dynamic price signals are significantly less likely to be structural benefiters (or non-benefiters) thereby reducing the potential of cost shifting to non-participating customers. Based on our review, it is reasonable to conclude that many customers, including vulnerable customers who may have limited ability to shift their energy consumption in response to price signals, can benefit from the stability that two-part subscription tariffs can provide while still receiving appropriate price signals for any usage beyond their subscription level in two-part subscription tariffs. However, we do note that two-part subscriptions may not be a viable customer protection option for some low-income customers with higher mobility or that live in households with a variable number of residents. In these scenarios, it may be difficult to determine the historical load upon which a two-part subscription would be developed.

We also acknowledge CLECA's caution against overreliance on customer protection options such as the two-part subscription tariff for embedded cost recovery. In conjunction with our guidance for import prices to be EPMC-scaled or include a time-differentiated Revenue Neutral Adder to collect non-marginal costs, DF rates that incorporate two-part subscription tariffs would not be over-reliant on the subscription component for embedded cost recovery.

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[285] Working Group Report at 19.

Despite the customer protections and revenue stability benefits that two-part subscription tariffs have afforded to large customers, as demonstrated by their implementation by large utilities such as Georgia Power Company and Oklahoma Electric, we hear concerns raised by many parties, including the Joint IOUs, concerning its understandability, and ability to implement especially for small and medium customers. Therefore, we do not find sufficient evidence from the record to require that Large IOUs must include two-part subscription tariffs as a part of their initial DF rate proposals. However, it is reasonable to require that the Large IOUs must include appropriate customer protection options that provide bill and revenue stability benefits for each customer class in their DF Rate Proposals.

Guidance on Forward Transactions and Transactive Pricing Programs

We acknowledge concerns from the Joint IOUs that offering forward transactions in a Transaction Pricing program in DF rates may be too complex to implement, and as such should not be offered to all customer classes. Further, without a cost-benefit analysis demonstrating their ratepayer value as raised by Cal Advocates, it may not be prudent to require IOUs to develop proposals for such programs. As highlighted by CLECA, if forward transactions are offered on more than a week-ahead basis it would likely introduce a higher degree of forecasting risk. In the VCE/PG&E AgFIT pilot, this forecasting risk is decreased by only allowing forward transactions to be offered no earlier than a week ahead, affording customers with additional bill protection. Accordingly, it is reasonable for the Large IOUs to include Transactive Pricing in their DF Rate Proposals such that forward transactions are offered no earlier than a week ahead. This Transactive Pricing design provides valuable load shifting incentives and bill protection to medium-to-large commercial, industrial, or agricultural DF rate customers that can better plan and schedule their energy use.

<u>Rejection of Microgrid RC's Option Proposal</u>

As noted by Sierra Club, SBUA, Clean Coalition, and 350 Bay Area, customers enrolled on the Option would have the ability to only pay for energy that is consumed. While it appears to provide more flexibility for energy management, we reject the Option because it presents several implementation challenges that render it unsuitable for inclusion in DF Rate Proposals.

First, we concur with the Joint IOUs' observation that the Option would result in fundamentally different hourly prices depending on whether a customer's load is above or below their Option level, making it very difficult for automation systems to schedule customer load. As stated by the Joint IOUs, we acknowledge the unpredictability in DF prices if customers enroll in Microgrid RC's Option program. This unpredictability could impact customer understanding and significantly undermine the ability of IOUs to create DF rates that are revenue neutral.

Second, we agree with CLECA that because the Option is the only mechanism for fixed cost recovery there may result in undercollection of revenue from customers with significant year-to-year changes in usage, and that such revenue shortfalls could be exacerbated under expected near-term load growth scenarios. Given these substantial concerns regarding pricing predictability, customer understanding, automation compatibility, and revenue recovery, we do not consider the Option as a viable customer solution for DF Rate Proposals at this time.

Customer Protection Options Guidance

We adopt the following guidance for customer protection options in DF Rate Proposals. All customer protection options in Large IOU DF Rate Proposals must:

1. Ensure stability of revenue recovery and minimize structural rate impacts;
2. Reduce the impact of non-coincident peak demand charges and flat volumetric charges on customer incentives to respond to dynamic prices; and
3. Protect customers against extended periods of high dynamic prices which cannot be mitigated by load shift.

It is reasonable to provide the Large IOUs with flexibility to design customer-class appropriate protection options in DF Rate Proposals and we identify the following as viable approaches:

1. Two-part subscription tariffs, which may differ in design across different customer classes to account for differences in customer acceptance and load characteristics;
2. Approaches similar to VCE's price-adjustment, where the average of the dynamic price is adjusted with a scalar offset to recover the same revenues as a class-specific tariff;
3. Transactive pricing programs, if forward transactions, are offered no earlier than a week-ahead basis to minimize potential forecasting risks and are offered to large customers that can plan and schedule their energy use and;
4. Bill limiters or bill protection, with clear demonstration of how cost shifts will be minimized and price incentives preserved.

It is reasonable to require that all DF Rate Proposals include the following analysis for any proposed customer protection option:

1. Estimated customer bill impacts such as those generated by the LBNL subscription design tool developed as part of the Working Group process;

2. Rate and revenue impacts for both participants and non-participants;
3. Potential for cost shifting from participants to non-participants; and
4. Consideration whether incentives to respond to dynamic prices will be impacted, for example when a customer reaches their bill limit within a billing period.

If a Large IOU chooses to implement two-part subscription tariffs as their customer protection option, we recommend the following customer class-specific approaches:

1. For large customers with predictable hourly electricity usage profiles, we recommend a static, ex-ante subscription methodology similar to Georgia Power's and Oklahoma Gas and Electric's RTP programs, where the subscription hourly usage profile is predetermined and may be negotiated between the customer and the utility, possibly for an amount that is less than 100% of historical load.
2. For small customers, our recommendations include:
   a. Ex-ante baseline allowance subscriptions, where each customer's hourly subscription profile is based on the Tier 1 usage allowance for each climate zone rather than their individual historical usage.
   b. Ex-post-scaled subscriptions or "pay-for-your-load-shape" subscriptions; where the hourly shape of each customer's subscription is set ex-ante, but the overall quantity or size of the customer's subscription is scaled on a look-back basis to match the customer's actual total usage in each billing period.

7. Equity and Access

In this section, we will determine how DF Rate Proposals should consider the barriers and needs of low-income and disadvantaged communities (DACs) and seek to advance the Commission's ESJ Action Plan goals. First, we shall review proposals submitted by Staff, the Joint IOUs, and Microgrid RC to address this issue and related party comments. Second, we will review additional feedback from parties in response to April 2024 Ruling questions concerning the need, costs, and funding for a new study or amendments to the PG&E and SCE Expanded Pilots to better understand the needs of low-income and DAC customers to participate in DF rate programs.

Staff Proposal for Equity and Access

Staff proposes that all DF Rate Proposals and programs should conform with the Commission's ESJ Action Plan principles and consider the needs of low-income and DACs during the design process. To address these needs, Staff suggests that IOUs may consider how: (1) subscriptions and bidirectional prices in DF Rate Proposals can increase the affordability of zero-emission vehicles, (2) supplementary (DF rate) programs can enhance the benefits of DERs to provide local resilience, and (3) response to DF rate signals may be influenced by the types of bill protections and/or subscriptions that are offered to low-income and DAC customers.[286]

Joint IOUs Proposal for Equity and Access

The Joint IOUs suggest that low-income and DAC customers should have targeted Marketing Education & Outreach (ME&O) programs and be offered incentives to access technologies, such as smart devices and appliances, that address barriers and communicate risks associated with participation in DF rate programs. The Joint IOUs claim that such measures are needed because these customers are less likely to have flexible load technologies like EVs and smart thermostats and are more likely to have inelastic demand that limits their ability to shift load.[287]

[286] Working Group Report at 30-31.

[287] Working Group Report at 97.

The Joint IOUs describe three ways that DF Rate Proposals may help advance the ESJ Action Plan goals. These include: (1) enhancing electrification and grid resiliency and reducing (GHG) emissions, (2) early engagement with low income and DAC communities to obtain feedback on DF Rate Proposals, and (3) contracting with community-based organizations to conduct ME&O (regarding DF rate programs) that conceivably will provide job opportunities and enhance economic opportunities for residents.[288] Further, the Joint IOUs suggest that participation in DF rate programs from non-residential customers in disadvantaged communities should be encouraged through targeted marketing.

Microgrid RC Proposal for Equity and Access

Microgrid RC proposes that in-home controllers with connectivity are required for customer response to DF Rate Proposals.[289] For customers who cannot access controllers, Microgrid RC suggests that on-bill financing or direct utility installation are potential solutions to address this problem. For multi-unit dwellers, Microgrid RC recommends the installation of a Customer Controller to manage overall building load. Microgrid RC suggests that this control device will enable response to DF price signals at the property level. In situations where low-income or DAC customers live in areas where distribution systems are congested, Microgrid RC suggests that these customers would not be required to respond to DF rates if subscribed to Microgrid RC's Option plan. To alleviate distribution congestion, Microgrid RC recommends that utilities prioritize distribution upgrades in DAC areas. Further, Microgrid RC highlights that low-income and DAC customers should have access to locally sourced electricity

[288] Working Group Report at 97.

[289] Home-based distributed controllers are technology devices that enables customers to determine when to consume electricity based on price.

provided by customer solar or community microgrids, as it may reduce energy burden and build wealth.[290]

<u>Comments on Equity and Access</u>

Both Sierra Club and SBUA advise that the Commission offer technology incentives to DAC customers, with Sierra Club recommending that the Commission require incentives in areas that are adjacent to gas peaker plants. 350 Bay Area suggests that the Commission should consider offering low-cost DF integrated controls for Heating Ventilation and Air Conditioning units, include smart thermostats or smart plugs for programming and cycling Air Conditioning units, or other methods to defray costs, such as on-bill financing, to support adoption of automation in low-income communities.[291] CforAT expresses concern about the Joint IOU proposal, calling into question how "specifically targeted ME&O" and the potential for "targeted incentives" would be implemented; and with the Staff's proposal because it does not address the challenges associated with the up-front cost of DERs and customer protections.[292] [293] Further, CforAT claims that DF Rate Proposals are unlikely to significantly impact EV adoption among low-income and DACs and address landlord/tenant issues that need to be resolved prior to needed upgrades.

A range of parties suggest that the Commission should gain additional knowledge about DAC and low-income customer needs in pilots prior to enrolling these customers in DF rate programs. CforAT argues that Microgrid RC's and Staff's proposals do not adequately address DF rate challenges faced by

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[290] Working Group Report at 166.

[291] Working Group Report at 166.

[292] Working Group Report at 32-33.

[293] Working Group Report at 99.

low-income communities. Further, CforAT points out that Staff's proposal does not address how barriers to participation for low-income customers and DACs can be alleviated, and that many low-income households may have highly inelastic demand.[294] To this point, CforAT does support Staff's suggestion that analysis is needed to examine how barriers that prevent low-income customers from participating in DF rate programs can be addressed.[295] Alternatively, CLECA advises that the Commission should consider surveying low-income communities and DACs more directly to determine which DF Rate Proposal approaches would be most appealing. According to CLECA, household and EV loads in these communities should be considered separately, as EVs might be community-based rather than household-based.[296]

In response to equity-related questions posed in the April 24 Ruling, several parties provided feedback on the need for new or modified pilot studies to address DAC and low-income community participation in DF rate programs. The Joint IOUs suggest that input from DAC and low-income communities about participating in DF rate programs and the design of DF Rate Proposals should be obtained in current dynamic rate pilots including PG&E's Expanded Pilot 2 and SCE's Expanded Pilot that were approved in D.24-01-032.[297] [298] Further, the Joint IOUs recommend that issues raised by the April 24 Ruling related to equity and access should be included in these pilot evaluations if enough low-income

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[294] Working Group Report at 32-33.

[295] Working Group Report at 33.

[296] Working Group Report at 33.

[297] Working Group Report at 33.

[298] Working Group Report at 33.

customers decide to participate.[299] If equity issues are examined in these pilots, the Joint IOUs recommend that any results should be leveraged by SDG&E for future consideration in developing their dynamic rate programs targeted towards low-income customers.[300] If enough low-income customers do not participate in the pilots, PG&E and SCE suggest that they could modify their evaluations to examine why these customers are not engaged and work to identify any participation barriers, subject to additional funding.[301]

Additionally, the Joint IOUs cite the 2025 Low Income Needs Assessment (LINA) study that includes the following research questions on high and low usage low-income households about customer options on TOU rates:[302]

- How are customers impacted by peak and non-peak TOU rates?
- How does a customer's understanding of TOU rates impact their usage?
- Can we improve IOU communications and education on TOU rates?

The Joint IOUs explain that the results of the LINA study questions could be used to inform designing dynamic rates for low-income customers. Because the study questions and scope have already been finalized through extensive stakeholder engagement, the Joint IOUs recommend against revising or including any further questions in the LINA study.[303]

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[299] Joint IOU Opening Comments on May 22, 2024, at 11.

[300] Opening Comments of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company in Response to Administrative Law Judge's Ruling on Track B Working Group 1 Proposals and Issue 5 at 10.

[301] Joint IOU Opening Comments on May 22, 2024, at 12.

[302] Joint IOU Opening Comments on May 22, 2024, at 12.

[303] Joint IOU Opening Comments on May 22, 2024, at 12.

Microgrid RC suggests that the Commission should require each electric distribution company to adopt a plan for low-income deployment of real-time pricing in consultation with representatives of those communities.[304]

SBUA points out that existing and upcoming studies, such as the Community Based Organizations (CBO) Arrearages Case Management Pilot study authorized in D.24-02-046 and others referenced in R.18-07-005 (energy disconnections and reconnections rulemaking) are expected to provide significant data on how low-income residential customers respond to DF rates, including customer response to DF rates in various climate zones. [305]

Sierra Club expresses concern that a new study will not shed new light on how to best support DACs in the transition to dynamic pricing and will ultimately lead to delay, including delayed benefits to DACs.[306] Sierra Club also strongly suggests adding more variables, such as a dynamic rate element, to the CBO study authorized in D.24-02-046 on the basis of potential cost and implementation challenges.[307]

CalCCA states that customer studies should not be limited to low-income customers and recommended that the overall benefits of real-time pricing should be studied.[308] If the Commission directs the IOUs to conduct a new study, CalCCA proposes that the following questions are asked concerning low-income customers:

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[304] Microgrid Resources Coalition Reply Comments on June 12, 2024, at 2.

[305] SBUA Opening Comments on May 22, 2024, at 7-8.

[306] Sierra Club Opening Comments on May 22, 2024, at 3.

[307] Sierra Club Opening Comments on May 22, 2024, at 5.

[308] CalCCA Opening Comments on May 22, 2024, at 4.

- How can low-income and Disadvantaged Communities' customers achieve private energy and non-energy benefits on RTP rates?
- Is there a level of electrification technology adoption (e.g., automation) necessary to achieve private energy benefits for low-income customers?
- Do low-income customers lack access to the technology (smart devices, internet, etc.) necessary to benefit from RTP rates?
- Are there gaps in access to that technology between low-income customers and higher-income customers?
- Do low-income customers experience lower levels of load elasticity than higher income customers?
- What impact would increased price volatility from RTP rates have on low-income customer affordability (e.g., bill size month to month)?
- What consumer protections could be considered to reduce low-income customer affordability risk under RTP rates?

Finally, Cal Advocates also states that the Commission should not repurpose the CBO Pilot to study the impact of dynamic rates on low-income customers.[309] Cal Advocates echoes the opinion of Sierra Club that adding dynamic rate variables to this study would likely lead to customer confusion and could also reduce the accuracy of the study.[310] Cal Advocates notes that the Commission and IOUs should instead leverage the evaluations embedded within the current Expanded Dynamic Rate Pilots which include evaluations of ESJ communities.[311] As a result, Cal Advocates suggests that the Commission should

[309] Cal Advocates Reply Comments on June 12, 2024, at 7.

[310] Cal Advocates Reply Comments on June 12, 2024, at 7.

[311] Cal Advocates Reply Comments on June 12, 2024, at 7.

deny the Joint IOUs' request for additional funding for studying low-income communities in the (PG&E and SCE) Expanded Pilots.[312]

Guidance on Equity and Access for DF Rates

According to our evaluation of party proposals and comments, it is reasonable to direct the Large IOUs to modify the evaluation of PG&E and SCE's Expanded DF Pilots, authorized in D.24-01-032, to understand how low-income and DAC customers, including residential customers in multi-unit dwellings and non-residential customers, can increase their enrollment, enhance their usage behavior (*i.e*. conservation or load shifting), reduce bill impacts, and experience bill savings from DF rate programs. As stated by the Joint IOUs, the results of this evaluation can be leveraged by SDG&E for its own consideration of how DF rate programs can be tailored to serve the needs of low-income customers (i.e. ME&O, technology incentives, and DF rate design to promote customer understanding).

It should be noted that no parties that responded to the April 2024 Ruling questions pertaining to equity and access strongly supported the notion of a new study focused on the needs of low-income customers. Parties argue for such needs to be studied in a more cost-effective manner, including in existing dynamic rate pilots.[313] [314] [315] We thus believe it is reasonable to adopt Cal Advocates' suggestion that the Large IOUs should leverage the evaluations embedded within the current PG&E and SCE Expanded Pilots (which include evaluations of ESJ communities) to study of equity and access of low-income and

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[312] Cal Advocates Reply Comments on June 12, 2024, at 8.

[313] Joint IOU Opening Comments on May 22, 2024, at 11.

[314] SBUA Opening Comments on May 22, 2024, at 7.

[315] Sierra Club Opening Comments on May 22, 2024, at 3.

DAC customers to DF rates. As such, we agree with Cal Advocates' concerns about authorizing additional funding for further evaluations of low-income customers and dynamic rate programs.[316]

To achieve this, PG&E and SCE should respectively submit a plan in their DF Rate Proposals regarding how the PG&E and SCE Expanded Pilots will consider the following questions:

- how DF rates can be designed to be user-friendly; and
- how to identify and address the needs of low-income and DAC customers who may have an interest in subscribing to DF rates.

Further, we concur with the Joint IOUs' position that the upcoming 2025 LINA study contains questions that could inform the design of dynamic rates for low-income customers.[317] The LINA study will focus on how high and low usage low-income households may be impacted by peak and non-peak TOU rates, and their understanding of TOU rates.[318] Though not identical in scope and focus, the LINA study's findings are likely to be indicative of the experiences of low-income customers about dynamic rate programs given the study's focus on similarly time-variant TOU rates. Therefore, it is reasonable to direct PG&E and SCE to each file a Tier 1 AL within 90 days after the final evaluation reports from PG&E and SCE Expanded Pilots have been issued and findings have been obtained from the 2025 LINA study. The Tier 1 ALs shall describe any learnings from the PG&E and SCE Expanded Pilots coupled with those from the 2025 LINA study regarding how they will be utilized to more holistically analyze and

[316] Cal Advocates Reply Comments on June 12, 2024, at 7.

[317] Joint IOUs Reply Comments to on June 12, 2024, at 12.

[318] Joint IOUs Reply Comments to on June 12, 2024, at 12.

improve DF rate programs for low income and DAC customers in DF Rate Proposals in future GRC Phase 2 applications.

In reply comments to the April 2024 Ruling, parties cited other studies that were designed to assist in understanding the needs of low-income residential customers with respect to dynamic rates. As aforementioned, SBUA suggested that the CBO Arrearages Case Management Pilot could be relied upon instead of a separate study focused on low-income customers and dynamic rates.[319] However, the Joint IOUs replied that the CBO study was designed to address very different objectives.[320] This position was echoed by Cal Advocates and Sierra Club.[321] [322] We agree. The CBO study is not appropriate for the purpose of understanding the needs of low-income customers regarding dynamic rates as the study is not focused on low-income customers or their response to dynamic rates.

8. Load Serving Entity Participation

In this section, we will examine Staff, Joint IOU, and Microgrid RC proposals and party comments on those proposals, and provide guidance to IOUs regarding the design of DF Rate Proposals to enable the participation of LSEs.

<u>Staff Proposal for LSE Participation</u>

Staff proposes that DF Rate Proposals should have a uniform delivery component (*i.e.* uniform transmission and distribution rates) for both bundled and unbundled customers, including CCAs. Specifically, IOU dynamic rates

[319] SBUA Opening Comments to on June 12, 2024, at 7-8.

[320] Joint IOUs Reply Comments on June 12, 2024, at 3.

[321] Sierra Club Opening Comments on June 12, 2024, at 5.

[322] Cal Advocates Reply Comments on June 12, 2024, at 7.

should include a delivery component that is identical for equivalent bundled and unbundled customers.[323] This approach ensures consistency in delivery charges across different customer types and load serving entities.

According to Staff, CCAs should have the option to either design their own dynamic generation rate or adopt the incumbent IOU's dynamic generation rate for DF rates offered to their customers.[324] This flexibility allows CCAs to tailor generation rates for their specific customer base and resources while still participating in the broader DF framework. Additionally, Staff suggests that IOU applications should include proposals regarding how the IOUs will collaborate with CCAs on customer bill protection and management elements of DF rates, such as subscription design and transactive options. If the CCAs decide to implement alternative subscription and transactive options in DF rate programs, Staff recommends that IOUs collaborate with CCAs to determine how IOU delivery rate components and CCA generation rate components will be integrated. [325]

Joint IOU Proposal for LSE Participation

The Joint IOUs propose to collaborate with the CCAs to remove DF customer participation barriers by facilitating pilots and launching rate alternatives like CPP, Variable Peak Pricing (VPP),[326] and dynamic rates.[327] The

[323] Working Group Report at 35.

[324] Working Group Report at 35.

[325] Working Group Report at 34-35.

[326] In Variable Peak Pricing programs are similar to TOU programs except that prices during peak periods varies according to system conditions. https://www.publicpower.org/system/files/documents/Moving-Ahead-Time-of-Use-Rates.pdf

[327] Working Group Report at 100.

Joint IOUs prefer this approach because (1) CCAs are already partnering with IOUs to offer DF rates, (2) CCAs have expressed interest in offering CPP and VPP rate options but require assistance with data issues, (3) expanding CPP and VPP could yield early load reduction for CCA customers prior to the launch of DF rate offerings and (4) simultaneous launch of DF rates for CCAs and IOUs would decrease marketing and education expenses and reduce confusion for both sets of customers.[328]

Microgrid RC Proposal for LSE Participation

Microgrid RC proposes that all non-IOU LSEs such as CCAs must offer DF pricing to their customers and that CCAs may control DERs within their service territory. Microgrid RC also proposes that all DF Rate Proposals should have a Distribution Congestion Adjustment that is uniform for equivalent bundled (*i.e.* IOU customers) and unbundled customers (*e.g.* CCA customers) in reference to electricity imports and exports and DR so that CCA customers experience the same incentives as participants in IOU programs. According to Microgrid RC, CCAs should be able to adjust their dynamic generation rate if their (1) marginal cost of energy at a Pricing Node differs from the wholesale price based on their wholesale electricity agreements, and (2) generation resources within its territory may experience different aggregate line losses.[329]

Comments on Proposals for LSE Participation

The Joint IOUs agree with Microgrid RC that LSEs like CCAs should be able to design and offer their own DF rates.[330] CalCCA, SBUA, Sierra Club, VCE, Polaris Energy Services, and Gridtractor support Staff's proposal for CCAs to

[328] Working Group Report at 100.

[329] Working Group Report at 168.

[330] Working Group Report at 169.

develop their own dynamic generation rate or adopt the IOUs' generation rate component in CCA DF rates.[331] CLECA states that CCAs and direct access providers must develop their own rates to conform with CEC Load Management Standards.[332] Both CLECA and Sierra Club agree with Staff's recommendation that the delivery rate for IOUs and CCAs in DF rates should be uniform.[333] [334] To foster the development of CCA rates, the Joint IOUs, SBUA, CalCCA, Cal Advocates, and Sierra Club support on-going collaboration between the IOUs and the CCAs.[335] [336] [337] [338]

350 Bay Area supports LSE coordination to develop their own DF rates. Further, 350 Bay suggests that lack of access to customer data and load forecasts and legacy IOU billing systems prevent CCAs from offering better TOU, CPP, and potential VPP options to customers.[339] 350 Bay Area also claims that DF rates should have rate elements that account for differences in LSE energy prices and include consistent location-based prices for marginal grid capacity and operational costs. Additionally, 350 Bay Area recommends that each LSE should set their own marginal energy prices that may not resemble CAISO Pricing Node

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[331] Working Group Report at 35-36.

[332] Working Group Report at 35.

[333] Working Group Report at 35.

[334] Working Group Report at 101.

[335] Working Group Report at 35.

[336] Working Group Report at 98.

[337] Working Group Report at 100.

[338] Working Group Report at 101.

[339] Working Group Report at 100.

prices. Finally, 350 Bay Area suggests that each LSE should include the same location-specific capacity price components in DF rates.[340]

Cal Advocates highlights that the Commission should ensure that dynamic rates are available to bundled and unbundled customers on similar timelines to maximize the value of marketing and education expenses and limit customer confusion.[341]

Guidance for LSE Participation in DF Rate Programs

It is reasonable that each LSE should have the ability to offer DF rates based on the characteristics of its customer base (i.e. income, DER ownership, etc.) and resource portfolio, and that both bundled and unbundled customers include a uniform delivery component in DF rates, as it would ensure that delivery charges for different customer types and LSEs are similar. This uniform delivery component should address concerns from Microgrid RC and 350 Bay Area that all Large IOU DF Rate Proposals should reflect consistent location-based marginal grid capacity for bundled and unbundled customers. In turn, all LSE DF rate customers should experience the same incentives to load shift.

Moreover, it is reasonable for LSEs to have the option to develop their own dynamic generation rate. However, if LSEs adopt an incumbent Large IOU's dynamic generation rate, they are advised to set this rate based on an analysis of relevant data (*i.e.* generation costs, customer sales, and marginal energy prices at CAISO Pricing Nodes). Given the Joint IOUs' pledge to collaborate with LSEs to develop LSE DF rates, the IOUs' DF Rate Proposals should provide detailed proposals about this process.

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340 Working Group Report at 98.

341 Working Group Report at 100.

To provide transparency, it is reasonable that IOU DF Rate Proposals should include a detailed description regarding how the IOUs will collaborate with CCAs on various features of DF rates and DF rate programs, including but not limited to:

1. Developing generation and distribution components and customer bill protection and management elements of DF rates, such as subscription design and transactive options;
2. Creating and launching LSE DF programs in coordination with IOU DF programs, to utilize lessons learned from IOU DF pilots and ME&O efforts and foster customer understanding of both bundled and unbundled DF rate offerings; and
3. Ensuring that LSE DF rates conform with CEC LMS requirements.

9. Comments on Proposed Decision

The proposed decision of ALJ Rajan Mutialu and ALJ Carolyn Sisto in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _______, by ___________ and reply comments were filed on ____________, by _______________.

10. Assignment of Proceeding

President Alice Reynolds is the assigned Commissioner and Rajan Mutialu and Carolyn Sisto are the assigned ALJs in this proceeding.

Findings of Fact

1. The CEC Load Management Standards require that the Large IOUs seek Commission approval of at least one marginal cost-based dynamic rate for each customer class within twenty-one months of April 1, 2023.

2. Some amount of electricity is lost when it is delivered to customers through T&D lines.

3. One LBNL study showed that two-part subscription tariffs minimize structural impacts on customer bills and utility revenue recovery, while incentivizing customer load-shift behavior.

4. Low-income and DAC customers may have additional challenges for benefiting from dynamic rates.

Conclusions of Law

1. It is reasonable to (a) direct SDG&E to file a consolidated application for DF Rate Proposals to comply with the guidance in this decision for all customer classes, (b) direct PG&E to serve supplemental testimony in A.24-09-014 to comply with the guidance for DF Rate Proposals in this decision within 45 days of the issuance of this decision, and (c) direct SCE to serve supplemental testimony in A.24-12-008 to comply with the guidance for DF Rate Proposals in this decision within 45 days of the issuance of this decision.

2. It is reasonable to require the Large IOUs to use CAISO's day-ahead energy market price at DLAPs as the MEC in DF Rate Proposals to comply with the CEC LMS and effectively incentivize customer load shifting.

3. It is reasonable to require the Large IOUs to include a line loss factor in the MEC in their DF Rate Proposals to recover the cost of replacement electricity.

4. It is reasonable to require that each of the Large IOU's proposed methodologies to calculate line losses reflect the time or load-dependent nature of these losses.

5. It is reasonable to require that the MGCC price in Large IOU DF Rate Proposals must account for costs associated with both peak and flexible capacity needs during periods of grid stress.

6. It is reasonable for Large IOUs to update the revenue requirement target for the MGCC price on an annual basis in DF rates.

7. It is reasonable to direct the Large IOUs to propose a functional relationship between the peak MGCC price and net load that best balances strong price signals with revenue stability considerations.

8. It is reasonable to require that Large IOU DF Rate Proposals must also include a detailed evaluation to demonstrate how the proposed MGCC price function (1) does not unreasonably impact annual revenue recovery stability and (2) performs across a range of system conditions and years.

9. It is reasonable to require that each Large IOU's MGCC price function evaluation should include a comparison of revenue recovery variability with alternative functional approaches.

10. It is reasonable to require that each of the Large IOU's implementation of flex MGCC components should be based on each IOU's current allocation of marginal generation capacity costs to flexible capacity:

    a. For IOUs with existing flexible capacity allocations: If a non-zero percentage of MGCC has been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as SCE, where 40% of the total MGCC is allocated to flexible capacity), then it is reasonable that each IOU's DF Rate Proposal should include a flexible MGCC price component that is calibrated to recover a similar proportion of the MGCC value being used for DF rate design purposes. This MGCC value may be either from the most recently adopted ACC model, or the calculated MGCC value from an IOU's latest GRC Phase 2 proceeding testimony. IOU applications may use the flexible MGCC price design that is a function of the 3-hour system net load ramp as proposed by Energy Division and TeMix in the Working Group report.

b. For IOUs without existing flexible capacity allocations: If a percentage of MGCC has not been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as PG&E and SDG&E), then it is reasonable to require that such IOUs should propose a reasonable non-zero percentage to allocated to flexible capacity for DF rates in their DF Rate Proposals. The IOU's DF rate proposal should include a flexible MGCC price component that is calibrated to recover this proposed proportion of the MGCC value being used for DF rate design purposes. The IOUs should follow the guidance detailed regarding the design of the flexible MGCC price function (i.e., use of the flexible MGCC price design that is a function of the 3-hour system net load ramp as proposed by Energy Division and TeMix in the Working Group report).

11. It is reasonable to require that MGCC values used for Large IOU DF Rate Proposals should be consistent with the rate design directives adopted by the Commission under the Net Billing Tariff.

12. It is reasonable to require that Large IOU DF Rate Proposals should incorporate the statewide MGCC value from the most recently adopted ACC model as January 1, 2026 which is derived from IRP modeling and cost assumptions.

13. It is reasonable to provide the Large IOUs with the option to submit both the MGCC values from their most recent GRC Phase 2 applications (*i.e.* non-settled MGCC values that were calculated, submitted in testimony, and supported by workpapers) *and* the MGCC value that is an input to the ACC in their DF Rate Proposals.

14. It is reasonable to require that initial Large IOU DF Rate Proposals should include an MDCC that is location-based and appropriately recovers the costs that vary with customer class and voltage level.

15. It is reasonable to require Large IOUs to limit non-coincident demand charges in DF Rate Proposals to only recover demonstrably customer-specific non-peak distribution costs that are clearly shown to be caused by individual customer non-coincident demand rather than system or circuit peak loads.

16. It is reasonable to require the Large IOUs to include an hourly transmission capacity price component in DF Rate Proposals.

17. The Large IOUs should describe a plan to design MTCC price components that will be incorporated in their respective DF Rate Proposals.

18. It is reasonable to require that in DF Rate Proposals, marginal capacity prices for import rates should be scaled to recover the EPMC allocated portion of each IOU's total authorized revenue requirement (i.e., the EPMC allocated portion of "non-marginal" costs).

19. It is reasonable to provide the IOUs with two options for recovering non-marginal costs in import DF Rate Proposals: (1) using an EPMC scalar applied to time-varying marginal capacity prices, or (2) using a time-differentiated Revenue Neutral Adder.

20. It is reasonable to direct the Large IOUs to provide a detailed accounting of the elements comprising non-marginal generation costs, describe how revenues associated with those costs have evolved over time, and identify the long-term cost-drivers of non-marginal generation costs in their DF Rate Proposals.

21. It is reasonable to require that the Large IOUs recover revenue categories that are not already recovered through the scaling of time-varying rate components (e.g., marginal customer access costs, non-peak marginal distribution capacity costs, other non-marginal costs) through alternate rate

design elements in DF Rate Proposals to ensure that DF rates are revenue neutral.

22. It is reasonable to require Large IOUs to file a joint Tier 2 AL, no later than March 31 each calendar year, that proposes the annual MGCC update for DF rates using one of the following two options:

    a. The first option is to propose to use the annual MGCC value from the most recently adopted ACC for a particular year, as of January 1 of that year.

    b. The second option is to use the MGCC update process described by PG&E in advice letter 7243-E, which scales *calculated* MGCCs, that were either proposed or settled, in the most recent GRC Phase 2 proceeding.

23. It is reasonable for the Large IOUs to propose conducting a marginal distribution cost study in their respective GRC Phase 2 proceedings to propose MDDCs and escalation scalars.

24. If a Large IOU elects to include export compensation in a DF Rate Proposal, then it is reasonable to require that the proposal use asymmetric pricing, where export rates are based solely on unscaled marginal costs, while import rates include a scalar or a time-differentiated Revenue Neutral Adder to recover the EPMC-scaled portion of an IOU's authorized revenue requirement.

25. It is reasonable to require Large IOUs to provide customer protection options in their DF Rate Proposals for bill and revenue stability to enable wider adoption of hourly DF rates without creating large structural bill impacts for both participants and non-participants.

26. It is reasonable to require that the Large IOUs must include appropriate customer protection options that provide bill and revenue stability benefits for each customer class in their DF Rate Proposals.

27. It is reasonable to permit the Large IOUs to include Transactive Programs in their DF Rate Proposals that only allow forward transactions to be offered no earlier than a week ahead to certain DF rate customers that can plan and schedule their energy use.

28. It is reasonable to require that customer protection options in Large IOU DF Rate Proposals must:

   a. ensure stability of revenue recovery and minimize structural rate impacts;

   b. reduce the impact of non-coincident peak demand charges and flat volumetric charges on customer incentives to respond to dynamic prices; and

   c. protect customers against extended periods of high dynamic prices which cannot be mitigated by load shift.

29. It is reasonable to provide the Large IOUs with flexibility to design customer-class appropriate protection options in DF Rate Proposals and identify the following as viable approaches:

   a. two-part subscription tariffs, which may differ in design for different customer classes to account for differences in customer acceptance and load characteristics;

   b. an approach similar to VCE's price-adjustment, where the average of the dynamic price is adjusted with a scalar offset to recover the same revenues as a class-specific tariff;

   c. transactive pricing programs where forward transactions are offered no earlier than on a week-ahead basis to minimize potential forecasting risks, and offered to large customers that can plan and schedule their energy use; and

   d. bill limiters or bill protection, with clear demonstration of how cost shifts will be minimized and price incentives preserved.

30. It is reasonable to require that all Large IOU DF Rate Proposals include the following analysis for any proposed customer protection option:

   a. estimated customer bill impacts such as those generated by the LBNL subscription design tool developed as part of the Working Group process;

   b. rate and revenue impacts for both participants and non-participants;

   c. potential for cost shifting from participants to non-participants; and

   d. whether incentives to respond to dynamic prices will be impacted, for example when a customer reaches their bill limit within a billing period.

31. PG&E and SCE should each propose in their DF Rate Proposals how their own Expanded Pilots will consider and resolve the following questions:

   a. how DF rates can be designed to be user-friendly;

   b. how to identify and address the needs of low-income and DAC customers that may have an interest in subscribing to DF rates; and

   c. how to mitigate the impact of dynamic rates on low-income and DAC customers.

32. It is reasonable to direct PG&E and SCE to each file a Tier 1 AL within 90 days after the final evaluation reports from PG&E and SCE Expanded Pilots have been issued and findings have been obtained from the 2025 LINA study. The Tier 1 ALs shall describe any learnings from the PG&E and SCE Expanded Pilots coupled with those from the 2025 LINA study regarding how they will be utilized to more holistically analyze and improve DF rate programs for low income and DAC customers in DF Rate Proposals in future GRC Phase 2 applications.

33. It is reasonable that each LSE should have the ability to offer DF rates based on the characteristics of its customer base and resource portfolio, and that

both bundled and unbundled customers include a uniform delivery component in DF rates, as it would ensure that delivery charges for different customer types and LSEs are similar.

34. It is reasonable to require the Large IOU's DF Rate Proposals to include a detailed description regarding how the Large IOUs will collaborate with CCAs on various features of DF rates and DF rate programs, including but not limited to:

a. developing generation and distribution components and customer bill protection and management elements of DF rates, such as subscription design and transactive options;
b. creating and launching LSE DF programs with IOU DF programs, to utilize lessons learned from IOU DF pilots and ME&O efforts and foster customer understanding of both bundled and unbundled DF rate offerings; and
c. ensuring that LSE DF rates conform with CEC LMS requirements.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company must file one consolidated application that proposes demand flexibility rates for all customer classes to comply with California Energy Commission Load Management Standard requirements within 90 days of the issuance of this decision. The design of proposed demand flexibility rates must comply with the Commission's guidance described in this decision.

2. Southern California Edison Company must serve supplemental testimony in Application 24-12-008 that complies with California Energy Commission Load Management Standard requirements and with the Commission's guidance described herein within 45 days of the issuance of this decision.

3. Pacific Gas and Electric Company must serve supplemental testimony in Application 24-09-014 that complies with California Energy Commission Load Management Standard requirements and with the Commission's guidance described herein within 45 days of the issuance of this decision.

4. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must file a consolidated Tier 2 Advice Letter every year on or before March 31, 2026 and every year thereafter to seek Commission approval of marginal generation capacity cost updates. The advice letter shall describe how the marginal generation capacity cost update that is an input to the Avoided Cost Calculator for a particular year, as of January 1 of that year is utilized to update marginal generation capacity costs.

5. If Pacific Gas and Electric Company (PG&E), Southern California Edison Company, or San Diego Gas & Electric Company elect to update marginal generation capacity costs based on alternative methodologies, including the methodology specified in PG&E Advice Letter 7243-E, they collectively must file a joint Tier 2 Advice Letter on before March 31, 2026 and every year thereafter. The advice letter shall provide a comparative assessment of marginal generation capacity cost updates when the updates are based on the input to the Avoided Cost Calculator for a particular year, as of January 1 of that year or alternative methodologies.

6. If Pacific Gas and Electric Company (PG&E), Southern California Edison Company, or San Diego Gas & Electric Company elect to update marginal distribution capacity costs, they each must file a Tier 2 Advice Letter on before March 31 in the year when the update is requested. The advice letter shall include data and analysis demonstrating whether distribution capacity costs

have changed significantly, and if so, how the proposed adjustments reflect those changes.

7. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) each shall file a Tier 1 AL within 90 days after the final evaluation reports from PG&E and SCE expanded dynamic rate pilots authorized in Decision 24-01-032 (Expanded Pilots) have been issued and findings have been obtained from the 2025 Low Income Needs Assessment (LINA) study. The Tier 1 Advice Letters shall describe any learnings from the PG&E and SCE Expanded Pilots coupled with those from the 2025 LINA study regarding how they will be utilized to more holistically analyze and improve demand flexibility rate programs for low income and disadvantaged community customers in future General Rate Case Phase 2 applications.

8. Rulemaking 22-07-005 is closed.

This order is effective today.

Dated ____________________________, at San Francisco, California