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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF THE PUBLIC ADVOCATES OFFICE ON THE SCOPING MEMO AND RULING OF PHASE 1 OF ADVANCING DEMAND FLEXIBILITY THROUGH ELECTRIC RATES

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I INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these Opening Comments pursuant to the November 2, 2022 Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo and Ruling), seeking comments on Phase 1 of Rulemaking (R.) 22-07-005.[1] The Scoping Memo and Ruling establish two tracks for this rulemaking. Track A will establish an income-graduated fixed charge for certain and potentially all residential rates for all investor-owned electric utilities in accordance with Assembly Bill 205 (Stats. 2022, ch. 61) (AB 205) including small and multi-jurisdictional electric utilities. Track B will streamline and expedite the adoption of demand flexibility rates for large investor-owned utilities.[2] The Commission should prioritize the adoption of income-graduated fixed charges in order to remedy current inequities in electric rate design and promote electrification by reducing volumetric rates.

In response to the Scoping Memo and Ruling and the requests for party comments by December 2, 2022, Cal Advocates recommends that the Commission:

- Adopt Cal Advocates' revisions to Energy Division's (ED) proposal modifying the Electric Rate Design Principles (RDP).
- Adopt Cal Advocates' revisions to ED's proposal for new Demand Flexibility Principles.
- Modify the Scoping Memo and Ruling to clarify the scope for Track B Working Group 2.
- Modify the Scoping Memo and Ruling to establish a timeframe for updating the Demand Flexibility Principles at the start of Phase 2 of this proceeding.

[1] Scoping Memo and Ruling, p. 9.

[2] Scoping Memo and Ruling, p. 2.

II RESPONSES TO QUESTIONS FOR PARTY COMMENT ISSUED IN SECTION 6 OF THE SCOPING MEMO AND RULING

The Scoping Memo and Ruling invites parties to comment on five questions related to the scope of the proceeding. Cal Advocates provides its comments to those questions in this section.

1. Should the Commission adopt the staff proposal for modifying the electric rate design principles applicable to all electric rates of the large investor-owned electric utilities?[3] Why or why not?

The Commission should adopt the ED staff proposal, with the following revisions, to provide updated guidance on development of electric rates:[4]

- RDP 1) All residential customers (including low-income and medical baseline or equivalent) should have access to enough electricity to ensure their essential needs (health, safety, and full participation in society) are met at an affordable cost.

ED's proposed principle should be clarified to apply to customers who have medical baseline status or something equivalent. For example, in Decision (D.) 22-04-004, the Commission adopted a line-item discount for medical baseline customers on Pacific Gas and Electric Company's non-tiered time-of-use rates.[5] This discount is the equivalent to the discounts medical customers would receive through the medical baseline on tiered rates.[6] Principle 1 should also apply to these customers who receive the equivalent of medical baseline.

- RDP 3) Rates should be based on cost-causation principles and avoid ~~cost shifts~~ cross subsidies.

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[3] See ED's full proposal in OIR to Advance Demand Flexibility Through Electric Rates, Phase 1 Scoping Memo and Ruling, CPUC Rate Design & Demand Flexibility Principles Staff Proposal Attachment, p. 16 of pdf.

[4] Throughout this document, strikethroughs show proposed deletions and underlines show proposed additions.

[5] D. 22-04-004, p. 22.

[6] D. 22-04-004, p. 6.

ED's proposal to add language to avoid cost shifts could be interpreted to avoid both new cost shifts moving away from cost causation and correcting for existing cost shifts to go back towards cost causation. By revising ED's proposal to generally avoid cross subsidies instead, the principle would guide rate designs closer to cost causation as a subsidy implies a shift away from costing. This change also aligns better with RDP 7 which refers to cross subsidies.

- RDP 5) Rates should optimize use of existing grid infrastructure and ~~limit~~ reduce long-term infrastructure costs.

Cal Advocates recommends revising ED's proposal by replacing "limit" with "reduce." "Limit" implies a specific cost limit could be established and could be too restrictive if the recovery of some long-term infrastructure costs is necessary. Whereas "reduce" accomplishes the same objective but is not as restrictive.

- RDP 6) ~~Customer should have options to manage their bills~~. Rates should be stable and understandable and provide customer choice.

Cal Advocates disagrees with ED's proposed change to RDP 6 and recommends retaining the current text. No other principle explicitly advocates for "stable" or "understandable" rates, which are necessary to protect customers. Rate stability addresses issues such as rate shock, where rates could have high fluctuations from one period to another. In so doing, rate stability helps protect against negative impacts to a customer's ability to plan for and pay their bills. Rates should also be understandable so that customers have some ability understand and make informed decisions on what rates to select. Customer choice also accounts for options to manage bills so the change is unnecessary.

- RDP 9) ~~Rates should encourage customer behavior that improves system reliability~~. Rates should encourage economically efficient decision making that supports system reliability.

Cal Advocates recommends retaining the original principle and expanding it to include system reliability. ED's proposal could lead to restrictions in available rate designs. For example, ED's proposed change could be interpreted to support moving all customers to real-time pricing (RTP) rates under the assumption that such rates would lead to customer behavior that improves system reliability. Cal Advocates' recommended revisions accommodate less granular rate options that still support system reliability.

- RDP 10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates and minimizes <u>and appropriately considers</u> the bill impacts associated with such transitions.

Cal Advocates disagrees with ED's proposal to remove the terms "and appropriately considers" from RDP 10, and recommends the Commission reverts to the current text. ED's proposal does not explain why this change is necessary or an improvement. Appropriate consideration of the bill impacts associated with transitions to new rate structures is substantively beneficial, for example by allowing the Commission to better address affordability concerns, and to account for potential rate shock. The language should remain in this principle to reflect this concept.

2. Should the Commission adopt the staff proposal for new demand flexibility design principles applicable to all demand flexibility rates of large investor-owned electric utilities? Why or why not?

The Commission should adopt the ED staff proposal for demand flexibility principles (DFP), with the following revisions:

- DFP 1) Demand flexibility tariffs should provide a dynamic price signal that can be easily integrated into standardized third-party DER and demand management solutions <u>in accordance with the California Energy Commission's Load Management Standards.</u>

Cal Advocates recommends DFP 1 be revised to include a reference to the California Energy Commission's (CEC) Load Management Standards (LMS) because there are many overlapping areas between the latest LMS revisions and the Demand Flexibility initiative. For example, Section 1623 in the LMS outlines the Load

Management Tariff Standards,[7] which requires each investor-owned utility (IOU) to develop marginal cost-based dynamic rates on a time interval of no more than one hour.[8] The LMS updates also require that dynamic rates be machine readable, in part so that third parties can easily integrate demand management solutions. The LMS updates align very closely with DFP 1 and therefore DFP 1 should explicitly mention the LMS to ensure IOUs and other parties coordinate to the best extent possible.

- DFP 2) Dynamic prices should reasonably and accurately ~~integrate the value of energy, generation capacity, distribution capacity, and transmission capacity (to the extent feasible) based on~~ reflect ~~real-time~~ grid conditions.

Cal Advocates recommends simplification of DFP 2 to avoid presuming the specific components that should be included in dynamic prices. DFP 2 presumes that energy, generation capacity, distribution capacity, and transmission capacity are all equal and the associated costs should be recovered through dynamic pricing. However, each component has different nuances and will likely have different rate designs that will need to be considered for inclusion in a particular rate design. For example, generation capacity and distribution capacity pricing components are vastly different. The method for designing each pricing component will involve different data inputs and levels of locational granularity. On the other hand, recovery of transmission capacity costs through dynamic rates is an unresolved issue. There is no existing dynamic rate that includes transmission capacity in the hourly price signal, and it is premature to assume that the inclusion of transmission capacity pricing will be beneficial.

The Commission should not assume the inclusion of each specific component in dynamic rates. Instead, it should allow for greater consideration of the costs, benefits and impacts of the inclusion of each component. For example, inclusion of locational granularity for distribution and transmission capacity has equity implications that require further discussion. Additionally, Cal Advocates agrees that whichever components are

[7] Docket Number 21-OIR-03, TN # 245996. Notice of Third 15-Day Public Comment Period Proposed Revision to the Load Management Standards contain the most up-to-date LMS revisions (LMS Update).
[8] LMS Update, p. 12.

included in rates should be tied to grid conditions, but what is considered "real-time" has not been determined. For the time being, this DFP should be simplified.

- DFP 3) ~~The systems & processes needed to calculate the dynamic price signal should be able to integrate~~ Both bundled and unbundled rate components should be integrated into the systems and processes needed to calculate the dynamic prices so that all Load Serving Entities can elect to participate.

DFP 3 is focused on ensuring that Community Choice Aggregators (CCAs) and other Load Serving Entities (LSEs) are able to provide customers with dynamic rate options. This principle is in alignment with the LMS update, discussed in DFP 1 above, and this principle clarifies further the importance of including bundled and unbundled rate components in the systems and processes developed for dynamic prices. Cal Advocates' edits aim to clarify the principle.

- DFP 4) Demand flexibility tariffs should be designed in accordance with all CPUC electric rate design principles.

Cal Advocates does not have edits to DFP 4 but recommends reordering this principle to be first among the DFPs as it is a broader principle that addresses the relationship between demand flexibility tariffs and other rates.

- DFP 5) Customers should have access to tools and mechanisms ~~(such as load shape subscriptions, forward transactions, bill protection, etc.)~~ that enable them to plan and schedule their energy use ~~while managing the monthly variability of their bills~~.

Cal Advocates recommends simplification of DFP 5. The specificity in this principle is unnecessary and can reference or mirror the RDP 6 on customer choice.

The proposed DFP 5 presumes load shape subscriptions, forward transactions, and bill protection to be successful tools and mechanisms that enable customers to plan and schedule their energy. Since there is limited data on the effectiveness of load shape subscriptions, forward transactions, and bill protection (in the context of dynamic pricing) this DFP should not explicitly list these tools and mechanisms. As shown in Table 1 below, the majority of the approved dynamic pricing pilots are not complete.

The measurement and evaluation (M&E) reports from these pilots will provide information on how effective and adaptable customers are to dynamic rates and how they enable them to plan and schedule their energy use.

It is important to consider the impact of each of the available tools and mechanisms before codifying them in these DFPs. For example, bill protection for dynamic rates typically means that customers are provided with a guarantee that their new bill under the new rate will not exceed what they were originally paying on their otherwise applicable tariff. Providing bill protection to customers increases the cost of dynamic rate programs and might result in shifting costs to non-participants. Similarly, without supporting data, it should not be presumed that customers can manage the variability of their bills. Pilots testing these concepts are still incomplete. Customers should have tools and mechanisms available to plan and schedule their usage, but beyond that basic principle it has yet to be determined which tools and mechanisms would best accomplish this.

3. **How should the Commission support the implementation of the amendments to the California Energy Commission's Load Management Standards?**

The Commission should include the CEC's revised Load Management Standards (LMS)[9] into the requirements established in the instant proceeding, R.22-07-005. Incorporation of the outcomes from the CEC's Load Management Rulemaking[10] into the Demand Flexibility Rulemaking will minimize duplication of efforts between the implementation of the LMS and the Demand Flexibility Rulemaking's requirements. From a timeline perspective, the LMS updates are ahead of the Demand Flexibility Rulemaking schedule. The CEC requires the IOUs to comply with the updated LMS by

[9] Docket Number 21-OIR-03, TN # 245996. Section 1621, Section 1622, Section 1623, Section 1624 and Section 1625 within the Notice of Third 15-Day Public Comment Period Proposed Revision to the Load Management Standards contain the most up-to-date LMS revisions.

[10] The CEC Load Management Rulemaking (Docket 21-OIR-03) established the updated LMS.

October 2024.[11,12] The established January 2025 deadline set in the Scoping Memo should therefore provide the large IOUs enough time to file applications for the approval of compliant demand flexibility rates.

First, Cal Advocates recommends the Commission participate in and contribute to the Working Groups that are already underway for implementation of the LMS updates. The first set of Working Groups focused on the LMS and the Market Informed Demand Automation Server (MIDAS) began on November 9, 2022. The objective of the Working Group is "to provide a forum for CEC staff and stakeholders to discuss issues and potential improvements or enhancements to MIDAS. The working group will also provide an opportunity for members to learn how to use MIDAS and ensure it supports load management goals."[13] The Commission should support the implementation of MIDAS because it will be the central publicly available database for rates. MIDAS will provide a standardized framework for publishing machine-readable rates, which is necessary to facilitate customers' ability to link their load management devices to rates. The Commission should not duplicate MIDAS by developing another database and instead should coordinate with the CEC's efforts.

Second, Cal Advocates recommends the Commission coordinate with the CEC's efforts to establish public programs that will "encourage mass-market automation of load management through information and programs."[14] The success of dynamic rates will

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[11] 2022 Load Management Rulemaking. 21-OIR-03. Third 15-Day Proposed Revisions to the Load Management Standards. Section 1621(d) (1) Each Large IOU shall submit a plan to comply with Sections 1621 and 1623 of this article to the Executive Director no later than six (6) months after the effective date of these standards.

[12] "Under the updated standards, which will take effect April 1, 2023, Pacific Gas and Electric Company, Southern California Edison Company, Sacramento Municipal Utility District, San Diego Gas & Electric, Los Angeles Water and Power, and large community choice aggregators will be required to make the following improvements..." CEC Adopts Standards to Help Consumers Save Energy at Peak Times, available at: CEC Adopts Standards to Help Consumers Save Energy at Peak Times accessed November 18, 2022.

[13] Workshop notice for the first LMS and MIDAS working group on November 9, 2022. Sent to workshop participants on November 2, 2022.

[14] LMS Updates, p. 14. LMS updates require each IOU to conduct a public information program to inform and educate customers on why marginal cost-based rates and automation are needed, how they will be used and how these rates can save customers money.

largely depend on customer acceptance. Because the default TOU rollout only finished a couple of years ago, customers are still largely unfamiliar with dynamic rates. To streamline these efforts the Commission should ensure that its efforts for public information are closely aligned with the CEC's to ensure that the public is receiving the same message, or a consistent one, about load management.

4. **Should the Commission expand any of the existing dynamic rate pilots as a near-term solution to benefit system reliability?**

It is unreasonable to expand pilots before the evaluations are complete. It is important to understand how these pilots impact system reliability, as well as the degree to which customers understand dynamic rates and participate in load-shifting behavior. Additionally, any unintended consequences associated with the existing dynamic rate pilots need to be understood and addressed before expanding any of the pilots. The Commission has already delineated implementation details, eligibility requirements, M&E plans, and budgets for the approved pilots shown below in Table 1. Each of these pilot elements should be reconsidered before expanding a pilot. Finally, there are implementation considerations that should also be addressed. Cal Advocates recommends any expansion of the already approved dynamic pricing pilots be postponed until all the necessary considerations have been carefully deliberated in Working Group 2. IOUs will likely need both time and money to modify billing systems in order to expand any of the dynamic rate pilots.

a. **If so, which pilots should the Commission expand and why?**

At this time, Cal Advocates recommends that the Commission postpone expansion of any of the existing dynamic rate pilots until preliminary M&E have been completed, implementation considerations have been addressed. The table below delineates the details of all of California's IOU's existing dynamic rate pilots and programs, including their current timelines.

Table 1: Overview of Approved and Pending IOU RTP Pilot Programs

Utility	Proceeding	Decision	Summary of Program	Program Dates
PG&E	A.20-10-011	D.21-11-017 (import) D.22-10-024 (export)	Day-Ahead hourly RTP import and export rate for Battery Electric Vehicles	October 2023 – October 2026
	A.19-11-019	D.22-08-002 (pilot and MGCC)	RTP pilot with same import rate design as the pilot in A.20-10-011 for residential, small business and agricultural customers. Also includes customer preference study.	October 2023 – September 2025
	R.20-11-003	D.21-12-015	Agricultural Pumping Dynamic Rate Pilot, implemented in coordination with Valley Clean Energy.	May 2022 – May 2024
SCE	n/a	n/a	Permanent RTP rate (SCE TOU-8) based on 7 pre-set prices which are triggered based on temperature and is available to non-residential customers only	1978 – present
	CEC EPC-15-054	n/a	RATES Epic Pilot Stage 1, proof of concept pilot for TeMix's transactive software platform.	2017 – 2019
	R.20-11-003	D.21-12-015	RATES Pilot Stage 2, updated pilot to include additional customer classes	May 2022 – May 2024
SDG&E	R.13-11-007 R.18-12-006	D.16-01-045	Vehicle Grid Integration RTP rate (Power Your Drive) for commercial electrical vehicles with SDG&E-owned charging equipment	June 2017 – December 2020
	A.21-12-006 and A.21-12-008 (consolidated)	Open proceeding, intervenor testimony due December 30, 2022.	RTP pilots directed by Commission in D.21-07-010 (GRC2) and D.20-09-025 which directed SDG&E to propose a credit for export rate for EV customers.	TBD

The Commission should allow parties in Working Group 2 to explore expansion of existing pilots. Specifically, the IOUs can provide more details on logistical details associated with expanding the pilots. Parties can discuss the costs and benefits of expanding each of the pilots. Expansion of any of these pilots prior to these discussions would be premature.

b. How should any of the expanded pilots be modified?

Expansion of any of the already approved dynamic rate pilots will inherently call for modifications to budgets and timelines. During Working Group 2 discussions, parties can discuss whether it would be prudent to modify evaluation criteria to include research objectives that are specific to the new demand flexibility principles. As was recently witnessed in PG&E's Petition for Modification (PFM) to its Day-Ahead Hourly Real Time Pricing (DAHRTP) Commercial Electric Vehicle (CEV) rate pilot, expanding M&E to include additional reporting criteria can be very costly.[15] Furthermore, adding new rate schedules to billing systems can also significantly increase budgets.[16]

Nonetheless, if budgets, timelines, and evaluation criteria can be prudently updated, and if preliminary M&E results show a particular pilot to be successful, then Cal Advocates would recommend expanding participation caps for those customer groups which exhibited the most successful outcomes as measured by its program's target metrics. Eligibility criteria might also be expanded if a particular pilot proves to be beneficial for participants and non-participants. Given that these important issues should first be addressed, Cal Advocates recommends any expansion of the already approved

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[15] PG&E's PFM to D.21-11-017 was filed on November 4, 2022. In the PFM PG&E requests the Commission, "1) provide flexibility related to the budget amounts contained within the Decision, 2) authorize costs for billing system changes and program management, which were identified in the Decision, but not explicitly approved, 3) authorize an additional $515,000 for the increased Measurement and Evaluation (M&E) work for the optional DAHRTP rate for a total estimated M&E budget of $656,000, and 4) modify the dates for filing advice letters for additional amounts for the customer enablement tool and rate comparison tool under Ordering Paragraph (OP) 6." PG&E's PFM is available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K525/498525947.PDF.

[16] ED CalFUSE Whitepaper, p. 104.

dynamic pricing pilots be postponed until all the necessary considerations have been carefully deliberated.

5. **Beyond the six-element California Flexible Unified Signal for Energy (CalFUSE) policy roadmap proposed by Energy Division staff, what alternate proposals for hourly, marginal cost-based rates should the Commission consider to enable widespread adoption of demand flexibility and support the implementation of the amendments to the California Energy Commission's Load Management Standards?**

Cal Advocates recommends the lessons and outcomes of the Joint Marginal Generation Capacity Cost (MGCC) Study be considered in conjunction with, and as alternatives to, Elements 2, 3 and 5 of the CalFUSE proposal. The CalFUSE proposal does not consider the lessons from the MGCC Study from PG&E's DAHRTP and General Rate Case Phase 2 (GRC2) proceedings, Applications (A.) 20-10-011 and A.19-11-019, respectively.[17] It would be remiss to disregard the outcomes of the five months of data collection and analysis from subject matter experts representing different interest groups with nearly 100 years of collective experience in the field.[18] The resulting pricing signal from the MGCC Study meets many of the same goals of the CalFUSE framework without deviating from traditional rate structures; and it is the most stable rate in comparison to the other rate structures considered in the Study.

CalFUSE Element 2 proposes to use the California Independent System Operator (CAISO) locational marginal price "to reflect the localized marginal price of energy."[19] The proposal notes that "retail electricity prices linked to CAISO market energy cost would encourage development of demand flexibility solutions and incentivize [behind-the-meter distributed energy resources] BTM DERs to optimize operations, yielding substantial system customer benefits."[20] Element 2 further notes that the use of day-of

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[17] D.22-08-002 Decision Adopting Real-Time Pricing Pilot and Marginal Generation Capacity Cost Study and its Usage. The MGCC Study is included as Attachment A.

[18] A.20-10-011, Exhibit PG&E-20, Joint Stipulation on Study for MGCC Rate Design Issue (MGCC Stipulation), pp. 3-4.

[19] ED CalFUSE White Paper, p. 46.

[20] ED CalFUSE White Paper, p. 46.

CAISO market prices have the potential to "create additional economic opportunity and enable customer BTM DERs to capture more value[,]" and should be considered in a stakeholder workshop which compares the day-of prices to day-ahead ones.[21] The MGCC Study used the CAISO day-ahead market (DAM) to develop the formulations of the hourly MGCC value and capacity short fall metrics .[22] Parties in Track B Working Groups should consider the merits of day-of prices versus day-ahead prices also presented in the MGCC Study.

The MGCC Study examined the best fit between alternative formulations of an hourly MGCC rate and capacity shortfall and reliability metrics.[23] The MGCC Study also analyzed the relationship between a number of different variables and the conditions of the CAISO grid.[24] The resulting pricing formula is a probability-based function based on a logistical regression of Restricted Maintenance Operations (RMO) events which is optimized to recover the total MGCC[25] in an average year.[26] The price signal is more reflective of actual grid conditions relative to a traditional non-time varying MGCC price signal. Additionally, the MGCC Study found that a localized price signal would be costly to implement, difficult for customers to understand, and less stable over time.[27]

The MGCC study focuses on marginal capacity costs, which relates to Elements 5 and 3. Subscription-based rates, which are proposed in CalFUSE (Element 5), are a big departure from traditional marginal cost-based rates. Element 3 of CalFUSE argues that its proposed price signal is linked to marginal capacity costs, dynamic, and scaled to recover revenues, and would therefore be better aligned with marginal costs than

[21] ED CalFUSE White Paper, p. 48.

[22] D.22-08-002, Attachment A, pp. 3 – 4.

[23] D.22-08-002, Attachment A, pp. 3 – 4.

[24] D.22-08-002, Attachment A, p. 4.

[25] The total MGCC value is determined in PG&E's General Rate Case Phase 2. The MGCC value used in the study was $76.35/kW-year. D.22-08-002, Attachment A, p. 1.

[26] D.22-08-002, Attachment A, p. 52.

[27] D.22-08-002, Attachment A, pp..19 – 20.

traditional rates.[28] The MGCC Study aligns more closely with traditional rate structures while also being dynamic, linked to marginal costs, and appropriately scaled to recover revenues.

For the reasons explained above, Cal Advocates proposes consideration of the MGCC price signal in conjunction with the CalFUSE proposal Elements 2, 3, and 5. Application of the MGCC Study would include real-time pricing from the CAISO wholesale market (Element 2) to set dynamic capacity-based electricity prices (Element 3) without using subscription-based rates (Element 5) which deviate from traditional marginal cost-based rates.[29] The MGCC Study can also be leveraged to support the implementation of the amendments to the CEC LMSs. Updates to Section 1623(a) of the LMS require each IOU to develop marginal cost-based rates on an hourly time interval (at a minimum).[30] Updates to Section 1623(b) require the IOUs to upload existing time-dependent rates to MIDAS.[31] The pricing signal developed in the MGCC Study supports the implementation requirements from the CEC LMS updates. The MGCC pricing signal is an hourly rate and can be uploaded with the other rate components to MIDAS. Alternatively, the subscription-based tariffs proposed by the CalFUSE framework will likely be more challenging to integrate with MIDAS since there is a customer-specific true-up process required to account for the differences in customer usage between the subscription and actual usage.

III. GENERAL COMMENTS FOR THE SCOPING MEMO AND RULING

Cal Advocates offers two additional recommendations for the Scoping Memo and Ruling which are not captured in the above responses.

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[28] ED CalFUSE White Paper, p. 53.

[29] ED CalFUSE White Paper, p. 4.

[30] LMS Updates, p. 12.

[31] LMS Updates, p. 12.

1. **The Commission should modify the Scoping Memo and Ruling to clarify the scope for the Track B Working Group 2.**

The Commission should revise the scope for the Track B Working Group 2. Working Group 2 should focus primarily on outlining the processes and systems needed for access to prices and responding to price signals. Cal Advocates' Opening Comments[31] recommended the Commission identify what systems need to be created and what organizations will develop, fund operate and maintain such systems.[32] Cal Advocates explained that the Commission must determine how the non-IOU LSEs, such as Community Choice Aggregators, will fit into the framework, how costs will be shared, and what responsibilities they will have.[33] Determining what systems will need to be created, what organizations will be involved, and who will bear responsibility is an important first step in assessing the costs associated with this framework.[34] These broader implementation questions must be considered before specific technical details.

Cal Advocates recommends the Commission modify Section 3, third paragraph, to read as follows:

> Working Group 2 will address Issue 4 of Track B (systems and processes for access to prices and responding to price signals). The purpose of this working group is to determine what organizations will be involved and who will bear responsibility for any proposed systems and processes needed for access to prices and responding to price signals, such as computation of dynamic electricity prices, billing, and settlement. For each system and process identified, Working Group 2 will consider what organizations will be involved, who will fund, operate, and maintain such systems or processes. Working Group 2 will also consider how non-IOU Load Serving Entities (LSEs) will be incorporated in each identified system and process. The systems and processes will be designed to support widespread adoption of demand flexibility rates, comply with the California Energy Commission's Load Management Standards, and align with the

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[32] R.22-07-005, Cal Advocates Opening Comments, p. 9, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451555.PDF.

[33] R.22-07-005, Cal Advocates Opening Comments, p. 9, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451555.PDF.

[34] R.22-07-005, Cal Advocates Opening Comments, p. 9, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451555.PDF.

Commission's electric rate design principles and demand flexibility design principles.

Cal Advocates recommends the above edits to the Working Group 2 mandate to specify responsibility for the systems and processes identified. The edits also explicitly require Working Group to consider non-IOU LSEs involvement.

2. The Commission Should Allow Enough Time to Inform and Update the Demand Flexibility Principles

At the beginning of Phase 2 of this proceeding, the Commission should take another look at the Demand Flexibility Principles as evolving discussion on demand flexibility could lead to the need for changes. For example, since the Commission proposes the Working Groups occur concurrently, Working Group 2 will not have finalized rate design and demand flexibility design principles until March 2023. The systems and processes discussed in Working Group 2 could provide more insights to inform the Demand Flexibility Principles. Similarly, results from the already authorized pilots could provide data driven updates to the Demand Flexibility Principles. In general, the new Demand Flexibility Principles are trailblazing and innovative. As technology evolves and public knowledge about these new rate designs grow, the Demand Flexibility Principles will likely need to be modified.

IV. CONCLUSION

For the above stated reasons, Cal Advocates recommends that the Commission adopt the revisions proposed in these comments.

Respectfully submitted,

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