BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005 Filed: July 14, 2022

PACIFIC GAS AND ELECTRIC COMPANY (U-39) OPENING COMMENTS TO THE PHASE 1 SCOPING MEMO AND RULING

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PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pursuant to the *Assigned Commissioner's Phase 1 Scoping Memo and Ruling* (Phase 1 Scoping Memo), Pacific Gas and Electric Company (PG&E) files these Opening Comments. The Phase 1 Scoping Memo invites parties to file concurrent opening comments, including addressing five specific questions, by December 2, 2022, with concurrent reply comments due January 4, 2023.[1]

As procedural background, PG&E filed opening and reply comments providing initial input on scope of issues, schedule, categorization, and whether evidentiary hearings may be needed.[2] On September 16, 2022, PG&E participated in the Pre-Hearing Conference (PHC) to discuss schedule and issues in scope for Phase 1 of this proceeding. On September 1, 2022, the Administrative Law Judge's (ALJ) Pre-Prehearing Conference (PHC) Ruling presented a draft proposed scope and schedule and informed the parties, among other things, that comments at the PHC should focus on Phase 1 issues. On September 27, 2022, PG&E submitted post-PHC comments which included as attachments: PG&E's recommended modifications for scoping items, estimated timeline for real-time pricing (RTP) pilots, and schedule proposals.

On November 17, 2022, PG&E participated in Energy Division's workshop (RDP workshop) regarding rate design principles and demand flexibility guidelines during which

1 Phase 1 Scoping Memo (Nov. 2, 2022), pp. 10-11, p. 15.

2 R.22-07-005. PG&E's Comments in Response to Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates (August 15, 2022). PG&E's Reply Comments in Response to Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates (August 25, 2022).

Energy Division staff explained their rationale regarding the revised rate design principles and demand flexibility guidelines. Energy Division staff requested substantive discussion regarding the principles and guidelines be included in these comments.

Overall, PG&E supports the California Public Utilities Commission (Commission or CPUC) and stakeholders' engagement to address rate design principles and demand flexibility guidelines but requests additional modifications to encourage successful implementation. Below, PG&E responds to the five questions (and subparts) from the Phase 1 Scoping Memo. For convenience, the following summarizes PG&E's response:

1. The Commission should adopt the revised rate design principles, as modified by PG&E herein, because these additional modifications provide further clarification, better align with state policy goals, and support a more positive customer experience,

2. The Commission should adopt the revised demand flexibility guidelines, as modified by PG&E herein, because these modifications add needed specificity for and flexibility in conducting a successful proceeding,

3. Regarding the amended California Energy Commission (CEC) Load Management Standards (LMS):

   a. It seems premature to determine how the Commission should "support the implementation of the amended CEC LMS" because more coordination and alignment is first needed between the CPUC and CEC, that is transparent for and communicated to all stakeholders, and

   b. It seems premature to determine "what other alternate proposals are necessary for widespread adoption of the CEC's amended LMS" until after the LMS becomes effective without recognizing the limits of CPUC ratemaking jurisdiction, such that involvement is also needed from CCAs and municipal utilities if climate goals are to be achieved on a statewide basis,

4. Subject to conditions described below, PG&E is open to a thoughtful expansion of certain dynamic rate pricing pilots, through Track B's process, currently scoped and scheduled to start in Q2 2023.

II. DISCUSSION

As a preliminary matter regarding the Phase 1 Scoping Memo of this proceeding, PG&E generally supports the creation of Tracks A and B and Working Groups 1 (guidance for demand flexibility design) and 2 (systems and processes for access to prices and responding to price signals). PG&E shares the sense of urgency related to meeting California's energy and climate goals. Nonetheless, while PG&E acknowledges and appreciates the Phase 1 Scoping Memo's wisdom in providing the assigned ALJ the latitude to modify the envisioned schedule "as required to promote the efficient and fair resolution of the rulemaking,"[3] PG&E remains concerned that the current proceeding schedule, for both tracks, may be too compressed. PG&E cautions that quality should not be sacrificed by proceeding too fast to create, expand, and implement the envisioned rate design changes, to ensure these new efforts are cost-effective, feasible, and understandable by customers to support rollouts that can be both as affordable and well-accepted by customers as possible. PG&E supports a balanced approach to meeting the sense of urgency with an approach that also fosters collaboration.

For example, regarding Track A, the Phase 1 Scoping Memo currently does not direct Energy Division to form a working group to discuss income-graduated fixed charge issues. In fact, the Phase 1 Scoping Memo only set one workshop (held on November 29, 2022) to facilitate information sharing among the parties regarding the many complex and novel issues included in Track A. PG&E believes that multiple workshops and/or working group meetings are likely to be helpful during the period between December 2022 through early February 2023, to enable further, iterative information sharing that can better inform and streamline parties' preparation of proposals and testimony on income graduated fixed charges, currently due by March 17, 2023.[4] Iterative discussions are advisable given the large amount of new factual information that resulted from November 29 workshop, as well as to keep the door open for parties to potentially achieve consensus on as many issues as possible before developing their own proposals. In addition, parties should be allowed a meaningful amount of time to brief the numerous statutory construction questions Commission staff raised at the November 29

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[3] Phase 1 Scoping Memo, p. 8.

[4] During the November 29, 2022 Track A all-day workshop hosted by Energy Division on a range of issues relating to Income Graduated Fixed Charges, PG&E expressed its desire for additional workshops, including on income-graduated fixed charge *implementation* issues, possibly in mid-December 2022 and/or January 2023.

workshop to allow reasonable protection of due process interests before reaching conclusions on such important threshold legal questions.[5]

Regarding Track B, PG&E has similar concerns. PG&E agrees that Track B's initial effort for updating rate design principles and determining new demand flexibility guidelines are threshold issues that will lay the foundation for the CPUC and stakeholders to create and implement rate reforms and programs that can most reasonably help further move towards achieving California's energy and climate goals.

During the RDP Workshop, many parties expressed concern about the lack of definitions for terms and general ambiguity of the rate design principles and demand flexibility guidelines. Energy Division signaled that it wanted to leave some items general, so that items could be further defined by the Commission and relevant proceeding records. However, following parties' respective filings of these opening and reply comments, prior to the issuance of a proposed decision on updated RDPs and for administrative efficiency, it may be beneficial to gather interested stakeholders one more time to attempt to seek consensus about whether a single set of agreed terms and definitions might be achieved. Furthermore, PG&E believes a final CPUC decision on these threshold issues is needed before the rest of Track B's explorations begin (currently set for Q2 2023). Ideally, a final CPUC decision on rate design principles and demand flexibility guidelines would be helpful shortly before kicking off Track B.

Moreover, expanding the B-6, B-20, and E-ELEC pilot rates and/or the DAHRTP-CEV opt-in rate (all of which are PG&E-billed) to additional rate classes before the summer of 2024, may be infeasible for PG&E due to our ongoing billing system backlog, which will be exacerbated once Net Energy Metering 3.0 final decision is issued.

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5 As two examples: (1) a minimum of two weeks' notice would be needed to allow parties to conduct proper statutory construction analyses and prepare opening briefs, with (2) a similar minimum amount of time for reply briefs, with the deadlines ideally also taking into account the December holidays.

A. [Phase 1 Scoping Memo Question No. 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 (see Attachment)? Why or why not?*

Yes, with minor revisions (detailed below), the Commission should adopt the staff proposal for modifying the electric rate design principles that the CPUC will apply to all electric rate making for the large investor-owned electric utilities (IOUs). Adopting PG&E's modifications will likely result in: (a) greater simplicity, clarity, and specificity in the updated rate design principles; (b) better alignment of CPUC rate design decisions with state policy goals; and (c) better support of a more positive customer experience that can more effectively encourage customer adoption of electrification technologies to further support California's decarbonization energy policy goals. PG&E provides, in Attachment A hereto, our proposed targeted modifications to the staff proposal of electric rate design principles (RDP), in redline format, for Commission consideration and adoption.

First, PG&E modifies staff's recommendations on **RDP Nos. 3, 4, and 5** to further simplify/clarify and make them more specific such that it better encourages customer action. Wherever staff's proposed revisions to the existing RDP language is vague, its call to action is similarly unclear. Specifically:

- Staff's proposed revisions to **RDP No. 3** seem vague and overbroad because it lacks definition. PG&E's proposed modification adds clarification regarding technology, geography, and customer classes to acknowledge that actual conditions differ amongst California's residential IOU customers. PG&E's proposed revision also accounts for cost-shifts that could result in either added costs or savings (as rate design is a zero-sum game).
- **RDP No. 4,** as recommended by staff, newly includes the phrase "beneficial electrification," a term that appears to be undefined and therefore could be unclear. During the RDP workshop, Energy Division staff explained that it had lifted this term from California Assembly Bill (AB) 205. However, in the context

of the CPUC's RDPs, it is unclear what action to undertake or metric to use that would consistently carry out the policy objectives underlying the use of the term "beneficial electrification." PG&E proposes a minor modification to clarify that vagueness by referring instead, more descriptively, to *"electrification that achieves decarbonization and cost-effective energy efficiency."* This minor modification should provide the needed specificity in order to better inform effective action.

- Finally, PG&E's recommended revision to staff **RDP No. 5** also results in greater clarity and includes reducing coincident and non-coincident peak demand and shifting demand to non-peak hours.

Second, PG&E recommends modifications to **RDP Nos. 4, 7 and 9** so that they better align with state goals, statutes, and Commission policy. As with the above clarification to **RDP No. 4**, these further modifications are needed to better reflect to goals of AB 205. PG&E agrees that it is time to update the rate design principles to expressly include decarbonization, in addition to energy efficiency and conservation, because **RDP No. 4's** original wording predated adoption of our state's current decarbonization policy and does not assume an ever-cleaner grid that will eventually be 100% renewable. California's current policy vision is designed to (1) make it greenhouse gas (GHG) friendly for a customer to use more electricity to power their appliances, (2) substitute new technologies using ever-cleaner electricity in place of older fossil fuel-based technologies to decarbonize both California's built environment –which represents about 25 percent of California's GHG profile -- and our state's transportation sector – which accounts for another approximately 40 percent of California's sources of greenhouse gas emissions.[6] For **RDP No. 7,** PG&E adds a layer of transparency to align with Commission

[6] *See, e.g.*, state data from the California Air Resources Board at https://ww2.arb.ca.gov (building decarbonization). See also, California Energy Commission on "Transforming Transportation" stating that, by some calculations, transportation accounts for almost 50 percent of our state's greenhouse gas emissions (https://www.energy.ca.gov/about/core-responsibility-fact-sheets/transforming-transportation)

policy and to fold in **RDP No. 8**. Further, PG&E's improvement to **RDP No. 9** better reflects state policy and the importance of cost-effectiveness of programs for affordability.[7]

Third, PG&E recommends modifications to **RDP Nos. 6 and 10** to support a positive customer experience that encourages them to act. For example, PG&E strongly urges the CPUC to re-insert the phrase "customer understanding" which staff suggested cutting from **RDP No. 6**. During the RDP workshop, multiple parties questioned why "customer understandability" was removed since (1) understandability has been a core principle dating back to the Bonbright rate design principles (upon which the CPUC heavily relied in developing its own RDPs),[8] and (2) remains an important consideration that should be taken into account in all rate design decisions (i.e., these RDPs will apply to all ratemaking, not solely toto demand-flexibility related rate design, for rates that are expected to be selected by some, but not all, customers). Staff explained that, while they still feel customer understandability is a key factor, they believe this concept is somehow layered into and included in *other* rate design principles. Respectfully, PG&E does not see how "understandability" can be deleted here and somehow be implicitly assumed (without express mention) to be included elsewhere in the RDPs. It is important that the RDPs continue to explicitly name customer understandability as a core consideration to be

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7 During the RDP Workshop, several parties stressed the importance of cost-effectiveness in the rate demand principles and demand flexibility guidelines.

8 In his seminal work, "Principles of P.U. Rates," James C. Bonbright (Columbia University Press, 1961) stated that the overarching goal of rate design is to promote efficient use of energy (by being cost-based), and that the key attributes for any rate are that to the greatest degree possible it must be: simple, understandable, feasible to implement, free from controversy in interpretation, stable (or to otherwise address cost volatility), fairly apportion cost of service among different customers/classes, and avoid undue discrimination among similarly-situated customers. Under the CPUC's current RDPs principles, which have always included "understandability," the CPUC has adopted default residential TOU rates as well as more sophisticated, specialized rates like electrification rates and day ahead hourly real-time pricing pilot rates. Understandability considerations did not impede such important efforts; rather, the CPUC looked at whatever customer surveys and feedback were available and often started out with pilots that would provide relevant information about customer response to inform and help refine such rates to ensure a more successful wide-scale roll-out. It has long been recognized that when the CPUC's ten RDPs come into conflict with one another, the CPUC weighs the evidence to strike a reasonable balance based on the record before it. But that record should continue to include some assessment of understandability, to ensure that even more complex optional rates are understandable as possible for customers so they more effectively help achieve state policy goals.

weighed in designing any kind of rate. For example, even more complex rates like opt-in electrification rates or real time pricing pilots need to be designed to be well-enough understood by customers so that they will adopt the rate and be able to respond to its price signals by shifting their usage to lower cost/lower GHG hours of the day. In other words, a reformed rate's price signal, though it might align with cost-causation and economic efficiency, might *not* be able to achieve the full range of state policy goals without adequate customer understandability because customer load shifting action is required for such rates to "work." For **RDP No. 10**, PG&E replaces the term "minimize" with "mitigate" to alleviate customer confusion as there may be occasions where a rate design reduces customers' bills for certain uses and appropriately increases bills for other uses.

Lastly, PG&E does not, at this time, recommend modifying either **RDP Nos. 1 or 2**. PG&E recommends folding **RDP No. 8** into **RDP No. 7**, but absent that change, PG&E would recommend leaving **RDP No. 8** as proposed by staff in the Phase 1 Scoping Memo.

B. [Phase 1 Scoping Memo Question No. 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 (see Attachment)? Why or why not?*

Yes, with PG&E's minor modifications, described below, the Commission should adopt its staff's proposed new demand flexibility guidelines (attached to the Phase 1 Scoping Memo), that would be applicable to all demand flexibility rate proposals for California's IOUs. PG&E's recommended modifications add needed specificity yet also maintain flexibility for the ultimate outcome of this, or other future proceedings, to guide specific proposals for demand flexibility rates and programs.

PG&E's proposed modifications add further clarification to the demand flexibility guidelines (DFG). Specifically, though minor, PG&E's proposed amendments to **DFG Nos. 2** and **6** help specify the types of solutions to be created in this rulemaking and future proceedings. In addition, our recommended modifications to **DFG No. 5** help underscore the fact that, for the mechanisms described, different treatment(s) may be needed for different customer classes. In addition, our modification reinforces the guideline that a measured, staged approach can be much better than trying to offer all mechanisms at once (or within an overly compressed timeframe).

PG&E does not, at this time, recommend any modifications to staff's proposals for **DFG Nos. 1, 3 and 4**, but reserves it right to do so, if warranted, in our January 2023, reply comments.

C. [Phase 1 Scoping Memo Question No. 3] *How should the Commission support the implementation of the amendments to the California Energy Commission's Load Management Standards?*

At this time, it seems premature to determine how the Commission should support the implementation of the amendments to the California Energy Commission's (CEC) Load Management Standards (LMS). At a minimum, there would need to be some level of continued or increased coordination between the CEC and the CPUC where: (1) the LMS and the demand flexibility guidelines overlap, and (2) CPUC guidance appears to conflict with provisions of the CEC's amended LMS. For example, PG&E's current, CPUC-approved RTP pilots,[9] do not align 100 percent with the subsequent provisions that the CEC's LMS recommends be considered by the CPUC in future exercises of its ratemaking jurisdiction over IOUs.

PG&E respectfully recommends the CEC and CPUC work together to efficiently manage: (1) the implementation of the revised LMS requirements and pre-requisites, and (2) the outcomes and implementation outcomes from R.22-05-002 and resulting future IOU applications, on a coordinated basis. In addition, there may be other Commission proceedings, such as the new R.22-11-013 on distributed energy resources (DER),[10] which includes data access and use issues, as well as cost effectiveness issues, with cross-over to both the LMS and R.22-07-005. This new DER rulemaking is an additional Commission proceeding for which

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9 *See* PG&E's Post-PHC Statement (Sept. 27, 2022), p. 2 and Attachment B.

10 R.22-11-013 describes distributed energy resources as follows, ". . . program offerings have expanded to include many different distributed energy resources (DER), including demand response, customer-sited generation and storage, smart grid technologies, and water-energy savings measures, and innovative rate design." R.22-11-013, p. 4. R.22-11-013 acknowledges the need to coordinate with the CEC, "Collaboration with the CEC throughout the course of the proceeding is anticipated to be particularly important for data-related issues discussed in Track 2." *Id.* pp. 10-11.

coordination with the CEC LMS implementation associated with the IOUs' approved plans under LMS, is likely to be necessary and beneficial.

PG&E reserves the right to comment further on this topic in our January 2023 reply comments.

1. [Phase 1 Scoping Memo Question No. 3, subpart (a)] *When and how should the large investor-owned utilities be required to file applications for approval of compliant rates?*

Like the IOUs' General Rate Case (GRC) Phase II applications, the IOUs should be required to file applications for approval of compliant rates, on a staged basis. Not only do marginal costs vary by IOU, but so do operational constraints relating to implementation; in the past, IOU-specific applications (like PG&E's RTP track within its last GRC Phase II) have included our best early estimates of likely implementation costs (as well as requests for provision of recovery of actual incremental costs recorded in a balancing or memo account, if and as appropriate, subject to reasonableness review once actual costs are known). Given the complexity of the whatever IOU programs and rates relating to demand flexibility, future such IOU-specific rate design proceeding will likely involve similar stakeholders. Therefore, staged or staggered applications could lessen the strain on resources, reduce confusion, and have greater efficiency.

2. [Phase 1 Scoping Memo Question No. 3, subpart (b)] *Are there any existing investor-owned utility tariffs or pilot rates that comply with the requirements for a dynamic, marginal cost-based rate?*

Based on the CEC's amended LMS requirements for a dynamic marginal cost-based rate, expected to become effective in April 2023, and the current pipeline of real time pricing rates, three of CPUC-approved rates may be likely to meet the LMS requirement within PG&E's service territory:

- the Valley Clean Energy (VCE) Agriculture RTP pilot (already in place for seven customers), and
- the two Vehicle Grid Integration (VGI) pilot rates that are expected to become available for customer enrollment in the Summer of 2023.

In addition, PG&E has other marginal cost-based dynamic rates that, while they comply for the most part with the CEC LMS's requirements, have already been adopted by the CPUC without the dynamic distribution component subsequently mentioned by CEC in its recently released amended LMS standard expected to become effective in April 2023. PG&E's additional dynamic rates include the following:

- Small Commercial RTP Pilot rate on Schedule B-6,
- Large Commercial RTP Pilot rate on Schedule B-20,
- Residential Electrification RTP Pilot rate (on the new Electric Home rate, which is the customer-facing name for Schedule E-ELEC as referred to in CPUC decisions and tariffs),[11]
- Opt-in Day-Ahead Real Time Pricing rate for Commercial Electric Vehicles on Schedule BEV,[12] and the related
- PG&E's cost-based Commercial Electric Vehicle Non-NEM Export Compensation Pilot Rate designed to sit on top of our DAHRTP-CEV rate, listed above.[13]

PG&E highlights that there is no limitation to the number of customers that can enroll on the Small Commercial, Large Commercial, Residential and BEV RTP rates.

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[11] All three of PG&E's newest RTP rate pilots were adopted in D.22-08-002, in which the CPUC approved an uncontested all-party settlement that resulted from over a year of arms-length negotiations among a wide array of diverse parties and interests. These pilots were expressly referred to as "Stage 1" with an envisioned later "Stage 2" after final reported results from Stage 1, to consider modifications and scope expansion. In addition to leveraging final pilot data reporting, Stage 2 was to be informed by approved customer surveys of dynamic pricing preferences of PG&E's Agricultural, Residential, as well as Small Business customers, which are currently underway.

[12] The CEV DAHRTP rate was adopted by the CPUC in D.21-11-017.

[13] The CEV Non-NEM Export Compensation pilot rate was adopted in D.22-10-024, approving an uncontested all-party settlement.

D. [Phase 1 Scoping Memo Question No. 4] ***Should the Commission expand any of the existing dynamic rate pilots as a near-term solution to benefit system reliability?***

At this time and subject to other considerations identified below, PG&E is open to the Commission starting to consider potentially expanding some of our already-approved existing dynamic rate pilots (VGI, B-6, B-20, and Electric HOME), if doing so might provide "near-term solution to benefit system reliability." Within PG&E's service territory, the rate pilot expansions that can possibly contribute to near-term system reliability are (a) expanding the VCE pilots (because they use shadow billing), and (b) expanding the number of community choice aggregators (CCAs) that may participate in PG&E's existing RTP rate pilots, listed above.[14]

Any expansion would need to be thoughtful, feasible, and cost-effective to implement. As stated in PG&E's prior written and oral comments in this proceeding, these pilots are expected to provide valuable information about customer response to dynamic price signals, including data evaluation on customer load response and other customer feedback, cost results, testing of feasibility of implementation, and other practical lessons learned.[15] Analysis of the early years of these pilots' operations is an essential input to further inform whether such pilots should be expanded, and if so how, and whether any modifications are warranted to improve results.

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[14] PG&E recognizes that the revised LMS adopted by CEC in September are applicable to Community Choice Aggregators. PG&E is not commenting on any implications that may related to CCA participation in PG&E pilots, due to the LMS.

[15] *See generally*, Comments of Pacific Gas and Electric Company in Response to Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates (Aug. 15, 2022); Joint Comments of California Farm Bureau Federation, California Large Energy Consumers Association, California Manufacturers & Technology Association, Energy Producers and Users Coalition, Energy Users Forum, and Federal Executive Agencies on the Order Instituting Rulemaking (Aug. 15, 2022); Reply Comments of Pacific Gas and Electric Company in Response to Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates (Aug. 25, 2022); Joint Reply Comments of the California Large Energy Consumers Association, California Manufacturers & Technology Association, The Energy Producers and Users Coalition, Energy Users Forum, and Federal Executive Agencies (Aug. 25, 2022); Prehearing Conference transcript (Sept. 16, 2022); Pacific Gas and Electric Company Post Pre-Hearing Conference Statement (Sept. 27, 2022).

1. **[Phase 1 Scoping Memo Question No. 4, subpart (a)]** ***If so, which pilots should the Commission expand and why?***

See PG&E's response in Section D and D.2.

2. **[Phase 1 Scoping Memo Question No. 4, subpart (b)]** ***How should any of the expanded pilots be modified (e.g., duration, size, eligibility criteria, reporting/evaluation requirements, rate design, cost recovery)?***

Final, vetted pilot data is not yet available because (1) one of the already-approved RTP pilots has been launched but is still incomplete, and (2) other pilots have not yet launched. Therefore, PG&E's response to this question is subject to change in the future. As mentioned above, in the event the Commission were to decide to expand some or all the existing RTP pilots, PG&E respectfully requests that additional guidance be provided regarding the duration, enrollment criteria/scope, eligibility criteria, reporting/evaluation requirements, rate design, cost recovery, and regulatory mechanisms that would apply to any such expansions.

At a minimum, one method for potentially modifying the identified, already-approved RTP pilots could be to expand them to include bundled and other CCAs' customers. Regarding the VCE pilot, PG&E would be open to Commission consideration of increasing the megawatt cap, replicating a VCE-type pilot in other geographic areas to allow bundled and other CCAs' customers to participate (to the extent permissible, if at all, under CCA-related laws), and increasing the budget for automation incentives and systems/technology to support the increased scale.

To date, no CCAs within PG&E's territory have committed to participate in our B-6, B-20, and Electric Home RTP pilots, but we have requested a decision from them by January 15, 2023. PG&E hopes the CPUC, CEC, and others will encourage one or more CCAs to elect to participate in PG&E's three already-approved RTP pilots. These initial efforts will see expanded participation size, with greater reach to help effect the State's overall energy policy goals. Over 60 percent of PG&E's electric customers take their generation service from one of twelve CCAs in our service territory, so it would not seem possible to achieve the state's goals using demand flexibility rates that only apply to 40 percent of PG&E's customers.

PG&E anticipates any expansion of already-approved RTP pilots, involving rate design modifications, will almost certainly require increased marketing and education budgets and recovery of additional, incremental implementation costs beyond those previously authorized.

Moreover, because PG&E's approve RTP pilot rates for B-6, B-20 and Electric Home (E-ELEC) and/or our DAHRTP-CEV opt-in rate, are PG&E-billed,[16] expansion to additional rates or rate classes before 2026 may be infeasible for PG&E. This is due to an ongoing billing system backlog, which is expected to be exacerbated by the CPUC impending final decision on NEM 3.0.

E. [Phase 1 Scoping Memo Question No. 5] ***Beyond the six-element California Flexible Unified Signal for Energy (CalFUSE) policy roadmap [Footnote omitted] 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?***

PG&E views this current proceeding as the CPUC's forum for initial consideration of proposals for marginal cost-based demand flexibility rates in support of the LMS – whether hourly or with some other time interval and whether they include some or all of the rate components mentioned in the CalFUSE policy roadmap. Although the updated CEC LMS standards, when they become effective (expected April 2023), will require that hourly marginal cost-based rates eventually be available for *all* customer classes, PG&E does not believe that there should be a presumption at this time that some other form of dynamic rates might not be more effective for some customer classes at achieving the desired load flexibility objectives necessary to meet California's decarbonization goals.

[16] As opposed to "shadow-billed" pilots that do not affect PG&E's billing system.

Notwithstanding the above, as PG&E discussed in Section C, it seems similarly premature to try to determine at this time what alternate proposals might be possible, or that the Commission should consider, to enable widespread implementation of the CEC LMS by IOUs and for third party providers. PG&E agrees with the Phase 1 Scoping Memo's call for such issues not to be taken up before Q2 2023, as part of Track B. However, PG&E reserves the right to provide further response in our January 2023 reply to others' comments on this point.

III. CONCLUSION

PG&E appreciates the opportunity to submit these opening comments to the questions in the Phase 1 Scoping Memo. PG&E looks forward to continuing to work collaboratively with the CPUC and all parties on Demand Flexibility initiatives that expected to help California achieve our climate action goals.

Respectfully submitted,

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ATTACHMENT A

PROPOSED MODIFICATIONS TO THE RATE DESIGN PRINCIPLES AS REVISED IN THE PHASE 1 SCOPING MEMO AND RULING

This Appendix includes PG&E's proposed modifications to the Rate Design Principles as revised in the Phase 1 Scoping Memo and Ruling. As described in PG&E's opening comments, PG&E recommends the Commission adopt the Revised Rate Design Principles with PG&E's modifications.

For completeness, PG&E includes the current principles in black text below, while the revised principles are in **blue-boldface** text. PG&E omits the footnotes and justification for proposed changes in blue text that are included in the Phase 1 Scoping Memo and Ruling**.**

PG&E provides its additions in ***bold italics***. Deletions are in ~~**strikethrough**~~.

1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.

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

2) Rates should be based on marginal cost.

   Rates should be based on marginal cost and should not have a negative Contribution to Margin.

3) Rates should be based on cost-causation principles.

Rates should be based on cost-causation principles and avoid *non-cost-based* cost shifts *both within (due to technology or lack of same, geography, etc.) and among customer classes*.

4) Rates should encourage conservation and energy efficiency.

Rates should encourage greenhouse gas emissions reduction, ~~beneficial electrification~~ *electrification that achieves decarbonization* and cost-effective energy efficiency.

5) Rates should incentivize reduction of both coincident and non-coincident peak demand.

Rates should *minimize long-term grid capacity expansion costs to optimize the use of* existing grid infrastructure ~~and limit long-term infrastructure costs~~.

6) Rates should be stable and understandable and provide customer choice.

Customers should have *rate* options *that are understandable and should include mechanisms that enable them* to manage their bills. *Rate design should be guided by customer research.*

7) Rates should avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.

Rates should be technology-neutral and avoid cross-subsidies, unless the cross-subsidies *are transparent and* appropriately support explicit state policy goals.

8) Rate incentives should be explicit and transparent.

Rate incentives should be explicit and transparent.

PG&E note: If the Commission adopts **RDP No. 7** with PG&E's modifications above, then PG&E recommends deletion of **RDP No. 8** as duplicative. However, if the Commission does *not* adopt PG&E's recommended modifications to **RDP No. 7**, then PG&E supports leaving **RDP No. 8** as proposed by Energy Division staff in the Phase 1 Scoping Memo.

9) Rates should encourage economically efficient decision making.

Rates should encourage customer behavior that improves system reliability *in an economically efficient manner*.

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

Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding ~~and acceptance of new rates~~ and ~~minimizes~~ *mitigates* ~~the~~ bill impacts associated with such transitions.

ATTACHMENT B

PROPOSED MODIFICATIONS TO THE DESIGN FLEXIBLE GUIDELINES AS REVISED IN THE PHASE 1 SCOPING MEMO AND RULING

This Appendix includes PG&E's proposed revisions to the Demand Flexible Guidelines as revised in the Phase 1 Scoping Memo and Ruling. For completeness, PG&E includes the proposed Guidelines are in black text below; PG&E omits the footnotes and justification for proposed changes originally in blue text as included in the Phase 1 Scoping Memo and Ruling.

PG&E provides its additions in ***bold italics***. Deletions are in ~~strikethrough~~.

1. Demand flexibility tariffs should provide a dynamic price signal that can be easily integrated into standardized third-party DER and demand management solutions.

2. Dynamic prices should accurately integrate the value of energy, generation capacity, distribution capacity, and transmission capacity (to the extent feasible) based on ***forecasted day-ahead and/or*** real-time grid conditions.
3. The systems & processes needed to calculate the dynamic price signal should be able to integrate bundled and unbundled rate components so that all Load Serving Entities can elect to participate.

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

   PG&E Note: PG&E suggests moving this to the front of the list to be a general, overarching guideline.

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. ***Not all features may be appropriate for all customer classes. Mechanisms can be rolled out over time so that more complicated features are included after customers become***

familiar with demand flexibility.

6. Demand flexibility tariffs should provide accurate ***marginal*** cost-based compensation for exports that supports customer investments in electrification technologies and DERs.