Application: 22-05-002
(U 39 E)
Exhibit No.: (PG&E-8)
Date: May 12, 2023
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023-2027 DEMAND RESPONSE PROGRAMS, PILOT, AND BUDGETS

2024-2027 FULL PROPOSAL

REBUTTAL TESTIMONY

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CHAPTER 1

REBUTTAL TESTIMONY OF

JOHN C. HERNANDEZ, NEDA ASSADI,[1] JOMO THORNE, BRAD WETSTONE, AND JOHN LIN

PROGRAM POLICY ENHANCEMENTS

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A. Introduction

Q 1 What is the purpose of this rebuttal testimony?

A 1 This testimony responds to the direct testimony of the Public Advocates Office of the California Public Utilities Commission (Cal Advocates),[1] California Efficiency + Demand Management Council (CEDMC),[2] California Large Energy Consumers Association (CLECA),[3] Joint Community Choice Aggregators (JCCA),[4] OhmConnect,[5] and Sierra Club.[6] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below.

Q 2 What issues are included in PG&E's prepared testimony on Program Policy Enhancements?

A 2 PG&E's prepared testimony on Program Policy Enhancements includes recommendations on the following issues:

- Load Flexibility, Market Integration Efficacy, and Market Potential Studies;
- Dual Participation;
- Auto Enrollment of Participants Receiving Technology Program Incentives;
- Prohibited Resources (PR);
- Emergency Demand Response Cap;
- Program Enhancement Flexibility; and

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1 Cal Advocates-2.

2 CEDMC-2.

3 CLECA-2.

4 JCCA-1.

5 OhmConnect-2.

6 Sierra Club-1.

- Report Summaries of the Retail Baseline Working Group, Disadvantaged Communities Demand Response Pilot, and Customer Information Working Group.

B. Summary of Parties' Positions

Q 3 Do parties support any of PG&E's Program Policy Enhancements in their direct testimony?

A 3 Yes, the following parties support PG&E's Program Policy Enhancements:

- CLECA and CEDMC support PG&E's proposed Market Integration Efficacy Study;[7]
- Cal Advocates, CEDMC, CLECA, and JCCA support PG&E's recommendation to revisit dual participation rules;[8]
- Enchanted Rock supports PG&E's recommendation to temporarily suspend PR restrictions for the Base Interruptible Program as long as the resources meet the California Air Resources Board (CARB)-DG certification requirements for local emissions and run on California Energy Commission (CEC) Renewables Portfolio Standard-certified and/or CARB Low Carbon Fuel Standard Pathway certified renewable fuels;[9]
- CLECA supports PG&E's recommendation to extend the increase in the emergency reliability cap at three percent.[10] No parties oppose this proposal; and
- CLECA supports PG&E's recommendation to increase program enhancement flexibility;[11]

Q 4 Do parties provide any recommendations regarding PG&E's Program Policy Enhancements?

A 4 Yes, the following parties provide recommendations on Program Policy Enhancements below:

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7 CLECA-2, p. 14, line 19 to p. 15, line 14; CEDMC-2, p. 5, line 14 to line 15.

8 Cal Advocates-2, Chapter 2, p. 2-3, line 16 to line 20; CEDMC-2, p. 12, line 5 to line 7; CLECA-2, p. 31, line 10 to line 11; JCCA-1, p. 4, line 13 to line 23; CLECA-2, p. 26, line 9 to line 12; CLECA-2, p. 4, line 14.

9 Enchanted Rock-1, p. 5, line 5 to line 8.

10 CLECA-2, p. 26, line 7 to line 12.

11 CLECA-2, p. 4, line 14.

- CEDMC provides recommendations on PG&E's Proposed Market Integration Efficacy Study;
- Cal Advocates provides recommendations on PG&E's proposed Load Flexibility Study;
- JCCA and OhmConnect provide recommendations on dual participation;
- Cal Advocates provides recommendations on PG&E's proposal to automatically enroll customers receiving technology incentives into Demand Response (DR) programs; and
- Cal Advocates and Sierra Club oppose PG&E's recommendations on PRs;
- Cal Advocates and CEDMC provide recommendations on PG&E's proposal to increase program enhancement flexibility.

Q 5 Do you dispute any of the parties' recommendations regarding Policy Program Enhancements?

A 5 Yes, we address parties' recommendations in Section C.

Q 6 Do parties provide any new program policy recommendations not included in PG&E's direct testimony?

A 6 Yes, the following parties provide new recommendations:

- CEDMC requests that the California Public Utilities Commission (CPUC or Commission) allow DR providers the flexibility to contract out their capacity as Reliability Demand Response Resources (RDRR) or as load modifying DR;[12]
- OhmConnect requests that the Commission require the investor-owned utilities (IOU) to provide customer usage data to third parties within 48 hours.[13]

Q 7 Do you dispute any of the new program policy recommendations made by parties?

A 7 Yes, we address parties' recommendations in Section D.

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[12] CEDMC-2, p. 10, line 21 to line 25.

[13] OhmConnect-2, p. 26, line 3 to p. 28, line 8.

C. PG&E's Response to Parties' Recommendations Concerning PG&E's Program Policy Enhancements

1. Market Integration Efficacy Study (Witness: John C. Hernandez)

Q 8 What is the Market Integration Efficacy Study proposed by PG&E?

A 8 The Market Integration Efficacy Study aims to determine whether DR market integration is a more effective mechanism to support the state's clean energy policy, whether the Commission's goals for DR market integration have been achieved, and what changes to policies, rules, or processes should occur to make DR a more useful resource.[14] PG&E recommends that an advisory committee provide input on the study's direction and serve as points of contact for the study's consultants to request data.[15] PG&E proposes to co-fund the study with the other IOUs at a total cost of $3 million, with PG&E's portion ($1.2 million) funded through its Demand Response Emerging Technology (DRET) Program.[16]

Q 9 Which parties recommend modifications to PG&E's Market Integration Efficacy Study?

A 9 CEDMC cautions the Commission to preserve optionality for DR participants and third parties to deliver load modifying and/or supply resource DR regardless of the study's results and recommends that the Commission include representatives of residential and non-residential DR participants as well as third-party DR providers.[17]

Q 10 Do you agree with CEDMC's proposed modifications?

A 10 Yes, PG&E agrees with CEDMC's proposal to include representatives of residential and non-residential DR participants as well as third-party DR providers on the advisory committee for the Market Integration Efficacy Study.

2. Load Flexibility Study (Witness: Neda Assadi)

Q 11 What is the Load Flexibility Study proposed by PG&E?

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14 Exhibit (PG&E-2), Chapter 2, p. 2-8, line 1 to line 5.

15 Exhibit (PG&E-2), Chapter 2, p. 2-8, line 10 to line 14.

16 Exhibit (PG&E-2), Chapter 2, p. 2-8, line 7 to line 10.

17 CEDMC-2, p. 5, line 15 to p. 6, line 9.

A 11 The Load Flexibility Study aims to identify and disaggregate end-use loads that are sizeable and flexible enough to help address operational and planning needs, and to determine if these loads can be managed through existing programs or, if not, through new or enhanced programs. Specifically, the Load Flexibility Study aims to:

- Understand customer elasticity by end-use;
- Identify usage patterns of specific behind-the-meter (BTM) distributed Energy Resources (DER) and smart appliances that can help improve customer load elasticity;
- Determine how the load-reduction and flexibility potential of these devices could be optimally leveraged via the strategic deployment of BTM DER and smart appliances enabling technology;
- Develop a supply curve of end-use loads that can be leveraged at each hour of the peak; and
- Convert learnings into actionable program design and/or operational insights.

PG&E proposes to co-fund the study with the other IOUs at a total cost of $3 million, with PG&E's portion ($1.2 million) funded through its DRET Program.[18]

Q 12 Which parties recommend modifications to PG&E's Load Flexibility Study?

A 12 Cal Advocates recommends that the Commission direct PG&E to provide results on the dollar amounts that are required to incentivize representative customer groups to participate in a variety of DR programs.[19]

Q 13 Do you agree with Cal Advocates' proposed modifications?

A 13 Yes, PG&E agrees with Cal Advocates' recommendation to explore the inclusion of dollar amounts needed to incentivize participation.

3. Dual Participation (Witness: Neda Assadi)

Q 14 What is PG&E's proposal related to dual participation?

A 14 PG&E explains that existing dual participation rules are neither complete nor contemplate increasing complexity.[20] For example, the CPUC's dual

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18 Exhibit (PG&E-2), Chapter 2, p. 2-6, line 27 to line 30.

19 Cal Advocates-2, Chapter 2, p. 2-2, line 8 to line 11.

20 Exhibit (PG&E-2), Chapter 2, p. 2-8, line 32 to p. 2-9 line 1.

participation rules were developed in the context of load-modifying DR programs, however, there is increasing shift towards market-integrated DR, including the California Independent System Operator's (CAISO) governance of additional dual participation rules.[21] As a result, PG&E recommends that the Commission establish workshops to help stakeholders develop a common understanding of existing CPUC and CAISO dual participation rules and policies and to initiate establishment of principals and goals for dual participation.[22]

Q 15 Do parties support PG&E's proposal on dual participation?

A 15 Yes, Cal Advocates,[23] CEDMC,[24] CLECA,[25] and CalCCA[26] support PG&E's proposal for the Commission to initiate workshops to discuss revisions to the dual participation rules. Cal Advocates and CEDMC agree that a workshop will help to discuss complexities in dual participation today,[27] and CalCCA agrees with PG&E's testimony that the dual participation rules are outdated and should be updated.[28] No parties opposed the request to initiate workshops.

Q 16 Which parties recommend modifications to PG&E's proposal on dual participation?

A 16 JCCA recommends that the Commission direct the development of a streamlined process to ensure Community Choice Aggregators (CCA) and PG&E regularly exchange program participation data and effectively prevent double counting customer load reductions.[29] In addition, JCCA recommends that PG&E unenroll customers already participating in a CCA load modifying DR program from the Emergency Load Reduction Program

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21 Exhibit (PG&E-2), Chapter 2, p. 2-9, line 5 to line 9.

22 Exhibit (PG&E-2), Chapter 2, p. 2-9, line 10 to line 14.

23 Cal Advocates-2, p. 2-3, line 6 to line 9.

24 CEDMC-2, p. 12, line 5 to line 13.

25 CLECA-2, p. 31, line 10 to line 11.

26 JCCA-1, p. 1, line 9 to p. 2, line 2, p. 4, line 13 to line 23.

27 Cal Advocates-2, p. 2-3, line 6 to line 9; CEDMC-2, p. 12, line 5 to line 13.

28 JCCA-1, p. 1, line 9 to p. 2, line 2, p. 4, line 13 to line 23.

29 JCCA-1, p. 5, line 17 to line 20.

(ELRP) or other PG&E load modifying DR program within five days of receiving program participation data from the CCA.[30]

Q 17 Do you recommend that the Commission adopt JCCA's recommendations?

A 17 No. Although PG&E believes that regularly exchanging program participation data may help prevent dual participation issues such as double-counting/compensation and improve the customer experience, PG&E recommends that the Commission deny JCCA's recommendations at this time because there are outstanding questions related to JCCA's proposal that require refinement. For instance, PG&E requires customer consent to disenroll customers from its DR programs to comply with existing tariff and program design. Moreover, customers need to decide and know which programs they want to use, rather than enduring automatic disenrollment, potentially without their prior knowledge, from programs in which they have been participating. In addition, JCCA's proposals appear to create inconsistencies with the Commission's process for competitive neutrality, which requires CCAs to submit a Tier 3 advice letter stating that an IOU offers a similar program to theirs, and upon approval, provides for a year-long process to unenroll the customer and offer a credit to CCA customers.[31]

To adequately address these concerns, PG&E recommends that the dual participation workshops proposed by PG&E provide an opportunity to further develop JCCA's proposals such that a complete proposal can be developed addressing policy, operations, and privacy issues comprehensively for IOU and CCA exchange program participation data, on a two-way basis. PG&E recommends that the complete proposals be served for the CPUC to determine if testimony is required before the Commission decides the issues presented in the proposals.

4. Auto Enrollment of Participants Receiving Technology Program Incentives (Witness: John C. Hernandez)

Q 18 What is PG&E's proposal related to auto enrollment of participants receiving technology incentives?

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[30] JCCA-1, p. 6, line 12 to line 15.

[31] See D.17-10-017 and Resolution (Res.) E-5008.

A 18 PG&E explains that there is an increasing number of programs that require customers to enroll in a DR program as a condition of receiving technology incentives (e.g. ADR, Self-Generation Incentive Program).[32] PG&E supports these initiatives and recommends that the Commission develop similar requirements for customers receiving other ratepayer-funded technology incentives, such as those available via energy efficiency, clean energy transportation, and distributed generation programs.[33]

Q 19 Which parties recommend modifications to PG&E's proposal on auto enrollment of participants receiving technology incentives?

A 19 Cal Advocates explains that while PG&E's proposal may be appropriate, the Commission should take care to consider the impacts and potential negative customer consequences before applying a blanket mandate.[34] Cal Advocates provides a hypothetical example of a medically vulnerable customer who receives a smart thermostat incentive through the Energy Savings Assistance Program to explain how this customer should not be forced to participate in an air conditioning control program that could result in serious health consequences.[35] Cal Advocates therefore recommends that the Commission host a workshop with impacted stakeholders prior to implementing PG&E's proposal.[36]

Q 20 Do you agree with Cal Advocates' proposed modifications?

A 20 Yes, PG&E agrees that there may be inadvertent consequences associated with auto enrollment of customers receiving technology incentives in a DR program and supports Cal Advocates' recommendation to further discuss implementation of this policy through a workshop. PG&E recommends that the workshop include interested parties from the service lists of relevant DER customer programs proceedings.

PG&E also notes that the Energy Division Staff is exploring PG&E's proposal through "Proposal D" in the Assigned Commissioner's Ruling

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[32] Exhibit (PG&E-2), Chapter 2, p. 2-11, line 2 to line 7.

[33] Exhibit (PG&E-2), Chapter 2, p. 2-11, line 9 to line 12.

[34] Cal Advocates-2, Chapter 2, p. 2-4, line 1 to line 3.

[35] Cal Advocates-2, Chapter 2, p. 2-4, line 3 to line 6.

[36] Cal Advocates-2, Chapter 2, p. 2-4, line 11 to line 12.

Directing Response to Questions and Energy Division Staff Proposals Related to Application (A.) 22-05-002 Phase II Issues (Phase II ACR). In that proposal, the Energy Division proposes a standardized definition of “qualified” DR programs that can be used when the Commission considers requiring customers to enroll in a DR program as a condition of receiving ratepayer-funded incentives or rebates.[37] PG&E believes that a standard definition of “qualified” DR programs is a useful first step towards implementing PG&E’s proposal and believes that a workshop would be helpful to further develop the appropriate use cases for this policy.

5. Prohibited Resources (Witness: Jomo Thorne)

Q 21 What is PG&E’s proposal related to PRs?

A 21 PG&E believes that the exemption for PRs established in Res.E-4906 requires clarification because it is unclear what the Commission intended when it states that “CARB-certified” fuels are exempt.[38] As explained in PG&E’s comments in response to the Phase II ACR, PG&E recommends that the Commission identify which specific CARB program and guidelines should be used to determine the fuels that are exempt from PR policy so that there is no ambiguity as to whether a specific fuel can be used to reduce load in DR programs.[39]

In addition, PG&E proposes that the Commission temporarily suspend PR restrictions for customers participating in the Base Interruptible Program (BIP) in 2024 and 2025.[40] PG&E believes that this proposal could increase the availability of emergency resources needed to help stabilize the grid and minimize the likelihood of rotating outages during extreme weather events.[41]

Q 22 Which parties recommend modifications to PG&E’s proposal on PRs?

A 22 Cal Advocates and Sierra Club recommend that the Commission reject PG&E’s proposal to temporarily suspend PR restrictions for BIP customers

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37 Phase II ACR, Appendix A, pp. 11-12.

38 Exhibit (PG&E-2), Chapter 2, p. 2-15, line 17 to p. 2-16, line 8.

39 PG&E’s Opening Comments on the Phase II ACR, pp. 17-18.

40 Exhibit (PG&E-2), Chapter 2, p. 2-16, line 10 to line 11.

41 Exhibit (PG&E-2), Chapter 2, p. 2-16, line 17 to 20.

in 2024 and 2025. Cal Advocates claims that any expansion of the use of fossil fuel backup generators in DR programs would have significant impacts on the health and well-being of Californians and that it is antagonistic to the state's energy goals to grow DR by incentivizing the dirtiest form of generation.[42] Sierra Club explains that the Governor can waive PR restrictions via Emergency Proclamation/Executive Order when there is imminent potential for loss of load service and that BIP covers a range of situations far more varied than the most extreme grid emergencies.[43] Sierra Club concludes that it would be dangerous for the Commission to reward businesses that reduce load in favor of diesel back-up generators when not absolutely necessary.[44]

Q 23 Do you agree with the recommendations from Cal Advocates and Sierra Club?

A 23 No, PG&E does not agree with Cal Advocates and Sierra Club that the Commission should deny PG&E's request to temporarily suspend PR restrictions for BIP in 2024 and 2025. PG&E understands that the increased use of diesel backup generators can have detrimental environmental and health impacts, especially in disadvantaged communities. However, there have been historic heat events in the last three summers, and each event has included Emergency Proclamations/Executive Orders from the Governor which suspended PR restrictions. PG&E believes that this recent history warrants the Commission to re-visit its PR policy with the dual goals of: (1) clearly defining and limiting instances when PRs can be used and (2) providing more certainty to DR participants regarding the use of PRs. PG&E believes that suspending PR restrictions for BIP in 2024 and 2025 supports both goals and provides an opportunity to assess whether the policy is achieving these goals prior to extending it for 2026 and 2027.

Q 24 Are there alternatives to suspending PR restrictions for BIP in 2024 and 2025 that would clearly define and limit instances when PRs can be used and provide more certainty to DR participants regarding the use of PRs?

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42 Cal Advocates-2, Chapter 3, p. 3-2, line 2 to line 4; p. 3-7, line 6 to line 8.

43 Sierra Club-1, p. 10, line 5 to line 12.

44 Sierra Club-1, p. 10, line 13 to line 14.

A 24 Yes, if the Commission chooses not to suspend PR restrictions for BIP, PG&E recommends that the Commission establish a policy which states that PRs can be used to achieve any load reduction during emergencies (not just incremental load reductions), only in response to an Emergency Proclamation or Executive Order from the Governor or President of the United States.

The Commission has similarly used Emergency Proclamations/ Executive Orders as the triggering event for utility response in the Emergency Disaster Relief Program Order Instituting Rulemaking (Rulemaking 18-03-011), which requires the IOUs to provide emergency customer protections in response to such declarations.[45] Under this approach, an Emergency Proclamation/Executive Order in response to a heat event would not need to identify which specific programs would be exempt from using PRs—it would only need to refer to the Commission's policy which suspends PR policy in response to an Emergency Proclamation/Executive Order.

In prior heat emergencies, PG&E has observed that the inclusion of PR waivers in Emergency Proclamations/Executive Orders has not been clear and required ad hoc coordination between the IOUs, Commission, and the Governor's Office to identify which programs could use PRs during an emergency. This has contributed to customer confusion and delayed response while obtaining clarifications during an emergency. For example, during the September 2022 heat event, the Governor originally did not specify in his August 31,2022 Emergency Proclamation which DR programs could use PRs to reduce load during emergencies.[46] A subsequent Executive Order on September 2, 2022 identified BIP and ELRP specifically.[47]

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45 D. 19-07-015, OP 1, p.63.

46 https://www.gov.ca.gov/wp-content/uploads/2022/08/8.31.22-Heat-Proclamation.pdf?emrc=78e3fc.

47 https://www.gov.ca.gov/wp-content/uploads/2022/09/9.2.22-Heat-Wave-EO.pdf?emrc=92d675.

PG&E believes that its proposed alternative would be more efficient and provide certainty to the IOUs and DR participants regarding when PRs can be used for load reduction before emergencies are declared.

In particular, PG&E recommends that the Commission include BIP, ELRP, and CBP as DR programs that would be exempt from PR restrictions in accordance with this policy. This approach would maximize the amount of load reduction available to support grid reliability during the most critical emergency situations.

6. Program Enhancement Flexibility (Witness: Jomo Thorne)

Q 25 What is PG&E's proposal related to program enhancement flexibility?

A 25 PG&E recommends that the Commission not require a mid-cycle review for the 2024-2027 program cycle and instead permit PG&E to submit an advice letter by December 1 for program changes that would be effective by May 1 of the following year.[48]

Q 26 Which parties recommend modifications to PG&E's proposal for program enhancement flexibility?

A 26 Cal Advocates recommends that the Commission retain the mid-cycle review for the 2024-2027 program cycle to assess whether DR pilots launched in 2024 should be continued for the rest of the cycle.[49] CEDMC also supports retaining the mid-cycle review as long as the Commission can dispose of the advice letters no later than five months following submission.[50] CEDMC recommends a mid-cycle review filing date of April 1, 2026 to allow for two years of experience in the 2024-2027 program cycle to inform any revisions for implementation in 2027.[51]

Q 27 Do you agree with the recommendations from Cal Advocates and CEDMC to retain the mid-cycle review for the 2024-2027 program cycle?

A 27 Yes, although PG&E originally opposed retaining the mid-cycle review process for the 2024-2027 program cycle, PG&E agrees with CEDMC that the mid-cycle review can provide a necessary tool to modify DR programs if

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48 Exhibit (PG&E-2), Chapter 2, p. 2-19, line 24 to p. 2-20, line 12.

49 Cal Advocates-2, p. 5-1, line 16 to line 17.

50 CEDMC-2, p. 11, line 13 to line 15, line 25 to line 26.

51 CEDMC-2, p. 11, line 26 to p. 12, line 2.

the changes can be approved in a timely fashion. As a result, PG&E would support retaining the mid-cycle review if the Commission is able to dispose of the mid-cycle review advice letters no later than five months following submission. Specifically, PG&E proposes that the mid-cycle review filing be due November 1, 2025, with approval from the Commission no later than April 1, 2026. PG&E believes that this is a more appropriate timeline than the proposal from CEDMC because it similarly allows for two years of program experience in the cycle but has the benefit of allowing changes to be implemented in time for the 2026 summer season.

D. PG&E's Response to Parties' New Recommendations Concerning Program Policy Enhancements

1. Competitive Parity (Witness: Jomo Thorne)

Q 28 What is CEDMC's proposal related to competitive parity?

A 28 CEDMC proposes that the Commission allow DR providers the flexibility to contract out their capacity as RDRRs or as load modifying DR.[52]

Q 29 What is the basis for CEDMC's proposal?

A 29 CEDMC claims that the IOUs have advantages over third-party DR providers, such as the ability for IOUs to designate their supply resource programs as RDRRs, which are dispatched far less frequently than Proxy Demand Response (PDR) because they are considered emergency programs.[53] CEDMC explains that DR providers must bid into the CAISO market as a PDR and do not have the same flexibility as IOUs.[54] In addition, CEDMC states that IOUs have the unique ability to transition their supply resource DR programs to load modifying programs, while DR providers do not.[55] Lastly, CEDMC claims that customers participating in IOU DR programs and the Demand Response Auction Mechanism (DRAM) are eligible for technology incentives, but customers participating in third-party RA contracts are not.[56]

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[52] CEDMC-2, p. 10, line 21 to line 25.

[53] CEDMC-2, p. 7, line 17 to line 23.

[54] CEDMC-2, p. 7, line 23 to line 24.

[55] CEDMC-2, p. 7, line 25 to p. 8, line 2.

[56] CEDMC-2, p. 8, line 3 to line 7.

Q 30 Do you agree with CEDMC's proposal?

A 30 No. PG&E does not agree with CEDMC's proposal.

First, California is not encouraging more RDRRs at the system level. For example, in D.19-07-009, the Commission has limited the role of RDRR in DRAM beginning with the 2019 solicitation.[57] For the 2023-2027 cycle, PG&E is not proposing new RDRR resources. The only RDRR PG&E bids into the CAISO market today is BIP, which is also open to third-party aggregators. While there is a cap to the reliability MW, the headroom under the cap allocated to PG&E is shared with DR aggregators who participate in BIP. Thus, PG&E customers who participate through third-party aggregators are not disadvantaged compared to customers who are directly enrolled with PG&E.

Second, it is not correct that the IOUs have a unique ability to freely transition a supply-side resource to load modifying. Any such transition would require CPUC approval and need to be integrated into the CEC's load forecast. And for the 2023-2027 cycle, PG&E is not expanding its load modifying DR beyond the existing critical peak pricing programs.

Lastly, third-party RA contracts are bilateral contracts; whether a bilateral contract is eligible for technology incentives should be negotiated between the IOU and the third-party DR provider. It is procedurally improper to introduce bilateral RA contracts as evidence here, as they are outside the scope of this proceeding.

2. Data Sharing (Witness: John Lin)

Q 31 What is OhmConnect's proposal related to data sharing?

A 31 OhmConnect proposes that the Commission require IOUs to provide customer data to third parties within 48 hours.[58]

Q 32 What is the basis for OhmConnect's proposal?

A 32 OhmConnect claims that the current "click-through" process under Electric Rule 24 is extremely cumbersome for the customer, riddled with delays from the IOUs, and contradicts the Commission's principles for DR.[59]

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57 D.19-07-009, p. 46.

58 OhmConnect-2, p. 26, line 24 to line 25.

59 OhmConnect-2, p. 26, line 3 to line 8.

OhmConnect believes that a data sharing standard of 48 hours is needed to prevent IOU data delays that undermine trust between customers and OhmConnect and make it difficult to motivate customers to participate in DR programs.[60]

Q 33 Do you agree with OhmConnect's proposal?

A 33 No, OhmConnect's proposal to establish data sharing standards is outside the scope of this proceeding and would be more appropriately addressed through the Click Through Application (A.18-11-015 et al.). In the Click -Through proceeding, PG&E fully briefed arguments opposing OhmConnect's similar request regarding the timeliness of data delivery and other metrics.[61] PG&E is currently awaiting a Proposed Decision in that case.

Q 34 Does OhmConnect offer alternative proposals to the existing "click-through" customer authentication and authorization process to provide customer data to third parties?

A 34 Yes, OhmConnect provides two alternative proposals. First, OhmConnect recommends that the Commission initiate a process to verify third party DR providers.[62] According to OhmConnect, a customer would then only need to verify their identity to authorize the third party to access their smart meter data.[63] Second, OhmConnect proposes that customers could authenticate their identify and utility account through another service, such as through Google, Facebook, or Apple credentials, rather than their IOU account number, username, and password.[64] OhmConnect claims that either of these methods would be simpler for customers while protecting their utility data.[65]

Q 35 Do you agree with OhmConnect's proposals to provide an alternative to the existing "click-through process?"

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[60] OhmConnect-2, p. 26, line 23 to line 25.

[61] See "Opening Brief of Pacific Gas and Electric Company (U 39 E) in 2018 Click-Through Authorization Process Proceeding," A.18-11-015 et al., May 28, 2021.

[62] OhmConnect-2, p. 26, line 8 to line 9.

[63] OhmConnect-2, p. 26, line 11 to line 12.

[64] OhmConnect-2, p. 26, line 13 to line 15.

[65] OhmConnect-2, p. 26, line 15 to line 16.

A 35 No, PG&E disagrees with both of OhmConnect's proposals. OhmConnect states that "the current 'click-through' process…is extremely cumbersome for the customer, riddled with delays from the IOUs, and contradicts the Commission's third Demand Response principle."[66] According to OhmConnect its proposals are "alternatives to the current process that would facilitate rather than discourage the authorization of sharing of the customer's smart meter data."[67] Alternatives to the click-through process[68] are not included in the scope of this proceeding, and remain scoped into the Click-Through Proceeding under the Alternate Solution proposals. Accordingly, the Commission should deny OhmConnect's proposals.

In addition, OhmConnect's proposals lack the detail and specificity required to fully understand what is being proposed. For example, OhmConnect states that using a third-party provider to authenticate a customer's identity and their utility account would be "far simpler for the consumer, while still protecting their utility data,"[69] but does not explain how any of these platforms would facilitate IOUs properly authenticating a customer and subsequently seeking authorization to release customer data on the customer's behalf. OhmConnect also does not provide support for its statement that its proposals would protect customer privacy. Even if the

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[66] OhmConnect-2, p. 26, line 3 to line 6.

[67] OhmConnect-2, p. 26, line 8 to line 9.

[68] PG&E's existing click-through process was approved by the Commission in Res.E-4868. The process of enrolling in DR service with a Rule 24 DRP begins and ends on a DRP's website. The enrollment process begins on a DRP's website where the customer is then routed to PG&E's website for identity authentication in accordance with PG&E's privacy controls. After the customer authenticates by entering log-in credentials directly on PG&E's webpage, the customer can authorize data sharing with the DRP. Once the authorization to release data is complete, the customer is automatically redirected back to the DRP's website. PG&E further notes that in accordance with the Commission's directive in Ordering Paragraph 29 of Res.E-4868, PG&E filed a cost estimate in its Click Through Application (A.18-11-015) to develop and implement an "Alternative Solution" click-through process to enable third party vendors to authenticate and authorize customers on DRP portal sites. PG&E's Click-Through Application is pending Commission decision.

[69] OhmConnect-2, p. 26, line 15 to line 16.

issues were in scope, there is insufficient detail to understand and assess the reasonableness of OhmConnect's proposals.[70]

Lastly, the Commission already concluded in D.16-06-008 that the "click-through" process is the appropriate method for verifying customer identity and authorization to release data. In doing so, the Commission concluded:[71]

> [W]e find that the click-through electronic process meets the requirements of Electric Rule 25, 27, and 33 because 1) the customer's consent is specific, in that it is for the specific purpose of receiving a demand response service, and 2) the consent is express, in that it provides reasonable verification that the customer completed the form.[72]

The proposals from OhmConnect are not consistent with the processes adopted in D.16-06-008 and OhmConnect does not explain how the Commission erred in its conclusions in that decision. As a result, PG&E recommends that the Commission deny OhmConnect's proposals.

3. Resolving Enrollment Conflicts (Witness: Brad Wetstone)

Q 36 What is OhmConnect's proposal related to resolving enrollment conflicts?

A 36 OhmConnect requests that the Commission adopt a three-pronged approach to resolving enrollment conflicts.[73] This includes identifying participation conflicts at the time of a customer's enrollment and providing a pathway to resolve them, allowing customers to resolve enrollment conflicts online and through a "one-click" process, and resolving enrollment conflicts no more than two weeks following receipt of the customer's request.[74]

Q 37 Do you recommend that the Commission adopt OhmConnect's proposal?

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70 An intervening party advancing their own proposals has a burden to produce supporting evidence. D.18-10-019, pp. 31-32.

71 D.16-06-008, p. 12. See also, Res.E-4868, p. 11 ("Decision 16-06-008 resolved the issue of authentication or verification in that it determined that the click-through authorization process sufficiently verifies the customer's identity").

72 Electric Rule 25 for Southern California Edison Company, Rule 27 for PG&E and Rule 33 for SDG&E embodies the Commission Privacy Rules established in "Rules Regarding Privacy and Security Protections for Energy Usage Data," D.11-07-056 and D.12-08-045. Res.E-4868, p. 9, fn. 14.

73 OhmConnect-2, p. 20, line 16 to line 17.

74 OhmConnect-2, p. 23, line 10 to line 18.

A 37 No, PG&E recommends that the Commission deny OhmConnect's proposal and defer further discussion of opportunities to resolve enrollment conflicts to the dual participation workshops proposed by PG&E. PG&E appreciates the spirit of OhmConnect's proposal and is open to further discussing opportunities to improve the customer experience. However, PG&E believes it would be more appropriate to develop potential solutions once there is more certainty around how dual participation rules may be modified.

In addition, PG&E finds that further discussion of OhmConnect's proposal may be warranted because the recommended solutions may not be appropriate for all DR programs. PG&E previously raised these concerns in response to OhmConnect's proposals regarding disenrollment processes in the Click-Through Application (A.18-11-015 et al.).[75] For instance, there are tariff provisions applicable to aggregators for BIP and CBP that specify minimum enrollment periods and disenrollment procedures. For BIP, customers can currently disenroll once annually during November. CBP and BIP aggregators are also required to submit an Add/Delete form to initiate disenrollment for their customers, so it is unclear whether OhmConnect's proposal may result in violations of the current program agreements. Further, if a customer is participating in another third-party's DR program, PG&E would not be privy to the applicable terms and conditions between the third-party DRP and the customer or be able to effectuate a disenrollment request. These examples illustrate that OhmConnect's proposal requires further refinement to identify how and when it could be applied to DR programs.

Lastly, PG&E notes that its current budget forecast for 2024-2027 does not include funding for the particular IOU DR program de-enrollment solution proposed by OhmConnect, which would involve Information Technology system and process enhancements. Without a clear understanding of the scope of work that may be required (as well as Commission approval of these activities), PG&E is unable to develop a forecast for the expected costs and timeline to complete the work at this time.

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75 Pacific Gas and Electric Company Improvements to Click-Through Customer Data Access Application Rebuttal Testimony, A.18-11-015, January 22, 2021.

E. Conclusion

Q 38 What is PG&E's recommendation for Program Policy Enhancements?

A 38 For the reasons discussed above, PG&E recommends that the Commission adopt PG&E's proposals regarding the following issues:

- Funding and scope for Load Flexibility, Market Integration Efficacy, and Market Potential Studies;
- Establishing workshops to further discuss dual participation issues
- Advancing efforts to automatically enroll customers in DR programs who receive technology incentives;
- The temporary suspension of PR rules for BIP in 2024 and 2025
- Creating an overarching policy that permits the use of PRs in BIP, ELRP, and CBP when the Governor or President issues an Emergency Proclamation/Executive Order in response to a heat event; and
- Extending the emergency reliability cap

In addition to adopting these proposals made by PG&E, PG&E recommends that the Commission reject the following new program policy enhancement proposals:

- CEDMC's proposal regarding competitive parity; and
- OhmConnect's proposals regarding data sharing and resolving enrollment conflicts.

Lastly, PG&E modifies its proposal regarding program flexibility to clarify that it supports the continued use of a mid-cycle review filing if the Commission is able to approve the filing within four months of submission to allow for timely implementation of program modifications.

Q 39 Does this conclude your rebuttal testimony?

A 39 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REBUTTAL TESTIMONY OF ANUROOBA BALAKRISHNAN AND WENDY BRUMMER

2024-2027 DEMAND RESPONSE PROGRAMS PROPOSALS

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2024-2027 DEMAND RESPONSE PROGRAMS PROPOSALS

A. Introduction

Q 1 What is the purpose of this rebuttal testimony?

A 1 This testimony responds to the direct testimony of the Public Advocates Office of the California Public Utilities Commission (Cal Advocates),[1] California Efficiency + Demand Management Council (CEDMC),[2] California Large Energy Consumers Association (CLECA),[3] the Joint Demand Response (DR) Parties,[4] Google Nest,[5] and the Small Business Utility Advocates (SBUA).[6] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below.

Q 2 Which programs are included in PG&E's testimony on 2024-2027 Demand Response Programs (DRP) Proposals?

A 2 PG&E's testimony on 2024-2027 DRPs Proposals includes proposals for the following:

- Base Interruptible Program (BIP);
- Capacity Bidding Program (CBP);
- SmartAC^{TM} Program;
- Automated Response Technology (ART) Program;
- Load Modifying Resources; and
- Marketing, Education and Outreach (ME&O) for DR Portfolio.

B. Summary of Parties' Positions

Q 3 Are there any 2024-2027 DRPs Proposals that are not contested by parties?

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1 Cal Advocates-2.

2 CEDMC-2.

3 CLECA-2.

4 Joint DR Parties-2.

5 Google Nest-2.

6 SBUA-2.

A 3 Yes, parties did not contest the following 2024-2027 DRPs Proposals:

- SmartAC Program;
- Load Modifying Resources; and
- ME&O for DR Portfolio.

Q 4 Do parties support PG&E’s 2024-2027 DRPs Proposals in their direct testimony?

A 4 Yes, the following parties support 2024-2027 DRPs Proposals:

- CEDMC supports all of PG&E’s proposals to enhance BIP[7] and the following proposals related to CBP:
  - Increasing incentives;
  - Accelerating energy payments;
  - Revising the payment/penalty structure;
  - Streamlining CBP;
  - Weekend participation; and
  - Continuing electronic enrollment.
- CLECA supports the following proposals related to BIP and does not opine on others:[8]
  - Increasing incentives;
  - Adding a 15-minute option; and
  - Changing event limits.
- Enchanted Rock supports PG&E’s proposal to increase BIP incentives and does not opine on other BIP enhancements.[9]
- Joint DR Parties support PG&E’s proposal to increase the performance cap for CBP to 110 percent.[10]

Q 5 Do parties provide any recommendations regarding PG&E’s 2024-2027 DRPs Proposals?

A 5 Yes, the following parties provide recommendations on PG&E’s 2024-2027 DRPs Proposals:

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7 CEDMC-2, p. 18, line 2.

8 CLECA-2, p. 3, line 21, p. 4, line 2, line 7.

9 Enchanted Rock-2, p. 3, line 18 to p. 4, line 11.

10 Joint DR Parties, p. 12, lines 6-7.

- CalPA, CLECA, and the Joint DR Parties provide recommendations on BIP;[11]
- CalPA, CEDMC, and Joint DR Parties provide recommendations on CBP;[12] and
- CalPA, CEDMC, Google Nest, and SBUA provide recommendations on ART.[13]

Q 6 Do you dispute or have comments on any of the parties' recommendations regarding 2024-2027 DRPs Proposals?

A 6 Yes, we address parties' recommendations in Section C.

Q 7 Do parties propose additional policy changes not included in PG&E's testimony?

A 7 Yes, CalPA recommends that the California Public Utilities Commission (Commission) transition CBP to a statewide program with the goal of promoting uniformity through clear guidelines for customers and aggregators and improving cost-effectiveness by reducing program administrative costs through economies of scale.[14]

Q 8 Do you dispute CalPA's recommendation to transition CBP to a statewide program?

A 8 Yes, we address this recommendation in Section D.

C. PG&E's Response to Parties' Recommendations Concerning PG&E's 2024-2027 DRPs Proposals

1. BIP (Witness: Anurooba Balakrishnan)

Q 9 What are PG&E's proposals for BIP in its 2024-2027 DRPs Proposals?

A 9 PG&E proposes the following modifications to BIP:[15]

- Permanently ending the lottery system for enrollment;

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11 CalPA-2, Chapter 4, p. 4-2, lines 3-9; CalPA-2, Chapter 2, p. 2-4, line 15 to p. 2-5, line 8; CLECA-2, p. 18, line 16 to p. 19, line 9; Joint DR Parties-2, p. 22, line 9 to p. 23, line 14.

12 CalPA-2, Chapter 4, p. 4-3, lines 4-9; CEDMC-2, p. 26, line 4 to line 6; Joint DR Parties-2, p. 11, line 28 to p. 17, line 6.

13 CalPA-2, Chapter 2, p. 2-5, line 11 to p. 2-7, line 20; CEDMC-2, p. 28, line 17 to p. 29, line 2; Google Nest-2, p. 8, lines 3-10; SBUA-2, p. 2, line 11 to line 21.

14 CalPA-2, Chapter 1, p. 1-1, lines 4-8.

15 Exhibit (PG&E-2), Chapter 3, p. 3-8, line 4 to p. 3-11, line 30.

- Requiring customers to remain in the program for at least six months before unenrolling from the program or raising their firm service level;
- Increasing incentive rates by $2/ kilowatt (kW) for May-October;
- Limiting events to 10 events during a rolling 30-day window and a 3-day limit on consecutive event days; and
- Including a 15-minute BIP option.

Q 10 Which parties recommend modifications to PG&E's proposals for BIP?

A 10 CalPA, CLECA, and the Joint DR Parties recommend modifications to PG&E's BIP proposals.

Q 11 What modifications does CalPA recommend for BIP?

A 11 CalPA recommends that the Commission deny the primary BIP forecast in PG&E's Application in favor of PG&E's alternative BIP forecast, which would mean denying PG&E's request for a $2/kW incentive increase for summer rates and maintaining 2018-2022 incentive levels.[16] CalPA also opposes PG&E's recommendation to adopt a 3-day maximum limit on consecutive events.[17]

Q 12 What is CalPA's basis for recommending that the Commission deny PG&E's request to increase BIP incentives?

A 12 CalPA states that PG&E's primary BIP forecast has a Total Resource Cost (TRC score of 0.84 and that its alternative BIP proposal has a TRC score of 1.05, which provides increased value to ratepayers.[18]

Q 13 Do you agree with CalPA's recommendation to deny PG&E's request to increase BIP incentives?

A 13 No, CalPA's rationale for opposing PG&E's request to increase BIP incentives is entirely based on the program's TRC score being less than 1.0, which is flawed for three primary reasons.

First, PG&E included an updated cost-effectiveness analysis in supplemental testimony on March 3, 2023 using the 2022 Avoided Cost Calculator (ACC), which the Commission approved via Resolution (Res.) E-5228 in September 2022 (four months after PG&E submitted its

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16 CalPA-2, Chapter 4, p. 4-2, lines 3-9.

17 CalPA-2, Chapter 2, p. 2-4, line 15 to p. 2-5, line 8.

18 CalPA-2, Chapter 4, p. 4-2, lines 3-9.

Application). Using the most up-to-date information to assess the cost-effectiveness of its DR portfolio, PG&E found that its primary BIP proposal has a TRC of 2.69 excluding Automated Demand Response (ADR) and 2.65 including ADR.[19] These figures demonstrate that even when assessing the viability of a program solely using its TRC score as proposed by CalPA, the BIP program is highly cost effective and adds value for ratepayers.

Second, the Commission explained in Decision (D.) 17-12-003 that the evolution of program objectives for DR may make it more difficult to forecast a TRC of at least 1.0 but that it may still approve proposals that do not meet this threshold because they address a valuable need.[20] CLECA explains that the usage of BIP has evolved in recent years from an infrequent emergency program to an essential reliability program that was called seven times by PG&E in 2020.[21] In addition, CLECA states that even though the incentive increases are a step in the right direction, "they are likely inadequate to effectively grow participation levels aligned with the utilities' stated goals [and that] current and potential new BIP customers will have to weigh the impact on their business of modestly increased incentives compared to dramatically higher expected curtailments."[22] CLECA's claim that even PG&E's proposed incentive increases may not be sufficient to increase participation in the program underscores that denying PG&E's proposal increases the likelihood of reducing available capacity at a time where the value from the program is arguably more needed than ever before.

Third, CalPA's argument against increasing BIP incentive levels due to its cost-effectiveness score is not aligned with other positions taken in its testimony, such as restricting the use of diesel back up generation and opposing BIP event limits.[23] For instance, Enchanted Rock explains that

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[19] Exhibit (PG&E-7), Chapter 12, p. 12-9, Tables 12-3 and 12-4.

[20] D.17-12-003, p. 121.

[21] CLECA-2, p. 8, line 16 to p. 9, line 11.

[22] CLECA-2, p. 18, lines 4-9.

[23] CalPA-2, Chapter 2, p. 2-4, line 15 to p. 2-5, line 8; Chapter 3, p. 3-1, lines 14-16.

"the proposed BIP rates should help bolster investments in cleaner Distributed Energy Resources (DER) in lieu of status quo investments in diesel backup generation as the revenues from the BIP program offset the higher costs associated with technologies that meet more stringent air quality requirements."[24] In short, increasing BIP incentives could actually support CalPA's stated intention of limiting the increase of diesel backup generation, something that PG&E and CalPA both support. In addition, CalPA does not support increasing BIP incentives but believes that it is "shortsighted"[25] to adopt a 3-day maximum on consecutive events "given the heat events California has faced in recent years like the 10-day heatwave in September 2022."[26] This approach asks BIP participants to commit to disrupting their operations more frequently with no commensurate increase in compensation.

Ultimately, PG&E recommends that the Commission adopt its proposal to increase BIP incentives because it is cost-effective and critical to preserving the value proposition for participants, which translates to maintaining critical capacity that has shown to be needed during emergencies and increasing investments available for non-PR back up generation.

Q 14 What is CalPA's basis for recommending that the Commission deny PG&E's recommendation to adopt a three-day maximum limit on consecutive events?

A 14 CalPA states that the Commission should not constrain BIP dispatches as heat events are expected to become more intense and frequent.[27] In addition, CalPA points out that BIP was only dispatched one day in 2021 and three days in 2022, so a three-day limit would not have prevented customer fatigue and attrition.[28]

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[24] Enchanted Rock-2, p. 3, line 24 to p. 4, line 2.

[25] CalPA-2, Chapter 2, p. 2-4, line 17.

[26] CalPA-2, Chapter 2, p. 2-4, line 17 to p. 2-5, line 1.

[27] CalPA-2, Chapter 2, p. 2-5, lines 1-2.

[28] CalPA-2, Chapter 2, p. 2-5, lines 3-8.

Q 15 Do you agree with CalPA's recommendation to deny PG&E's proposal to adopt a three-day maximum limit on consecutive events?

A 15 No, CalPA's rationale that customer fatigue and attrition would not have been mitigated through a three-day event limit is flawed. CLECA correctly explains that the increase in the frequency of consecutive dispatches has made it extremely challenging for BIP customers to manage their operations.[29] If BIP customers know ahead of time that there will be a maximum of three consecutive event days, they can more effectively incorporate adjustments to their operations, such as shifting production or carrying more inventory.[30]

Q 16 What modifications does CLECA recommend for BIP?

A 16 CLECA recommends that the Commission adopt an additional "all other hours" $1/kW incentive that would be applied to PG&E's summer hours outside of 4 p.m. – 9 p.m.[31]

Q 17 What is the basis for CLECA's recommendations?

A 17 CLECA states that its proposal would still be cost effective using the 2022 ACC and that it would accurately reflect that BIP customers commit to curtailing load during all hours of the day, every day of the year.[32]

Q 18 Do you recommend that the Commission adopt CLECA's proposal?

A 18 Not at this time. Instead, PG&E recommends that the Commission first adopt its proposal to increase May-October incentives by $2/kW and then assess the impacts on participation and retention before determining if a new incentive strategy, such as the one proposed by CLECA, may be needed. PG&E believes that CLECA's proposal requires more analysis to determine whether incentivizing curtailment outside of the peak period may inadvertently reduce performance during the peak period when reliability needs may be greatest. Therefore, PG&E recommends that the Commission re-visit this proposal as part of PG&E's proposed Phase III to

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29 CLECA-2, p. 9, lines 16-18.

30 CLECA-2, p. 9, lines 18-20.

31 CLECA-2, p. 18, line 16 to p. 19, line 9.

32 CLECA-2, p. 19, lines 2-9.

better understand whether this approach, and the increased budget needed to support it, are reasonable.

Q 19 What modifications do the Joint DR Parties recommend for BIP?

A 19 The Joint DR Parties recommend adding a new tier of incentives for customers over 5,000 kW.[33] This would include a $13/kW incentive for November-April and a $17/kW incentive for May-October.[34]

Q 20 What is the basis for the Joint DR Parties' recommendations?

A 20 The Joint DR Parties state that feedback from customers of this size has indicated that the increased cost to curtail due to economic conditions in recent years coupled with multiple dispatches per year have severely diminished the economic incentive to participate in BIP.[35]

Q 21 Do you recommend that the Commission adopt the Joint DR Parties' proposal?

A 21 Not at this time. The Joint DR Parties' proposal would result in a new incentive tier whose incentives would be $2.50/kW greater than PG&E's proposal for November-April ($13/kW compared to $10.50/kW) and $3.50/kW greater than PG&E's proposal for May-October ($17/kW compared to $13.50/kW). While customer feedback is a useful rationale, PG&E believes that additional analysis is necessary to justify the proposal, such as the size threshold for the new tier and the appropriate incentive rate. The program parameters would in turn require PG&E to adjust its forecasted BIP budget compared to what the Commission authorizes in Phase II of this proceeding.

For these reasons, PG&E recommends that the Commission first adopt its proposal to increase May-October incentives by $2/kW and further explore the Joint DR Parties' proposal as part of PG&E's proposed Phase III of this proceeding.

One way the Commission could address this issue and other similar questions related to incentive strategy (i.e., for smart thermostats) would be to host a workshop in early 2024. This would allow for the creation of a

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33 Joint DR Parties-2, p. 22, line 9 to p. 23, line 14.

34 Joint DR Parties-2, p. 23, lines 8-9.

35 Joint DR Parties-2, p. 22, line 18 to p. 23, line 2.

record on these matters related to BIP, CBP, and technology-specific issues (e.g. smart thermostats), to determine what changes may be needed to best support DR programs during the 2024-2027 DR program cycle. Having these discussions after the Phase II decision may be helpful because PG&E anticipates that the Commission's Phase II decision will address updates to the 2016 DR Cost Effectiveness Protocols, which may inform the types of incentive strategies that are viewed as cost effective.

2. CBP (Witness: Anurooba Balakrishnan)

Q 22 What are PG&E's proposals for CBP in its 2024-2027 DRPs Proposals?

A 22 PG&E proposes the following modifications to CBP:[36]

- Lowering the penalty threshold for CBP aggregators and increasing the performance cap, while enacting more severe penalties for non-performance;
- Removing the Prescribed option and all event duration options except the 1-hour event duration;
- Instituting testing enhancements such as an initial 4-hour test event for all resources with new customers;
- Converting the current weekend option to require Saturday participation and providing a capacity payment that is 25 percent of the capacity incentive rate for the applicable month and capacity nomination on Saturday;
- Requiring capacity nominations to be submitted no later than T-70 in advance of the operating month to ensure CBP resources are created and accounted for in Resource Adequacy (RA) supply plans (when required);
- Establishing a $650/megawatt-hour (MWh) bid cap and refining its CBP Elect option by offering two bid levels: a low bid level and a high bid level capped at $650/MWh;
- Permitting PG&E to recover any RA-related market penalties via the Demand Response Expense Balancing Account (DREBA) (when DR is required to be included in RA supply plans);
- Limiting the program window to 4 p.m. – 9 p.m.;

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36 Exhibit (PG&E-2), Chapter 3, p. 3-17, line 3 to p. 3-29, line 12.

- Replacing the current pass-through energy payment framework with calculated energy payments and penalties based on CAISO hourly energy prices; and
- Continuing to allow electronic enrollment.

Q 23 Are there any aspects of the proposals that require clarification?

A 23 Yes, as described further in Q/A 33, the Joint DR Parties raise concerns regarding the potential impacts of PG&E's proposal to modify the nomination window from T-15 to T-70. PG&E clarifies that the timing for its proposal would be contingent upon the Commission ordering PG&E to include DR on RA supply plans. In D.21-06-029, the Commission concluded:

> after the Commission confirms that the California Independent System Operator (CAISO) permits demand response (DR) resources to bid variably in its markets and implements a Federal Energy Regulatory Commission-approved exemption to the Resource Adequacy Availability Incentive Mechanism penalty for DR resources, each investor-owned utility will be directed to move its DR portfolios onto CAISO Supply Plans.

The Commission has not yet addressed these issues in the RA proceeding (Rulemaking 21-10-002). Unless the Commission addresses these issues in the upcoming Phase III RA decision (expected June 2023) or soon thereafter, the addition of DR to RA supply plans, and therefore the transition to a T-70 nomination window, may not occur until 2025 or later.

Q 24 Which parties recommend modifications to PG&E's proposals for CBP?

A 24 CalPA, CEDMC, the Joint DR Parties, and OhmConnect recommend modifications to PG&E's CBP proposals.

Q 25 What modifications does CalPA recommend for CBP?

A 25 CalPA recommends that the Commission deny the primary CBP forecast in PG&E's Application in favor of PG&E's alternative CBP forecast, which would mean denying PG&E's request to increase monthly capacity incentives while extending the program window to 4pm-11pm and including a 1-5 event hour option;[37]

Q 26 What is CalPA's basis for recommending that the Commission deny PG&E's primary CBP forecast?

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37 CalPA-2, Chapter 4, p. 4-3, lines 4-9.

A 26 CalPA states that PG&E's primary CBP forecast has a TRC score of 0.81 and that its alternative CBP proposal has a TRC score of 0.88, which "is slightly closer to the 1.0 TRC threshold."[38]

Q 27 Do you agree with CalPA's recommendation to deny PG&E's primary CBP forecast?

A 27 No, CalPA's rationale for opposing PG&E's primary CBP forecast is entirely based on the alternative proposal's TRC score being closer to 1.0, which is flawed for similar reasons discussed earlier related to BIP.

For example, PG&E included an updated cost-effectiveness analysis in supplemental testimony on March 3, 2023 using inputs from the 2022 ACC, which the Commission approved via Res.E-5228 in September 2022 (four months after PG&E submitted its Application). With the most up-to-date information to assess the cost-effectiveness of its DR portfolio, PG&E found that its primary CBP proposal has a TRC of 2.66 excluding ADR and 2.31 including ADR.[39] These figures demonstrate that even when assessing the viability of a program solely using its TRC score as proposed by CalPA, the CBP program is highly cost effective and adds value for ratepayers.

In addition, CBP incentive levels have not been updated since 2018, with the exception of a temporary increase authorized in the Emergency Reliability OIR (D.21-03-056) for October 2021 and 2022 from $2.27/kW to $6.80/kW.[40] This change resulted in a 60 percent increase in nominated capacity in October 2021 compared to October 2020.[41] This trend continued in October 2022—nominated capacity remained 55 percent higher than in October 2020. These results are significant, particularly considering ongoing summer capacity needs. PG&E's proposal increases incentives for each month that customers can participate in CBP (including a further increase in October to $7.79), which builds upon the progress achieved through the temporary increases in 2021 and 2022, by increasing available capacity throughout the entire DR season. PG&E recommends that the

38 CalPA-2, Chapter 4, p. 4-2, line 10 to p. 4-3, line 9.

39 Exhibit (PG&E-7), Chapter 12, p. 12-9, Tables 12-3 and 12-4.

40 D.21-03-056, p. 36.

41 Exhibit (PG&E-2), p. 3-26, lines 2-7.

Commission approve its proposal based on the demonstrated benefits of higher CBP incentives and the fact that these increases require only an eight percent increase compared to holding them steady at 2018 levels.[42]

Q 28 What modifications does CEDMC recommend for CBP?

A 28 CEDMC opposes the following proposals related to CBP:[43]

- Changing the nomination window;
- Providing two Elect bid price options;
- Recovering RA-related penalties via the DREBA; and
- Testing enhancements.

Q 29 What is the basis for CEDMC's recommendations?

A 29 CEDMC does not provide any rationale supporting its recommendations.

Q 30 Do you agree with CEDMC's proposed modifications?

A 30 No, PG&E recommends that the Commission adopt its CBP proposals for the reasons described in its prepared testimony.[44]

Q 31 What modifications do the Joint DR Parties recommend for CBP?

A 31 The Joint DR Parties propose modifications to PG&E's proposed payment/penalty structure and enhanced testing process.[45]

Q 32 What do the Joint DR Parties recommend related to PG&E's proposed payment/penalty structure?

A 32 The Joint DR Parties provide the following revisions (in bold on lines 2 and 3) to PG&E's proposal:

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[42] See Exhibit (PG&E-2), Chapter 10, Attachment A for a comparison of the incentive forecasts for PG&E's 2024-2027 base case scenario (incentive increase) and alternate scenario (no incentive increase).

[43] CEDMC-2, p. 26, lines 4-6.

[44] Exhibit (PG&E-2), p. 3-17, line 4 to p. 3-29, line 12.

[45] Joint DR Parties-2, p. 11, line 28 to p. 17, line 6.

TABLE 2-1
JOINT DR PARTIES' RECOMMENDED REVISIONS TO PAYMENT/PENALTY STRUCTURE

Line No.	Hourly Delivered Capacity Ration	Payment	Penalty
1	≥ 0.50 and ≤ 1.10	Unadjusted Hourly Capacity Payment Hourly Delivered Capacity Ratio Capped at 1.10	0
2	≥ 0 and < 0.50	0	Unadjusted Hourly Capacity Penalty = Unadjusted Hourly Capacity Payment * (0.50 – Hourly Delivered Capacity Ratio)
3	< 0	0	Adjusted Hourly Capacity Penalty = Unadjusted Hourly Capacity Payment * (0.50)

Q 33 What is the basis for the Joint DR Parties' recommendations?

A 33 The Joint DR Parties state that instituting a penalty for below a 0.50 Hourly Delivered Capacity Ratio of the Unadjusted Hourly Capacity Payment is extreme and that its adjustments to the proposed penalty structure address their concern related to transitioning from a T-15 nomination window to a T-70 nomination window.[46]

Q 34 Do you agree with the Joint DR Parties' rationale?

A 34 Yes, PG&E believes that the proposed changes are reasonable if the Commission adopts PG&E's recommendation to transition to a T-70 nomination window.

Q 35 Do you have any revisions to the Joint DR Parties' proposed modifications?

A 35 Yes, PG&E proposes the following revisions to the payment/penalty structure recommended by the Joint DR Parties to reduce potential ambiguity:

- Adding a new line (line 1) to clearly state that the Hourly Delivered Capacity Ratio is capped at 1.1;

46 Joint DR Parties-2, p. 12, lines 20-23; p. 13, lines 4-7.

- Adding a multiplication sign in the formula for Hourly Delivered Capacity Ratio ≥0.5 and <1.1, which appears to have been inadvertently omitted by the Joint DR Parties; and
- Revising text in the penalty column to clarify that the information in each cell represents the adjusted hourly capacity penalty.

PG&E believes that these corrections are consistent with the rationale explained by the Joint DR Parties.

TABLE 2-2
PG&E'S CLARIFICATIONS TO THE JOINT DR PARTIES' PROPOSED PAYMENT/PENALTY STRUCTURE

Line No.	Hourly Delivered Capacity Ratio	Adjusted Hourly Capacity Payment	Adjusted Hourly Capacity Penalty
1	≥ 1.1	[Unadjusted Hourly Capacity Payment] * 1.1Capped at 1.1	0
2	≥0.5 and <1.1	[Unadjusted Hourly Capacity Payment] * [Hourly Delivered Capacity Ratio]	0
3	≥ 0 and <0.5	0	[Unadjusted Hourly Capacity Payment] * (0.5 – [Hourly Delivered Capacity Ratio])
4	<0	0	[Unadjusted Hourly Capacity Payment] * 0.5

Q 36 What do the Joint DR Parties recommend related to PG&E's enhanced testing process?

A 36 The Joint DR Parties recommend revising PG&E's enhanced testing process so that resources can be called for up to two, two-hour test events per program season if the following conditions are met:[47]

1) It is a weekday during program hours after the 20th of the month;
2) If there has not been any form of dispatch in that given month;
3) If there has not been a test throughout the preceding month;
4) If previous event or test performance was below 75 percent of the presently nominated value or if the resource nomination for the given month is greater than 25 percent from the previous month;
5) There is not a state of emergency in California related to the grid; and
6) here are not forecasted capacity shortfalls.

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47 Joint DR Parties-2, p. 16, line 22 to p. 17, line 6.

Q 37 What is the basis for the Joint DR Parties' recommendations?

A 37 The Joint DR Parties state that a four-hour test event for all resources with new customers is inappropriate for two reasons. First, the Joint DR Parties explain that the dispatch will take place at the sub-lap level, which would subject customers that are not new to the testing requirements.[48] Second, the Joint DR Parties state that PG&E's proposal is in in conflict with "PG&E's Electric Sample Form No. 79-1076, Agreement for Aggregators Participating in the Capacity Bidding Program, Representation of Customers," which bestows the responsibility for training on the Aggregator.[49]

Ultimately, the Joint DR Parties conclude that PG&E's proposal is not customer-centric and proposes highly unnecessary and excessive testing without additional compensation that risk disincentivizing participation.[50]

Q 38 Do you agree with the Joint DR Parties' recommended revisions to PG&E's proposed enhanced testing process?

A 38 In part, yes. PG&E agrees with the Joint DR Parties' rationale for opposing PG&E's proposal to require a four-hour test event for all resources with new customers and retracts this proposal.

However, PG&E does not agree with the Joint DR Parties' proposal to limit the number of test events to two, two-hour tests per program season and believes that it is important to retain up to one, two-hour test event per month during the program season. PG&E believes that test events are necessary to validate the accuracy of nominations throughout the months of the season and that predefining the total number of test events in a season reduces the value of testing.

In addition, PG&E observes that conditions 1-3 and 6 proposed by the Joint DR parties are currently factors used to identify test events. PG&E agrees with condition 5, which is a logical new condition proposed by the Joint DR Parties to prevent calling test events during an emergency. However, PG&E opposes the portion of condition 4 proposed by the Joint DR Parties which states "or if the resource nomination for the given month is

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48 Joint DR Parties-2, p. 14, lines 8-15.

49 Joint DR Parties-2, p. 14, line 16 to p. 15, line 2.

50 Joint DR Parties-2, p. 15, lines 6-21.

greater than 25 percent from the previous month" because PG&E believes that it is inappropriate to evaluate nominated resources differently based on their nominated value. The value that is nominated alone provides no indication that the DR resource has not performed in previous test or market events, so it is unclear why a resource should be selected for testing only because the nominated value is higher than the previous month. PG&E identifies these changes to the Joint DR Parties' recommendations below (in strikethrough):

1) It is a weekday during program hours after the 20th of the month;
2) If there has not been any form of dispatch in that given month;
3) If there has not been a test throughout the preceding month;
4) If previous event or test performance was below 75 percent of the presently nominated value or if the resource nomination for the given month is greater than 25 percent from the previous month;
5) There is not a state of emergency in California related to the grid; and
6) There are not forecasted capacity shortfalls.

Q 39 What modifications does OhmConnect recommend for CBP?

A 39 OhmConnect opposes PG&E's proposal to lower the penalty threshold for Aggregators participating in CBP.

Q 40 What does OhmConnect recommend related to PG&E's recommended penalty structure for CBP?

A 40 OhmConnect recommends that the Commission deny PG&E's proposal.

Q 41 What is the basis for OhmConnect's recommendations?

A 41 OhmConnect states that PG&E submitted comments in the California Energy Commission Docket 21-DR-01 related to the qualifying capacity methodology for DR which stated that a penalty structure where payment is prorated up to 50 percent delivery is too lenient for underperformance.[51] According to OhmConnect, it is inconsistent to argue that a prorated capacity payment for performance above 50 percent is reasonable for a CBP aggregator while being too lenient for aggregators providing RA outside of an investor-owned utility (IOU) DR program.[52] OhmConnect

[51] OhmConnect-2, p. 6, lines 14-16.

[52] OhmConnect-2, p. 6, lines 16-18.

concludes that this approach runs counter to the Commission's determination that third-party and IOU DR should compete on a level playing field because it makes CBP a more valuable option than providing RA independently.[53]

Q 42 Do you agree with OhmConnect's recommendation to deny PG&E's request related to CBP penalties?

A 42 No, PG&E does not agree with OhmConnect's recommendation, which conflates PG&E's retail settlement calculation proposal with the qualifying capacity methodology, which is outside the scope of this proceeding. PG&E proposes to lower the threshold at which a prorated capacity payment would apply from 75 percent to 50 percent. However, this retail settlement calculation is not used to determine the qualifying capacity of PG&E's CBP program and the capacity penalty is not applied to the qualifying capacity.

3. ART Program (Witness: Wendy Brummer)

Q 43 What are PG&E's proposals for ART in its 2024-2027 DRPs Proposals?

A 43 ART is a new residential market-integrated[54] DR program that uses a pay-for-performance structure to enable customers to leverage their smart home technologies for load management beginning in 2024.[55] PG&E envisions that at least one of the following technologies will be required to participate: smart thermostat, electric vehicle, battery, heat pump water heater, smart appliance.[56] In addition, PG&E will require all participating technologies support daily automatic load management functions for time-of-use rates or any other time varying price rate plan.[57] Additional program parameters will be determined through a solicitation for a third-party implementer(s), including customer incentives, payment options, payment terms, technology manufacturer fees, new technology intake process, and marketing strategies and tactics.[58]

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53 OhmConnect-2, p. 6, lines 20-23.

54 ART will be market integrated as a Proxy Demand Resource.

55 Exhibit (PG&E-2), Chapter 3, p. 3-36, line 12 to line 14; p. 3-37, lines 12-16.

56 Exhibit (PG&E-2), Chapter 3, p. 3-39, Table 3-16, line 6

57 Exhibit (PG&E-2), Chapter 3, p. 3-39, Table 3-16, line 7.

58 Exhibit (PG&E-2), Chapter 3, p. 3-39, Table 3-16, line 8.

Q 44 Which parties recommend modifications to PG&E's proposals for ART?

A 44 CalPA, CEDMC, Google Nest, and SBUA recommend modifications to PG&E's ART proposals.

Q 45 What modifications does CalPA recommend for ART?

A 45 CalPA recommends that the Commission reduce PG&E's 2024-2027 ART forecast by $7.3 million to account for overstated load impacts and lower administrative costs.[59]

Q 46 What is CalPA's basis for claiming that the Commission should lower PG&E's ART forecast because it overstates the expected load impacts?

A 46 CalPA observes that 66 MW of PG&E's total forecasted 104 MW load impacts for ART are from smart thermostats.[60] CalPA states that although PG&E did not provide a specific reference for this load forecast, the estimates are consistent with the results from the August 9, 2022 "Smart Thermostat Time-of-Use Automation Study," which examined customers' responses to DR events and differentiated between customers who automated their smart thermostats based on time-of-use (TOU) rates and those who did not.[61] CalPA claims that PG&E's load impact estimates match average responses based on unoptimized thermostats (0.59 kW/site) instead of the estimated impacts from thermostats optimized for TOU rates (0.37 kW/site).[62] CalPA claims that the 0.37 kW/site assumption is more appropriate to reflect the fact that customers will be using smart thermostats for automated TOU response and therefore recommends that the Commission adjust the load impacts forecasted by PG&E for smart thermostats to 44 MW from 66 MW.

In addition, CalPA argues that PG&E's proposed 20 percent administrative budget is too high and should be reduced to 10 percent because the Commission has previously determined that 10 percent is an appropriate target for administrative budgets.[63] CalPA also states that

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59 CalPA-2, Chapter 2, p. 2-5, line 11 to p. 2-7, line 20.

60 CalPA-2, Chapter 2, p. 2-6, lines 5-6.

61 CalPA-2, Chapter 2, p. 2-6, lines 6 to p. 2-7, line 4.

62 CalPA-2, Chapter 2, p. 2-7, lines 4-7.

63 CalPA-2, Chapter 2, p. 2-7, lines 12-14.

10 percent is a reasonable administrative budget because PG&E plans to contract with a third-party/parties to provide critical implementation services, which should reduce PG&E's program administration costs.[64]

Q 47 Do you agree with CalPA's claim that PG&E's ART load forecast is based on unoptimized smart thermostats instead of thermostats optimized for TOU?

A 47 Yes, PG&E acknowledges that CalPA is correct that PG&E should have used the assumptions associated with thermostats optimized for TOU.

Q 48 Do you agree with CalPA that this adjustment warrants a reduction in PG&E's proposed incentive budget for ART?

A 48 No, PG&E recommends that the Commission retain its proposed incentive forecast because the program encourages participants to provide daily load shift in addition to DR load impacts as part of a more holistic load management effort. PG&E believes that this innovative program design will test the potential for new program models that support load management by paying for load impacts regardless of whether they occur through a DR program, daily load shift, or real-time pricing.

Q 49 Do you agree with CalPA that PG&E's administrative costs are too high and should be reduced so that they are capped at 10 percent of the program's total budget?

A 49 No, PG&E clarifies that the 20 percent administrative budget cited by CalPA includes program implementation and system costs which would be provided by a DER management system platform vendor. The architecture of ART, as indicated below in Figure 2-1, provides an opportunity for both original equipment manufacturers (OEM) and DR providers to participate. PG&E will provide APIs from our internal system, DR Market Integration System, to this new platform, which in turn integrates with the OEMs and DR providers to support eligibility, enrollment/unenroll, and dispatch operations. The cost of this new system is estimated to require at least 50 percent of the administrative budget.

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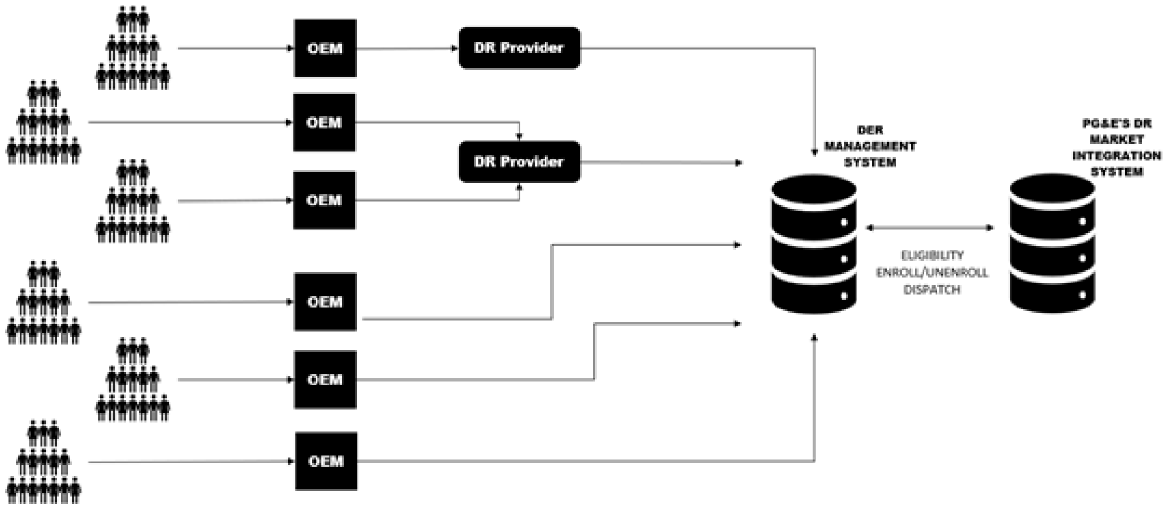
[64] CalPA-2, Chapter 2, p. 2-7, lines 14-20.

FIGURE 2-1
DIAGRAM OF ART PROGRAM ARCHITECTURE



A Request for Proposal (RFP) for the DER management system will provide more precise inputs.

Q 50 What modifications does CEDMC recommend for ART?

A 50 CEDMC recommends that PG&E consider new options to measure the performance of resources dispatched on a daily or near-daily basis to address the problems this creates with like-day baselines.[65] CEDMC recommends the use of universal control groups as an option.[66] In addition, CEDMC recommends that PG&E re-submit the program budget when it submits the final program design for Commission approval.[67]

Q 51 What is the basis for CEDMC's recommendations?

A 51 CEDMC states that it is unclear how the current CAISO baselines can be applied to ART because PG&E proposes ART as a daily program and CAISO baselines rely on looking back to recent "like" days when no DR events have occurred.[68] Also, CEDMC explains that it is reasonable to require PG&E to re-submit its ART budget when it submits its final program design to the Commission because there are key program design issues

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65 CEDMC-2, p. 28, line 17 to p. 29, line 2.

66 CEDMC-2, p. 28, lines 19-20.

67 CEDMC-2, p. 28, line 24 to p. 29, line 2.

68 CEDMC-2, p. 28, lines 17-22.

that will not be known until PG&E completes its solicitation for an implementer/implementers.[69]

Q 52 Do you agree with CEDMC's recommendations?

A 52 Yes, PG&E agrees with CEDMC that a control group methodology may be more appropriate for calculating program performance for the ART Program. PG&E will explore different settlement methodology options, likely with advice from a measurement and evaluation consultant. In addition, if the Commission approves the ART program, PG&E will submit an Advice Letter to create a new tariff with additional implementation details and the program design. As CEDMC points out,[70] the third-party performance incentive payments are far lower than the values most recently adopted by the Commission in the 2022 ACC update. These values were not yet available at the time that PG&E submitted its Application. To ensure third-party interest in ART, PG&E agrees that the incentive rates may need to be increased.

Q 53 What modifications does Google Nest recommend for ART?

A 53 Google Nest requests additional information on how customers participating in existing programs will transition to ART without experiencing decreased participation incentives and clarity on whether customers can pre-enroll and if customers will receive an upfront incentive;[71]

Q 54 Do you have comments in response to Google Nest's request for additional information?

A 54 Yes, PG&E will conduct an RFP to inform the program design. As envisioned currently, PG&E will pay performance incentives to third-party vendors who in turn provide incentives to customers. Currently, customers are enrolled in PG&E's Bring Your Own Thermostat pilot, as funded in the Summer Reliability OIR. Ideally, those customers would transition to ART. However, as CEDMC points out[72], the third-party performance incentive

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[69] CEDMC-2, p. 28, line 24 to p. 29, line 2.

[70] CEDMC-2, p.28, lines 6-15.

[71] Google Nest-2, p. 8, lines 3-10.

[72] CEDMC-2, p.28, lines 6-15.

payments are far lower than the new avoided capacity cost values and may need to be adjusted.

Q 55 What modifications does SBUA recommend for ART?

A 55 SBUA recommends that small business customers be eligible to participate in the program.[73]

Q 56 What is the basis for SBUA's recommendation?

A 56 SBUA claims that small commercial customers often use similar amounts of energy as residential customers, have similar types of equipment and technology, and face many of the same barriers to participating in DR programs, such as a lack of capital and a lack of sophistication regarding technological issues.[74]

Q 57 Do you agree with SBUA's recommendation?

A 57 PG&E does not support expanding ART to include small businesses starting in 2024. However, PG&E supports exploring this modification after two years of successfully managing the residential segment for ART.

D. PG&E's Response to CalPA's Proposal for a Statewide CBP (Witness: Anurooba Balakrishnan)

Q 58 What is CalPA's proposal for a statewide CBP?

A 58 CalPA recommends that the Commission deny all IOU proposals to continue administering CBP in their respective service areas and instead adopt a new statewide CBP.[75]

Q 59 What benefits does CalPA claim that a statewide CBP would deliver?

A 59 CalPA states that a statewide CBP "would promote uniformity through clear guidelines for customers and aggregators across the State and improve cost effectiveness by reducing program administrative costs through economies of scale."[76]

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73 SBUA-2, p. 2, lines 11-21.

74 SBUA-2, p. 2, lines 16-20.

75 CalPA-2, Chapter 1, p. 1-1, lines 4-6.

76 CalPA-2, Chapter 1, p. 1-1, lines 6-8.

Q 60 What is the TRC of the CBP proposed by PG&E?

A 60 PG&E's CBP has a TRC of 0.81 excluding ADR using the 2021 ACC and a TRC of 2.66 using the 2022 ACC.[77]

Q 61 Does CalPA recognize that PG&E's proposed 2024-2027 CBP is cost effective using the 2022 ACC?

A 61 No, CalPA discredits the higher TRC result by stating that it "is mainly attributable to an increase in the Avoided Cost of Generation Capacity value rather than improvements in program design."[78] In addition, CalPA recommends that the Commission disregard a cost effectiveness analysis using the 2022 ACC because PG&E did not provide the underlying spreadsheets that support its analysis (DR Cost-Effectiveness Report), as required by the December 19, 2022 *Assigned Commissioner's Amended Scoping Memo and Ruling* (Amended Scoping Memo).[79]

Q 62 Does the Commission provide greater weight to cost effectiveness analyses that achieve higher scores due to program designs rather than the Avoided Cost of Generation Capacity or any other input?

A 62 No, PG&E is not aware of any Commission precedent that provides greater weight to programs that achieve TRC scores based on the relative values of certain inputs. In fact, the Commission clarifies in the 2016 DR Cost Effectiveness Protocols that "for demand response, the most significant avoided cost is the avoided cost of generation capacity."[80]

Q 63 Did PG&E fail to provide the DR Cost Effectiveness Report that supports its analysis using the 2022 ACC as CalPA claims?

A 63 No, PG&E e-mailed the service list to this proceeding with a Notice of Availability that includes links to a public website to download the DR Cost Effectiveness Report.

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77 Exhibit (PG&E-7), Chapter 12, p. 12-9, Table 12-4.

78 CalPA-2, Chapter 1, p. 1-4, lines 1-3.

79 Amended Scoping Memo, p. 3.

80 2016 DR Cost Effectiveness Protocols, p. 28.

Q 64 What is the budget that CalPA proposes for a statewide CBP?

A 64 CalPA proposes a statewide CBP budget of $76.3 million for the 2024-2027 program cycle, which includes $66.7 million in incentives and $9.6 million in administrative costs.[81]

Q 65 How did CalPA derive its proposed budget for its statewide CBP proposal?

A 65 CalPA appears to have calculated a $66.7 million incentive budget by combining the CBP incentive budgets that each IOU proposed in their most up-to-date budget tables included in supplemental testimony.[82] CalPA states that the $9.6 million administrative budget is capped at 12.6 percent of total costs and claims that this approach is intended to "mirror the administrative costs for statewide programs in energy efficiency."[83] PG&E notes that the sum of the administrative budgets proposed by the IOUs for their respective CBP programs also totals $9.6 million.[84]

Q 66 Why does CalPA use the energy efficiency statewide administration framework as the basis for its statewide CBP proposal?

A 66 CalPA states that the Commission has long recognized the benefits of statewide administration of energy efficiency programs and points to the early development of statewide coordination on energy efficiency in the early 2000s as well as more recent decisions (D.16-08-019 and D.18-05-041) that transitioned certain energy efficiency programs to the current statewide model.[85]

Q 67 Does CalPA explain why the Commission transitioned certain energy efficiency programs to the current statewide model in D.16-08-019 and D.18-05-041 and which types of programs it identified as appropriate for statewide administration?

A 67 No, CalPA excerpts phrases from D.16-08-019 that refer to "easy program access to customers" and "lower transaction costs for administrators and

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81 CalPA-2, Chapter 1, p. 1-13, Table 1-6.

82 CalPA-2, Chapter 1, p. 1-13, lines 2-5. This includes $20.9 million for PG&E, $40.4 million for Southern California Edison Company (SCE), and $5.4 million for San Diego Gas & Electric Company (SDG&E).

83 CalPA-2, Chapter 1, p. 1-13, lines 5-7.

84 This includes $2.4 million for PG&E, $5.7 million for SCE, and $1.6 million for SDG&E.

85 CalPA-2, Chapter 1, p. 1-2, line 3 to p. 1-3, p. 1-3, line 5.

implementers"[86] but omits relevant information related to why the Commission transitioned to a statewide model for certain energy efficiency programs.

Q 68 What context does CalPA omit from its discussion of statewide energy efficiency programs?

A 68 First, CalPA does not mention that the Commission targeted specific types of energy efficiency programs as appropriate for statewide administration. This includes upstream and midstream programs (i.e., those targeted at manufacturers, distributors, and retailers of energy efficiency technologies) because these market actors' business operations do not vary significantly geographically within California.[87] In this case, a consistent, closely coordinated statewide approach could be beneficial, for example, to incentivize retailers to stock a particular technology and offer it at the lowest possible price to customers.

These same benefits do not translate to a DR program such as CBP. DR programs require real-time coordination with an IOU's grid operations teams, the CAISO, aggregators, and customers to balance electricity supply and demand. Because IOUs dispatch DR in response to local grid and customer needs, the same efficiencies and opportunities for scale that are possible through uniformity and standardization in energy efficiency are likely to become obstacles particularly when they are applied to operational and technological processes for DR dispatch, which vary from utility to utility.

Second, CalPA does not include that the lead program administrator for statewide energy efficiency programs is "the final arbiter or decisionmaker with respect to the program."[88] As described above, administering DR programs such as CBP requires an IOU to dispatch DR to meet local grid needs and have familiarity with the needs of specific customers. PG&E believes that it would be inappropriate for one IOU to be the final decisionmaker on dispatching DR within another IOUs service area.

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86 CalPA-2, Chapter 1, p. 1-3, lines 2-5.

87 D.16-08-019, pp. 50, 57-59.

88 D.16-08-019, p. 54.

Third, CalPA does not mention that statewide energy efficiency programs have not yet been evaluated. As a result, it is currently unknown whether statewide energy efficiency programs are delivering the benefits that the Commission envisioned in D.16-08-019.

Q 69 Does PG&E support CalPA's recommendation for a statewide CBP?

A 69 No, we strongly oppose the statewide CBP because the statewide energy efficiency framework is infeasible for CBP. In this rebuttal testimony, we have demonstrated that CalPA's attempts to invalidate the publication and results of our cost effectiveness analysis are inaccurate and not supported by Commission precedent. These results indicate that contrary to CalPA's claims, the existing CBP is highly cost effective. Moreover, we have provided additional context not included in CalPA's proposal which demonstrates that the Commission designed the energy efficiency statewide framework to meet the needs of specific energy efficiency programs and portfolio objectives that if applied to CBP, may inadvertently harm program performance to the detriment of grid reliability.

E. Conclusion

Q 70 What is PG&E's recommendation for 2024-2027 DRPs Proposals?

A 70 For the reasons discussed above, PG&E recommends that the Commission adopt PG&E's forecast and program proposals regarding the following issues:

- BIP;
- CBP;
- SmartAC Program;
- ART Program;
- Load Modifying Resources; and
- ME&O for DR Portfolio.

In addition, PG&E recommends that the Commission adopt the following proposals made by parties:

- The Joint DR Parties' modifications to PG&E's proposed payment/penalty structure for CBP, including the clarifications provided by PG&E;
- The Joint DR Parties' modifications to PG&E's proposed testing requirements for CBP, as further modified by PG&E; and

- CEDMC's recommendation for PG&E to re-submit its ART program design with additional details, including revised budgets and incentive proposals.

PG&E also recommends that the Commission deny the following proposals made by parties:

- CalPA's proposal to adopt the alternative forecasts for BIP and CBP;
- CalPA's recommendation that the Commission not limit BIP dispatches to three consecutive days as proposed by PG&E;
- The BIP incentive proposals made by CLECA and the Joint DR Parties, which should be further developed in Phase III of this proceeding;
- OhmConnect's recommendation that the Commission deny PG&E's requested CBP penalty structure;
- CalPA's recommendation that the Commission reduce PG&E's ART forecast by $7.3 million;
- SBUA's proposal to expand ART to include small business customers; and
- CalPA's recommendation to transition CBP to a statewide program.

Q 71 Does this conclude your rebuttal testimony?

A 71 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REBUTTAL TESTIMONY OF ALBERT K. CHIU, JOHN C. HERNANDEZ, AND RANDY CHIU

2024-2027 DEMAND RESPONSE TECHNOLOGY PROGRAMS AND PILOTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
REBUTTAL TESTIMONY OF ALBERT K. CHIU,
JOHN C. HERNANDEZ, AND RANDY CHIU
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2024-2027 DEMAND RESPONSE TECHNOLOGY PROGRAMS AND PILOTS

A. Introduction

Q 1 What is the purpose of this rebuttal testimony?

A 1 This testimony responds to the direct testimony of the Public Advocates Office of the California Public Utilities Commission (Cal Advocates),[1] California Efficiency + Demand Management Council (CEDMC),[2] California Large Energy Consumers Association (CLECA),[3] the Joint DR Parties,[4] Google Nest,[5] Polaris,[6] and Vehicle-Grid Integration Council (VGIC).[7] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below.

Q 2 Which programs are included in PG&E's testimony on 2024-2027 Demand Response Technology Programs and Pilots?

A 2 PG&E's testimony on 2024-2027 Demand Response Technology Programs and Pilots includes proposals for the following:

- Automated Demand Response (ADR);
- Demand Response Emerging Technology (DRET) Program;
- Smart Panel Pilot;
- Emergency Load Reduction Program (ELRP) Pilot; and
- Agricultural Demand Response Pilot (Ag Pilot)

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1 Cal Advocates-2.

2 CEDMC-2.

3 CLECA-2.

4 Joint DR Parties-2.

5 Google Nest-2.

6 Polaris-2.

7 VGIC-1.

B. Summary of Parties' Positions

Q 3 Are there any 2024-2027 Demand Response Technology Programs and Pilots that are not contested by parties?

A 3 Yes, parties did not contest the following 2024-2027 Demand Response Technology Programs and Pilots:

- DRET Program
- Smart Panel Pilot

Q 4 Do parties support PG&E's 2024-2027 Demand Response Technology Programs and Pilots in their direct testimony?

A 4 Yes, the following parties support certain proposals in PG&E's 2024-2027 Demand Response Technology Programs and Pilots:

- Google Nest supports ending ADR incentives for smart thermostats;[8]
- CEDMC, CLECA, and the Joint DR Parties support PG&E's proposal to allow Reliability Demand Response Resources (RDRR), such as the Base Interruptible Program (BIP), to be eligible for ADR incentives;[9]
- Polaris supports PG&E's proposal to permit customers enrolled in the Ag Pilot to be eligible for ADR incentives.[10]

Q 5 Do parties provide any recommendations regarding PG&E's 2024-2027 Demand Response Technology Programs and Pilots?

A 5 Yes, the following parties provide recommendations on PG&E's 2024-2027 Demand Response Technology Programs and Pilots;

- CEDMC provides recommendations on ADR;[11]
- CalAdvocates, CEDMC, CLECA, and VGIC provide recommendations on ELRP;[12] and
- Polaris provides recommendations on the Ag Pilot.[13]

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8 Google Nest-2, p. 9, line 15 to p. 10, line 8.

9 CEDMC-2, p. 19, line 14 to line 19; CLECA-2, p. 19, line 20 to p. 20, line 9; Joint DR Parties-2, p. 23, line 17 to p. 24, line 4.

10 Polaris-2, p. 4, line 1 to line 3.

11 CEDMC-2, p. 19, line 20 to p. 20, line 12.

12 CalAdvocates-2, Chapter 5, p. 5-2 line 26 to p. 5-4, line 7; CEDMC-2, p. 16, line 5 to line 10 and p. 16, line 24 to p. 17, line 6; CLECA-2, p. 29, line 14 to p. 30, line 19; VGIC-1, p. 20, line 14 to p. 22, line 6.

13 Polaris-2, p. 3 line 15 to p. 4, line 12.

Q 6 Do you dispute or have comments on any of the parties' recommendations regarding 2024-2027 Demand Response Technology Programs and Pilots?

A 6 Yes, we address parties' recommendations in Section C.

Q 7 Do parties provide additional recommendations related to PG&E's 2024-2027 Demand Response Technology Programs and Pilots that are not in response to specific proposals made by PG&E?

A 7 Yes, CalAdvocates, CEDMC, CLECA, and OhmConnect recommend additional modifications to ELRP.[14]

Q 8 Do you dispute any of the additional recommendations provided by parties related to ELRP?

A 8 Yes, we address parties' recommendations in Section D.

C. PG&E's Response to Parties' Recommendations Concerning PG&E's 2024-2027 Demand Response Technology Programs and Pilots

1. Automated Demand Response (Witness: Albert K. Chiu)

Q 9 What are PG&E's proposals for ADR in its 2024-2027 Demand Response Programs Proposals?

A 9 PG&E proposes the following related to ADR:[15]

- Continue to offer the option approved in D.21-12-015[16] that provides 100 percent of payment after the installation of technology is confirmed and DR program participation is verified;
- Expand the DR program participation requirement from three years to five years as an option if a customer chooses to receive 100 percent of the ADR incentive upfront;
- Expand the FastTrack application to increase the number of measures, business sectors, and customer segments;
- Permit RDRRs, such as BIP, to be eligible for ADR incentives; and
- Discontinue the residential deemed incentive application.

Q 10 Which parties recommend modifications to PG&E's proposals for ADR?

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14 CalAdvocates-2, Chapter 5, p. 5-2, line 26 to p. 5-4, line 7; CEDMC-2, p. 13, line 3 to p. 14, line 13, p. 15, line 13 to line 25; CLECA-2, p. 29, line 14 to p. 30, line 19; OhmConnect-2, p. 7, line 3 to p. 20, line 6.

15 Exhibit (PG&E-2), Chapter 4, p. 4-7, line 28 to p. 4-12, line 8.

16 D.21-12-015, Conclusion of Law 42.

A 10 CEDMC recommends modifications to PG&E's proposals for ADR.[17]

Q 11 What modifications does CEDMC recommend for ADR?

A 11 CEDMC recommends that PG&E retain the residential deemed incentive application and that if the Commission approves PG&E's request, it should be contingent on re-introducing them in the DR proceeding if they are removed from other programs.[18] In addition, CEDMC recommends that PG&E increase the ADR budget to assume that the Demand Response Auction Mechanism (DRAM) will continue.[19]

Q 12 What is CEDMC's basis for recommending that the Commission retain the residential deemed application?

A 12 CEDMC claims that ceding these incentives to non-DR programs risks future outcomes that may not benefit DR participants, such as the possibility that they may be eliminated if they are found to not be required for other programs' objectives.[20] In addition, CEDMC states that it would require parties to participate in a broader set of regulatory proceedings.[21]

Q 13 Do you agree with CEDMC's recommendation to retain the residential deemed incentive application?

A 13 No, PG&E disagrees with CEDMC's recommendation because ADR incentives are not intended to increase the adoption of connected technologies but rather to encourage the use of technologies with DR and OpenADR capabilities. PG&E finds that most residential connected technologies now have these capabilities, so it is no longer necessary to provide this incentive. PG&E's proposal notes that other programs whose objectives include increasing the adoption of connected devices are better positioned to continue incentivizing these technologies. Because the objective of ADR is different from other programs that incentivize residential connected technologies, PG&E recommends that the Commission deny

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17 CEDMC-2, p. 19, line 13 to p. 20, line 12.

18 CEDMC-2, p. 19, line 20 to line 21 and p. 20, line 4 to line 6.

19 CEDMC-2, p. 20, line 9 to line 10.

20 CEDMC-2, p. 19, line 21 to line 22, p. 20, line 2 to line 4.

21 CEDMC-2, p. 19, line 22 to p. 20, line 2.

CEDMC's proposal to re-introduce residential ADR incentives if they are eliminated elsewhere.

Q 14 What is CEDMC's basis for increasing the ADR budget to assume that DRAM will continue?

A 14 CEDMC states that it is premature to assume that the DRAM Pilot will end because the Commission has not yet reached this conclusion.

Q 15 Do you agree with CEDMC's recommendation to increase the ADR budget to assume that DRAM will continue?

A 15 No, PG&E believes that its proposed ADR budget of $9.5 million from 2024-2027 is sufficient to support DRAM if it continues.

2. Emergency Load Reduction Pilot Program (Witness: Randy Chiu)

Q 16 What are PG&E's proposals for ELRP in its 2024-2027 Demand Response Technology Programs and Pilots?

A 16 PG&E proposes the following related to ELRP:[22]

- Extend the pilot through 2027
- Remove all minimum dispatch requirements for the following ELRP Sub-Groups:
  - A.2 (Non-Residential Aggregators)
  - A.4 (Virtual Power Plant Aggregators)
  - A.5 (Electric Vehicle and Vehicle to Grid Integration)

Q 17 Which parties recommend modifications to PG&E's proposals for ELRP?

A 17 CEDMC and VGIC recommend modifications to PG&E's proposals ELRP.[23]

Q 18 What modifications do CEDMC and VGIC recommend?

A 18 CEDMC recommends that the Commission deny PG&E's recommendation to eliminate minimum dispatch requirements for Sub-Groups A.2, A.4, and A.5.[24] VGIC recommends that the Commission deny PG&E's recommendation to eliminate minimum dispatch requirements for

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22 Exhibit (PG&E-2), Chapter 4, p. 4-29, line 25 to line 27 and p. 4-30, line 16 to line 19.

23 CalAdvocates-2, Chapter 5, p. 5-2 line 26 to p. 5-4, line 7; CEDMC-2, p. 16, line 5 to line 10 and p. 16, line 24 to p. 17, line 6; CLECA-2, p. 29, line 14 to p. 30, line 19; VGIC-1, p. 12, line 10 to line 15.

24 CEDMC-2, p. 16, line 5 to line 8.

Sub-Group A.5.[25] VGIC does not comment on PG&E's proposal to eliminate minimum dispatch requirements for Sub-Groups A.2 and A.4.[26]

Q 19 What is the basis for the recommendations from CEDMC and VGIC to retain minimum dispatch requirements for A.2, A.4, and A.5?

A 19 CEDMC explains that minimum dispatch requirements for A.2, A.4, and A.5 should be retained because ELRP is an energy-only, best-efforts (i.e. no penalty) program.[27] According to CEDMC, although the program is voluntary, customers and DR providers must incur underlying costs to participate and the only way to recover these costs is through dispatch revenue.[28] CEDMC cautions that although the prolonged September 2022 heat wave triggered ELRP for all participants for multiple days, the same conditions may not materialize in future years and participants should retain certainty of revenues from participation.[29] VGIC explains that minimum dispatch requirements for A.5 should be retained because investor-owned utility (IOU) expenditures on A.5 incentives was minimal in 2022 and that maintaining the existing program design is needed to support the nascent development of the V2G market in California.[30]

Q 20 Do you agree with the recommendation from CEDMC and VGIC to retain minimum dispatch requirements for A.2, A.4, and A.5?

A 20 Yes, PG&E agrees to withdraw its request to eliminate minimum dispatch requirements for A.2, A.4, and A.5 for the reasons cited by CEDMC and VGIC. However, PG&E recommends that the Commission adopt its proposal for a Phase III of this proceeding so that it can assess whether minimum dispatch requirements remain necessary throughout the 2024-2027 DR program cycle.[31] A primary factor in the Commission's

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[25] VGIC-1, p. 20, line 15 to line 18.

[26] PG&E refers to the ELRP sub-groups by letter and number for the remainder of this chapter (i.e. A.2, A.4, A.5 rather than Sub-Groups A.2, A.4, and A.5).

[27] CEDMC-2, p. 14, line 15 to line 17.

[28] CEDMC-2, p. 15, line 8 to line 10.

[29] CEDMC-2, p. 15, line 10 to line 12.

[30] VGIC-1, p. 14, line 12 to line 14; p. 14 line 17 to p. 15, line 13.

[31] PG&E's Opening Comments on the *Assigned Commissioner's Ruling Directing Response to Questions and Energy Division Staff Proposals Related to Application 22-05-002 Phase II Issues* (Phase II ACR), April 21, 2023, pp. 1-5.

decision to require minimum dispatch hours for these subgroups is to support nascent technologies. For instance, the 30-hour minimum dispatch requirement for A.5 is intended to "help educate customers, aggregators, IOUs, and the Commission on the technology and systems needed to dispatch these resources."[32] As more experience is gained with the program, Phase III would provide an opportunity to continually assess whether this rationale and requirement remain necessary.

3. Agricultural Demand Response Pilot (Witness: Albert K. Chiu)

Q 21 What is PG&E's proposal for the Ag Pilot in its 2024-2027 Demand Response Technology Programs and Pilots?

A 21 PG&E proposes a new Ag Pilot that aims to increase DR participation and load reduction among agricultural customers who make up a substantial portion of peak load.[33] The Ag Pilot is based on a DRET Study and includes a two-product offering (performance only and capacity + penalty) due to feedback from customers, aggregators, and technology providers.[34] PG&E proposes a firm service level compensation approach, a day-ahead notification, and intends to test both economic and reliability event triggers to determine which triggers are optimal for agricultural customers.[35] PG&E recommends that customers be enrolled in an agricultural time-of-use (TOU) rate to participate in the pilot.[36]

Q 22 Which parties recommend modifications to the Ag Pilot?

A 22 Polaris recommends modifications to the Ag Pilot.[37]

Q 23 What modifications does Polaris recommend to the Ag Pilot?

A 23 Polaris provides the following recommendations:[38]

- Removing the proposed enrollment cap of 17.5 MW;
- Increasing capacity payments;

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32 D.21-12-015, p. 40.

33 Exhibit (PG&E-2), Chapter 4, p. 4-34, line 29 to line 31.

34 Exhibit (PG&E-2), Chapter 4, p. 4-37, line 1 to line 23.

35 Exhibit (PG&E-2), Chapter 4, p. 4-38, line 7 to line 18.

36 Exhibit (PG&E-2), Chapter 4, p. 4-38, line 19 to line 23.

37 Polaris-2, p. 3, line 15 to p. 4, line 12.

38 Polaris-2, p. 3, line 15 to p. 4, line 12.

- Including program parameters such as the notification window, event trigger, max/min events, in a Commission decision rather than an Advice Letter (AL) process;
- Offering automation incentives to respond to TOU and dynamic pricing, not just DR programs.

Q 24 Does PG&E propose to institute a 17.5 MW participation cap in the Ag Pilot?

A 24 No, PG&E clarifies that the 17.5 MW referenced by Polaris refers to the estimated MW load impacts for the Ag Pilot from the DRET Study conducted to inform the pilot design.[39]

Q 25 What is the basis for Polaris's recommendation to increase capacity incentives for the Ag Pilot?

A 25 Polaris states that the proposed capacity incentives are approximately 30% less than those available through CBP.[40] Polaris also claims that PG&E's proposal to change the CBP nomination window from T-15 to T-70 will make the program unviable for agricultural customers, and that incentives should be increased for the Ag Pilot to "provide a 'home' for both new Agricultural DR and participants for whom existing programs are no longer a fit."[41]

Q 26 Why are PG&E's proposed incentives for the Ag Pilot lower than those available through CBP?

A 26 In general, the incentive rates are different because the programs have different incentive structures and purposes. The CBP is an established DR program with a capacity payment and penalty incentive structure. The Ag Pilot is a new pilot that includes two different incentive options (a performance-only design and a capacity payment with small penalties) to test the comparative value of both offerings for the agricultural customer base.[42]

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39 For more information, see https://www.etcc-ca.com/reports/agricultural-demand-response-study

40 Polaris-2, p. 3, line 16 to line 19.

41 Polaris-2, p. 3, line 11 to line 12.

42 Exhibit (PG&E-2), p. 4-37, line 12 to line 23.

Q 27 Does PG&E agree with Polaris that it should modify the program design of the Ag Pilot to “provide a home for both new Agricultural DR and participants for whom existing programs are no longer a fit?”[43]

A 27 No, the purpose of the Ag Pilot is to test the optimal program configuration recommended in the DRET program’s Agricultural Demand Response Study.[44] This optimal design is based on a quantitative analysis that used a conjoint model survey of 160 PG&E agricultural customers to identify program design attributes that customers value most, coupled with a program design simulation tool that incorporated the expected costs and benefits of each program design.[45] As a result, PG&E believes that it would be inappropriate to use the Ag Pilot to fill a perceived gap in another program when this is not the intended purpose of the Pilot.

Q 28 What is the basis for Polaris’s recommendation for the Commission to include program parameters in a decision rather than through the AL process?

A 28 Polaris states that this clarity is needed as soon as possible to ensure there is sufficient time to recruit participants in the Ag Pilot and that including these parameters in a Commission decision provides parties with an opportunity to opine on the program design.[46]

Q 29 Do you agree with Polaris’s recommendation for the Commission to include program parameters in a decision?

A 29 Yes, PG&E agrees with Polaris but clarifies that this information is already included in PG&E’s direct testimony.[47] In addition, the DRET Study that informed the pilot design is publicly available and contains additional information regarding PG&E’s intended approach to administering the Ag Pilot.[48]

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43 Polaris-2, p. 3, line 11 to line 12.

44 Exhibit (PG&E-2), p. 4-36, line 19 to line 20.

45 Exhibit (PG&E-2), p. 4-35, line 9 to p. 4-36, line 7.

46 Polaris-2, p. 3, line 22 to line 26.

47 Exhibit (PG&E-2), Chapter 4, p. 4-37, line 1 to p. 4-39, line 7.

48 For more information, see https://www.etcc-ca.com/reports/agricultural-demand-response-study.

Q 30 What is the basis for Polaris's recommendation for PG&E to offer automation incentives to respond to TOU and dynamic pricing?

A 30 Polaris states that the need for load shift exists most days of the year and believes that incentives should reflect that policy, rather than focusing only on DR.[49]

Q 31 Do you agree with Polaris's recommendation to offer automation incentives to respond to TOU and dynamic pricing?

A 31 PG&E agrees that an ADR incentive should be available to customers enrolled in a dynamic rate such as Critical Peak Pricing or Real Time Pricing Tariffs, but not just to customers on TOU rates since one of the purposes of the ADR incentive is to require customers to leverage their automation technology in order to participate in a dispatchable DR program or dynamic rate. PG&E notes that it is currently piloting dynamic rates in the agricultural sector with Valley Clean Energy, pursuant to D.21-12-015,[50] in the Demand Flexibility Rulemaking (R.) 22-07-015).[51]

D. PG&E's Response to Parties' Additional Recommendations Concerning ELRP (Witness: Randy Chiu)

Q 32 Do parties recommend modifications to ELRP besides those related to PG&E's proposals?

A 32 Yes, CalAdvocates, CEDMC, CLECA, OhmConnect, and VGIC recommend additional modifications related to ELRP.[52]

Q 33 What additional modifications does CalAdvocates recommend related to ELRP?

A 33 CalAdvocates recommends that starting in 2024, the Commission should reduce the compensation rate for ELRP from $2/kilowatts per hour (kWh) to

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49 Polaris-2, p. 4, line 4 to line 8.

50 D.21-12-015, OP 53.

51 Assigned Commissioner's Phase 1 Scoping Memo and Ruling, R.22-07-005, November 2, 2022.

52 CalAdvocates-2, Chapter 5, p. 5-2, line 26 to p. 5-4, line 7; CEDMC-2, p. 13, line 3 to p. 14, line 13, p. 15, line 13 to line 25; CLECA-2, p. 29, line 14 to p. 30, line 19; OhmConnect-2, p. 7, line 3 to p. 20, line 6; VGIC-1, p. 20, line 19 to p. 22, line 6.

$1/kWh and decrease the residential dispatch window from 4-9pm to 6-8pm.[53]

Q 34 What is the basis for CalAdvocates' recommendation to decrease the compensation rate for ELRP from $2/kWh to $1/kWh, starting in 2024?

A 34 CalAdvocates states that $1/kWh is sufficient to encourage load reductions because DR resources did not submit a reference level change during the September 2022 heat event to allow bidding above $1000/megawatts per hour (MWh) despite conditions allowing bids to reach $2000/MWh.[54]

Q 35 Do you agree with CalAdvocates' recommendation to decrease the compensation rate for ELRP from $2/kWh to $1/kWh, starting in 2024?

A 35 No, PG&E does not agree with reducing the ELRP incentive rate to $1/kWh in 2024. While PG&E believes that it is reasonable to decrease ELRP incentive rates over time as the pilot matures, PG&E disagrees with CalAdvocates that DR pricing during the 2022 September heat event substantiates such a consequential, immediate change to the ELRP incentive rate. This rationale omits consideration of other key factors that support retaining the current incentive levels.

Q 36 What additional factors support retaining a $2/kWh incentive?

A 36 PG&E believes that the following factors support retaining a $2/kWh incentive in 2024:

1) ELRP is still a pilot and reducing incentive levels midway through the pilot term (2021-2025) would reduce the amount of data available to assess whether the incentive level is appropriate;
2) The current draft guidelines for the CEC's Demand Side Grid Support (DSGS) Program, which will be made available to IOU customers in 2023, includes an offering for IOU customers with back-up generation (BUG) that has an energy payment of $2/kWh and an additional standby payment of $0.25/kWh for each hour in which the committed load reduction is not actually dispatched because the balancing authority did not issue an Energy Emergency Alert at the level required for

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53 CalAdvocates-2, Chapter 5, p. 5-2, line 26 to p. 5-4, line 7.

54 CalAdvocates-2, Chapter 5, p. 5-3, line 3 to line 8.

dispatch.[55] This incentive structure offers greater potential compensation to participants than the $2/kWh available through ELRP.

If the Commission intends to prohibit the use of BUGs for ELRP participants (as contemplated in the Phase II ACR),[56] this policy change would require current ELRP participants with BUGs to transition to DSGS and establish DSGS as the only ELRP for BUG customers moving forward. If the Commission enacts this policy change starting in 2024, PG&E is concerned that a simultaneous ELRP incentive decrease may inadvertently reduce participation and performance among those who remain eligible for ELRP.

The Commission has concluded that incentivizing certain ELRP sub-groups is needed to support market development. For instance, the Commission acknowledged in D.21-12-015 that the inclusion of A.5 (EV/VGI Aggregation) is “an opportunity to deploy and scale this resource” and “help highlight the technology’s potential.”[57] Decreasing incentives by 50 percent midway through the pilot may undermine the Commission’s intention to help scale these technologies;

Q 37 Does PG&E have an alternative recommendation for reducing ELRP incentives?

A 37 Yes, PG&E recommends that the Commission defer the issue of incentive reductions to a Phase III of this proceeding as proposed by PG&E in its Opening Comments on the Phase II ACR.[58] This approach would allow for more data to be collected on the pilot’s performance using a $2/kWh incentive rate, including progress towards demonstrating the potential of sub-groups A.4 and A.5.

In addition, as discussed in Q/A 36 above, it is possible that ELRP participants with BUGs may transition to DSGS in 2024 if the Commission prohibits the use of BUGs in ELRP via the Phase II decision. If this occurs, PG&E believes that a Phase III would be the appropriate venue to assess

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55 See “Demand Side Grid Support Program Guidelines, Second Edition – Proposed Draft Program Guidelines, submitted April 4, 2023, CEC Docket 22-RENEW-01.

56 Phase II ACR, pp. 8-9.

57 D.21-12-015, p. 39.

58 PG&E Phase II ACR Opening Comments, April 21, 2023, pp. 1-5.

the impacts of the initial rollout of the DSGS program to IOU customers and ensure that any modifications to the ELRP compensation structure promote complementarity between the programs.

Q 38 What is the basis for CalAdvocates' recommendation to reduce the residential dispatch window from 4pm-9pm to 6pm-8pm, starting in 2024?

A 38 CalAdvocates states that reducing the residential dispatch window is sensible because the 6pm-8pm period is when system needs are most acute and conservation efforts by residential customers would be most effective if targeted.[59] CalAdvocates also claims that this change will make it easier for customers to adapt their behavior and reduce overall costs by eliminating high-cost incentive payments for reductions that are not as valuable to the grid.[60]

Q 39 Do you agree with CalAdvocates' recommendation to reduce the residential dispatch window from 4pm-9pm to 6pm-8pm, starting in 2024?

A 39 No, PG&E disagrees with CalAdvocates' recommendation and instead recommends that the Commission assess this proposal in a Phase III of this proceeding. PG&E believes that this change requires more coordination and development with other parties, in particular input from the California Independent System Operator (CAISO).

Specifically, it is unclear whether concentrating residential load reduction in the 6pm-8pm window may have the unintended impact of increasing residential usage from 4pm-6pm or 8pm-9pm and if so, whether this would be detrimental to CAISO's overall reliability planning. In addition, Flex Alerts are the event trigger for A.6 and typically call for load reduction between 4pm-9pm. Therefore, modifications to the program window for A.6 would need to be coordinated with Flex Alert and ELRP marketing, education, and outreach (ME&O) efforts to prevent customer confusion. Lastly, PG&E believes that CalAdvocates' claim that shortening the window would reduce overall costs may not necessarily be accurate. If customers do find a 6pm-8pm window to be more convenient, it is possible that more

[59] CalAdvocates-2, Chapter 5, p. 5-3, line 17 to p. 5-4, line 1.

[60] CalAdvocates-2, Chapter 5, p. 5-4, line 1 to line 4.

customers participating in a shorter window may actually result in the same or higher costs than if the window remained 4pm-9pm.

Q 40 What additional modifications does CEDMC recommend related to ELRP?

A 40 CEDMC provides the following recommendations related to ELRP:

1) Eliminating the requirement in D.21-12-015 for PG&E to automatically enroll customers in ELRP who are enrolled in California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance (FERA), as well as those who receive Home Energy Reports and instead focusing on increasing self-enrollments in the program.[61]
2) Calculating ELRP Group B Incremental Load Reduction (ILR) at the meter level, consistent with the methodology for Group A.[62]
3) Adopting a 10-hour minimum dispatch requirement for Group B.[63]

Q 41 What is the basis for CEDMC's recommendation to eliminate automatic enrollment in ELRP and focus on increasing self-enrollments?

A 41 CEDMC explains that the results from the ELRP Load Impact Assessments indicates high levels of free ridership and that ex post load impacts were largely attributable to Flex Alerts with little to no incremental load impacts associated with ELRP.[64]

Q 42 Do you agree with CEDMC's recommendation to stop automatically enrolling certain residential customers in ELRP A.6 and instead focus on increasing self-enrollments?

A 42 Yes, PG&E supports eliminating the requirement to automatically enroll CARE/FERA customers and those receiving Home Energy Reports because it would mitigate inadvertent free ridership while allowing the IOUs to focus on increasing self-enrollments and supporting customers who choose to participate in the program.

However, PG&E believes that potentially unenrolling customers who were automatically enrolled in the program requires development of a detailed tactical plan, which includes customer outreach and coordination

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61 CEDMC-2, p. 16, line 1 to line 3; D.21-12-015, Ordering Paragraphs (OP) 28, 34.

62 CEDMC-2, p. p. 17, line 3 to line 6.

63 CEDMC-2, p. 16, line 24 to p. 17, line 2.

64 CEDMC-2, p. 15, line 15 to line 17, line 21 to line 25.

with relevant stakeholders such as Community Choice Aggregators (CCA), to minimize any unintended customer and program impacts. As a result, PG&E recommends that the Commission direct the IOUs to submit an AL which proposes a process to facilitate unenrolling existing customers that were auto-enrolled in ELRP and no longer auto-enrolling customers moving forward. The AL would include an overview of the expected timing to deploy this process, a forecast of anticipated costs, and an outreach and notification process.

Q 43 What is the basis for CEDMC's recommendation to adjust the methodology for calculating ILR for Group B so that it is consistent with Group A?

A 43 CEDMC explains that currently Group A performance is calculated at the meter level while Group B performance is calculated at the CAISO resource level.[65] CEDMC claims that this results in a more favorable compensation structure for Group A customers because it allows negative performance intervals to be "zeroed out" from the ILR calculation while negative performance intervals are included in the ILR calculation for Group B customers.[66]

Q 44 Do you agree with CEDMC's recommendation to adjust the methodology for calculating ILR for Group B so that it is consistent with Group A?

A 44 No, PG&E disagrees with modifying the methodology used to calculate ILR for Group B customers. PG&E submitted Advice 4950-E-A on March 24, 2023 to modify the existing ILR methodology used for Group A customers to align it with the current methodology used to calculate ILR for Group B customers, consistent with the recommendation to do so from Energy Division Staff in the Phase II ACR.[67] This proposal establishes a consistent methodology for calculating ILR among both groups of ELRP customers.

Q 45 What is the basis for CEDMC's recommendation to introduce a 10-hour minimum dispatch requirement for Group B customers?

A 45 CEDMC states that it is unfair and inappropriate for certain Group A customers to benefit from a degree of certainty regarding the number of

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65 CEDMC-2, p. 13, line 11 to line 12.

66 CEDMC-2, p. 14, line 2 to line 13.

67 Phase II ACR, Appendix A, Staff Proposal B.

hours they will be dispatched, particularly since it believes that there is a strong desire among some state agencies and parties that third-party DR be dispatched more frequently.[68]

Q 46 Do you agree with CEDMC's recommendation to introduce a 10-hour minimum dispatch requirement for Group B customers?

A 46 No, PG&E disagrees with the recommendation because unlike Group A customers who might not be in another DR program, Group B customers are already participating in other CAISO integrated DR programs. In addition, D.21-12-015 does not provide PG&E with the same discretion to dispatch Group B as it does for Group A. Specifically, D.21-12-015 specifies that for Group B "the start time and duration specified in the DA Alert defines the Group B ELRP event window."[69] This is in contrast with what is directed for Group A where "the start time and duration specified by the IOU defines the ELRP event window."[70] As a result, PG&E believes that it is unnecessary for Group B customers to have minimum dispatch hours.

Q 47 What additional modifications does CLECA recommend related to ELRP?

A 47 CLECA recommends that the Commission modify the rules for BIP-ELRP dual participants to provide compensation for ILR during non-overlapping events.[71]

Q 48 What is the basis for CLECA's recommendation to allow compensation for BIP-ELRP dual participants during non-overlapping events?

A 48 CLECA states that its proposal would increase resources available during ELRP events and improve reliability without risking the potential loss of BIP participants who are unable to curtail beyond their existing obligations.[72]

Q 49 Do you agree with CLECA's recommendation to provide compensation to BIP-ELRP dual participants during non-overlapping events?

A 49 Yes, PG&E agrees with CLECA's recommendation. CLECA's recommendation would support increased participation in ELRP and not

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68 CEDMC-2, p. 14, line 14 to p. 15, line 5.

69 D.21-12-015, Attachment 2, p. 10.

70 D.21-12-015, Attachment 2, p. 10.

71 CLECA-2, p. 29, line 14 to line 15.

72 CLECA-2, p. 29, line 17 to line 19.

result in double counting or double compensation because it would require PG&E to provide ELRP compensation only when ELRP events do not overlap with BIP events.

Q 50 What additional modifications does OhmConnect recommend related to ELRP?

A 50 OhmConnect provides the following recommendations related to ELRP:[73]

1) Establishing ELRP as an “on-ramp” to economic DR
2) Launching a market awareness campaign, which includes:

- Maintaining and improving the current IOU DR web pages;
    - Implementing an email campaign twice per season (once in the spring and once in mid-summer) to notify customers about their demand response options
    - Requiring the IOUs to provide a short form in their ME&O that allows customers to provide their contact information to DR providers if they are interested in learning about third-party DR programs;

3) Standardizing Flex Alert as the day ahead trigger for all ELRP sub-groups (with optional exclusion of A.1 and A.2)

Q 51 How does OhmConnect envision using ELRP as an “on-ramp” to economic DR?

A 51 OhmConnect proposes that the Commission require the IOUs to include ME&O about all other available DR programs as part of ME&O for ELRP.[74]

Q 52 What is the basis for OhmConnect’s recommendation to use ELRP to provide ME&O regarding all available DR programs?

A 52 OhmConnect explains that 2022 ex post load impacts for ELRP participants were much lower for auto-enrolled customers compared to those who self-enrolled in the program.[75] OhmConnect contrasts this with economic DR programs which contributed much higher load impacts per customer and concludes that if ELRP continues, the Commission should use it to

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73 OhmConnect-2, p. 7, line 13 to line 16; p. 12, line 25 to 26; OhmConnect-2, p. 18, line 7 to line 9.

74 OhmConnect-2, p. 7, line 8 to line 16.

75 OhmConnect-2, p. 9, line 7 to 13.

encourage customers to enroll in “much more impactful and cost-effective economic demand response programs.”[76]

Q 53 Do you agree with OhmConnect’s recommendation to use ELRP as an “on-ramp” to providing customers with information about all available DR programs?

A 53 No, PG&E disagrees with using ELRP as an “on-ramp” to other DR programs because PG&E believes that this approach is counterproductive and may cause customer confusion. In support of its proposal, OhmConnect’s focuses on the underperformance of ELRP in 2022[77] and reminds the Commission of its previous warning “that a program that relies solely on behavioral interventions, with a customer pool that has been primarily auto-enrolled without notice, would yield limited actual impact at high ratepayer cost.”[78] However, OhmConnect’s proposal does not address ELRP underperformance; in fact, it appears likely to exacerbate performance issues by recommending that the Commission leverage specific ME&O campaigns intended to support the success of ELRP (e.g. via increased self-enrollments, greater event awareness, etc.) to instead drive customers to enroll in other DR programs. Ultimately, PG&E recommends that the Commission deny OhmConnect’s proposal because it appears likely to undermine the problem it purports to solve.

Q 54 OhmConnect’s proposal for the IOUs to implement a DR market awareness campaign states that the IOUs should maintain and improve their DR web pages because they do not comply with D.17-12-003 by including information only about CBP aggregators and DRAM providers.[79] Do you agree with OhmConnect’s claim that the IOU websites are non-compliant with D.17-12-003?

A 54 No, OP 46 of D.17-12-003 was clear about the information that was to be posted on the webpages of the IOUs. Specifically, “the names, logos, web addresses, and 2-sentence program descriptions” associated with a

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[76] OhmConnect-2, p. 10, line 3 to line 16.

[77] OhmConnect-2, p. 9, line 10 to p. 10, line 16.

[78] OhmConnect-2, p. 8, line 3 to line 5.

[79] OhmConnect-2, p. 16, line 10 to line 13.

"qualified third-party demand response provider operating in their service territory are provided on the main home page of each utility's demand response home page." OP 46 further defined that a "qualified third-party demand response provider shall have executed a demand response contract with the utility; the contract can *either* be for providing *demand response aggregator services* or to provide *demand response through the demand response auction mechanism*."[80]

Based on this very specific OP, PG&E continuously adds and removes from its website information on DRAM DR Providers with whom it currently has a relationship (i.e., an executed contract for the DRAM year). In addition, as required by OP 46, the IOUs collaborated with the Energy Division to develop disclaimer language and each IOU developed a plan on how it would inform customers about the existence of the main demand response web page. In response, PG&E took a number of actions to promote DR including those offered by third party entities. These actions were presented to the CPUC via PG&E's AL 5322-E, which was approved. PG&E's actions were consistent with D.17-12-003, and OhmConnect's assertion that actions taken by PG&E is not compliant or "not reasonable" is inconsistent with the facts at hand.

Q 55 OhmConnect's proposal for a DR market awareness campaign also recommends that the IOUs conduct an email campaign twice per season (spring and mid-summer) to notify customers about their DR options. Do you agree with this proposal?

A 55 No, PG&E does not. As part of the 2018-2022 DR funding cycle (A.17-01-012), OhmConnect made a similar request to have IOUs "advertise to customers…online marketplaces where customers can view information about all available DR programs, both IOU and third-party," and even offered suggestions of information to be displayed.[81] D.17-12-003 made it clear in OP 46 that the IOUs obligation is limited to parties is has a relationship with (i.e., CBP Aggregators and current DRAM sellers).

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[80] Emphasis added.

[81] Direct Testimony of OhmConnect in A.17-01-012, p. 3-3 to 3-5.

The IOUs should not have an obligation to promote entities that have no relationship with the IOUs. It would be unfair to ask ratepayers to fund acquisition and marketing activities on behalf of individual for-profit entities, who are solely responsible for development of their business. Lastly, PG&E points out that third-party DRPs are also able to support CCA DR and load management programs,[82] but these CCAs are not being asked to promote these entities. It would seem inconsistent to require IOU LSEs to promote DRPs, but not CCA LSEs, especially in the context that CCAs and ESPs already serve approximately 60 percent of all load within PG&E's service area.[83] Moreover, it appears up to half of the 12 CCAs in PG&E's service area have some type of DR program.[84] To this end, if the CPUC were to require additional promotion of 3rd party DRPs then such requirement should apply equally to CCAs/ESPs in the context of leveling the playing field.

Q 56 OhmConnect's proposal for a DR market awareness campaign recommends that the IOUs provide a short form to customers that allows them to provide their contact information to DR providers if they are interested in learning more about the DR provider's own DR programs. Do you agree with this proposal?

A 56 No, as described above, PG&E does not agree with this proposal because it believes that it is not appropriate to use ratepayer funding to collect and transmit a customer's contact information to a DR provider for marketing and soliciting the customer to subscribe to a DR provider's products and services.

Q 57 What is the basis for OhmConnect's recommendation to standardize Flex Alert as the day ahead trigger for all ELRP groups (with optional exclusion of A.1 and A.2)?

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82 The Council + Leap Phase 1 Supplemental Testimony in A.22-05-002, dated August 5, 2022 at p. 2, lines 3-4. Joint Community Choice Aggregators (CCA) direct testimony filed April 21, 2023 at p. 3. JCCA is listed as comprised of at least five CCAs (EBCE, MCE, PCE, SCP and the City of San Jose). Details of offerings are found in Attachments A-D of the filing.

83 PG&E metric as of end of year 2022. This figure is expected to continue to increase as several communities are planning to join CCA service in 2024 and beyond.

84 Link: CCA Programs – CalCCA (cal-cca.org) (Open the "Demand Response" drop-down menu for a listing of CCAs operating in PG&E's service territory with DR programs.)

A 57 OhmConnect states that the current approach to sub-group dispatch is "arbitrary, confusing, and preferences IOU-administered sub-groups."[85] In addition, OhmConnect explains that A.1 and A.2 may be exceptions to its proposal to standardize Flex Alert as the day ahead trigger for all ELRP groups because these participants are large customers and a day-of trigger may be more appropriate for them due to the high costs associated with disrupting their operations.[86]

Q 58 Do you agree with OhmConnect's recommendation to standardize Flex Alerts as the day ahead trigger for all ELRP groups (with optional exclusion of A.1 and A.2)?

A 58 No, PG&E disagrees with OhmConnect's recommendation because its argument that the existing ELRP event triggers "creates inequity and confusion" is based on a single example that the IOUs dispatched customers in A.2, A.4, and A.5 following a Flex Alert on August 17, 2023.[87] OhmConnect does not mention that PG&E dispatched these ELRP sub-groups in response to a Flex Alert because it must comply with the Commission's requirements related to minimum dispatch hours (10 hours for A.2, 20 hours for A.4 and 30 hours for A.5).[88] Since OhmConnect does not demonstrate why the Commission erred in establishing CAISO's "Alert, Warning, Emergency" process for ELRP triggers, PG&E recommends that the Commission deny OhmConnect's recommendation to standardize all ELRP triggers as a Flex Alert.

Q 59 What additional modifications does VGIC recommend related to ELRP?

A 59 VGIC provides the following recommendations related to ELRP:[89] Improve flexibility to allow for faster enrollments;

1) Prohibiting the IOUs from proposing fundamental program design changes that limit participation outside of a formal proceeding;

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85 OhmConnect-2, p. 18, line 6 to line 7.

86 OhmConnect-2, p. 19, line 18 to line 21.

87 OhmConnect-2, p. 18, line 27 to line 29.

88 D.21-12-015, pp. 31-41.

89 VGIC-1, p. 20, line 14 to p. 22, line 6, p. 30, line 14 to line 16.

2) Requiring future changes to A.5 be limited to those that are intended to expand participation rather than constrain it;

3) Moving up the due date for the IOUs to submit ALs to propose ELRP modifications from January 15 to November or December of the previous year; and

4) Allowing telematics to be used in ELRP on an interim basis until a new plug-in electric vehicle (PEV) telematics submetering protocol is adopted.

Q 60 What is VGIC's basis for recommending that PG&E improve its flexibility to allow for faster enrollments?

A 60 VGIC states that they have been informed in some cases that aggregators were requested to complete a technical integration with the utility/program administrator's resource management system prior to completing enrollments.[90]

Q 61 Do you agree with VGIC's recommendation that PG&E be more flexible with its requirements to allow for faster enrollments?

A 61 No, PG&E does not require technical integrations in order to complete enrollments and is unaware of any such cases occurring as described by VGIC.

Q 62 What is VGIC's basis for recommending that the Commission prohibit the IOUs from proposing fundamental program design changes that limit ELRP participation outside of a formal proceeding, and limit future changes to A.5 only to those that are intended to expand participation?

A 62 VGIC states that there should be certain issues that are "off-limits" for ELRP program design changes made through an AL because including changes in annual filings that potentially limit participation causes significant uncertainty and disruption for participants, who require reasonable expectations of market certainty across multiple seasons.[91]

Q 63 Do you agree with VGIC's recommendation to require that future changes to A.5 only include those that are intended to expand participation?

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90 VGIC-1, p. 21, line 2 to line 4.

91 VGIC-1, p. 21, line 12 to line 18.

A 63 No, PG&E does not agree that it is appropriate to constrain PG&E's ability to propose certain modifications that may limit participation by a certain sub-group of customers because (1) this stipulation is vague as to what constitutes "limiting participation" and (2) fails to recognize that there are many reasons why PG&E may need to implement a program change that could be interpreted by a stakeholder as limiting participation (e.g. targeting an offering to meet localized grid issues, aligning incentives with market factors, etc.).

Q 64 Do you agree with VGIC's recommendation to prohibit PG&E from proposing fundamental program design changes outside of a formal proceeding?

A 64 Yes, PG&E believes that VGIC's observations regarding the existing ELRP AL process are valid and believes that it appears to create unintended consequences for all parties involved due to timing constraints created by the AL process. Following the DR season, the IOUs require time to analyze program performance and develop potential recommendations to the program. Once these recommendations are included in an AL, stakeholders require time to review and respond to the filings. The Energy Division needs similar time to conduct their own due diligence and ultimately issue a disposition or resolution. Following approval, IOUs, aggregators, DR providers, and other DR stakeholders need time to implement any program changes in their respective technical systems and communicate to customers. This process creates a time crunch to implement changes prior to the following DR season. In this way, PG&E agrees that the AL process is not suitable for more significant ELRP program changes.

Q 65 What is VGIC's basis for recommending that the Commission move up the due date for the ELRP AL from January 15 to November or December?

A 65 VGIC does not explicitly state its rationale for recommending that the Commission move up the deadline for the ELRP AL. However, based on the discussion in the preceding pages of VGIC's testimony, PG&E interprets the rationale behind this request as seeking to maximize the time needed by stakeholders to review the filing as well as the time needed to implement any changes prior to the summer season.[92]

Q 66 Do you agree with VGIC's recommendation to move up the due date for the ELRP AL from January 15 to November or December?

A 66 No, PG&E does not support this recommendation because a November or December due date does not provide sufficient time for PG&E to analyze program performance from the prior season and develop any potential modifications to the program for the following year.

Q 67 Does PG&E propose an alternative process to facilitate inclusive and timely ELRP program updates within a formal regulatory proceeding?

A 67 Yes, in its opening comments on the Phase II ACR, PG&E recommended that the Commission initiate a Phase III of this proceeding starting in 2024 to address implementation of the 2024-2027 DR portfolios.[93] Specifically, PG&E believes that the Commission could issue a Scoping Memo and Ruling for Phase III which explains that it intends to resolve certain ELRP program design issues that may require further refinement prior to adoption on a permanent basis (e.g. eliminating minimum dispatch hours, reducing incentive rates, etc.). The Scoping Memo could include a stakeholder process facilitated by a non-financially interested third party that includes ED Staff, CAISO, CEC, IOUs, CCAs, and other parties to the proceeding to coordinate discussions on these topics. This approach would support ongoing conversations on the future of ELRP that are not constrained by the timing and scope of the existing AL process.

Q 68 What is VGIC's basis for recommending that the Commission allow telematics to be used in ELRP on an interim basis until a new PEV telematics submetering protocol is adopted?

A 68 VGIC states that this would be similar to the approach taken by the Commission regarding electric vehicle supply equipment submetering, where it allowed submetering to be used in ELRP on an interim basis until the final submetering protocol was adopted.[94]

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92 VGIC-1, p. 20, line 15 to p. 22, line 4.

93 PG&E Phase II ACR Opening Comments, April 21, 2023, pp. 1-5.

94 VGIC-1, p. 30, line 12 to line 14.

Q 69 Do you agree with VGIC's recommendation to allow telematics to be used in ELRP on an interim basis until a new PEV telematics submetering protocol is adopted?

A 69 No, PG&E recommends that there is an insufficient record in this proceeding to warrant adoption of the requested change, particularly when the Commission is already addressing the use of telematics as described in D.22-08-024 in R.18-12-006.[95] Although the Commission denied VGIC's request to include modifications to DR programs in R.18-12-006,[96] PG&E believes that the protocols developed through the workshop process ordered in D.22-08-024 should occur prior to implementing modifications to DR programs.[97] Otherwise, there is the potential for policy misalignment between a temporary standard adopted for DR programs and the more comprehensive protocols under development in R.18-12-006.

E. Conclusion

Q 70 What is PG&E's recommendation for 2024-2027 Demand Response Technology Programs and Pilots?

A 70 For the reasons discussed above, PG&E recommends that the Commission adopt PG&E's forecast and program proposals regarding the following issues:

- ADR;
- DRET Program;
- Smart Panel Pilot;
- ELRP Pilot; and
- Ag Pilot

In addition, PG&E recommends that the Commission adopt the following proposals made by parties:

- CLECA's proposal to permit compensation to BIP-ELRP dual participants during non-overlapping events;

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[95] D.22-08-024, OP 7.

[96] D.22-08-024, p. 35.

[97] D.22-08-024, OP 7.

- CEDMC's proposal to eliminate the auto-enrollment requirement for ELRP A.6, with the caveat that the IOUs submit an AL detailing the process for implementing this change;
- VGIC's recommendation to require certain ELRP program design elements to be decided in a formal regulatory proceeding (e.g. changes to minimum dispatch hours, incentive changes), with the caveat that the formal regulatory proceeding is the new Phase III of this proceeding as proposed by PG&E.

PG&E also recommends that the Commission deny the following proposals made by parties:

- Cal Advocates' recommendations to reduce ELRP incentives from $2/kWh to $1/kWh and reduce program hours from 4pm-9pm to 6pm-8pm, starting in 2024;
- CEDMC's proposal to calculate ELRP Group B ILR at the meter level;
- CEDMC's proposal to adopt a 10-hour minimum dispatch requirement for ELRP Group B customers;
- OhmConnect's proposal to establish ELRP as an "on-ramp" to economic DR;
- OhmConnect's proposal to require the IOUs to launch a market awareness campaign;
- OhmConnect's proposal to standardize Flex Alert as the day ahead trigger for all ELRP sub-groups (with optional exclusion of A.1 and A.2)
- VGIC's recommendation to improve flexibility to allow for faster ELRP enrollments;
- VGIC's recommendation to require future changes to ELRP A.5 to be limited to those that are intended to expand participation rather than constrain it;
- VGIC's proposal to move up the due date for the IOUs to submit the Annual ELRP AL from January 15 to November or December of the previous year; and
- VGIC's proposal to allow the use of telematics in ELRP on an interim basis until a new PEV telematics submetering protocol is adopted.

Q 71 Does this conclude your rebuttal testimony?

A 71 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

REBUTTAL TESTIMONY OF CANDICE POTTER

COST EFFECTIVENESS EVALUATION

PACIFIC GAS AND ELECTRIC COMPANY
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REBUTTAL TESTIMONY OF CANDICE POTTER
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A. Introduction

Q 1 What is the purpose of this rebuttal testimony?

A 1 This testimony responds to the direct testimony of the Small Business Utility Advocates.[1] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below.

B. PG&E's Response to Small Business Utility Advocates Recommendation on Cost Effectiveness

Q 2 What is Small Business Utility Advocates (SBUA) recommendation related to cost effectiveness?

A 2 SBUA recommends that the California Public Utilities Commission (Commission) replace the Total Resource Cost (TRC) test with the Societal Cost Test (SCT) as the primary cost effectiveness test for evaluating Demand Response (DR) programs.[2]

Q 3 What is the basis for SBUA's recommendation to replace the TRC test with the SCT as the primary cost effectiveness test for evaluating DR programs?

A 3 SBUA claims that the SCT better reflects the true costs and benefits to society of DR programs because it can include external avoided costs such as reduced greenhouse gas emissions. SBUA also explains that it believes the SCT can accommodate other important externality costs, such as the health impacts from air pollutants, reduced utility bill arrearages, and economic impacts to low income and disadvantaged communities. Lastly, SBUA states that the SCT uses a lower discount rate than the TRC which provides a higher value to long term program benefits.[3]

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[1] SBUA-2.

[2] SBUA-2, p. 2, line 26 to p. 3, line 2.

[3] SBUA-2, p. 3, line 5 to p. 4, line 3.

Q 4 Do you agree with SBUA's recommendation to replace the TRC test with the SCT as the primary cost effectiveness test for evaluating DR programs?

A 4 No, in my direct testimony, I explained that the inclusion of externality benefits in the SCT has potentially broad implications that warrant a thorough analysis and record to vet the valuation of societal costs and benefits and that a broad proceeding such as the Integrated Distributed Energy Resources (IDER) proceeding (Rulemaking (R.) 14-10-003) would be an appropriate venue for this assessment.[4]

Q 5 Is the Commission conducting such an assessment of the SCT in a broad proceeding such as the IDER?

A 5 Yes, the Commission issued R. 22-11-013 in November 2022 as the successor to the IDER proceeding. In R.22-11-013, the Commission intends to determine whether to adopt the SCT, and if so, how to best apply the results of the SCT into the DER cost effectiveness framework.[5]

C. Conclusion

Q 6 What is your recommendation regarding SBUA's proposal to replace the TRC test with the SCT as the primary cost effectiveness test for evaluating DR programs?

A 6 I recommend that the Commission deny SBUA's proposal because the Commission is currently assessing the use of the SCT for DER customer programs in R.22-11-013.

Q 7 Does this conclude your rebuttal testimony?

A 7 Yes, it does.

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4 Exhibit (PG&E-2), Chapter 9, p. 9-11, line 11 to line 19.

5 R.22-11-013, p. 19.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NEDA ASSADI[1]

Q 1 Please state your name and business address.

A 1 My name is Neda Assadi, and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California 94612.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Product Manager in the Engineering, Planning and Strategies, Utility Partnerships and Innovation, Clean Energy Programs Department at PG&E. In this position, my responsibilities include developing PG&E’s load management strategy and dual participation policy. I have previously been responsible for policy development of third-party demand response (DR) in various California Public Utilities Commission proceedings and Electric Rule 24 in the Click-Through Application 1811015 and the policy and administration of the DR Auction Mechanism pilot.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in International Studies with concentrations in Political Science and Economics from the University of California – San Diego, La Jolla, California; and a Master of Arts degree in Energy, Resources, and the Environment and International Economics from the Johns Hopkins University Paul H. Nitze School of Advanced International Studies, Washington, District of Columbia.

I joined PG&E in 2015 in the DR Department, and prior to joining PG&E, I worked in financial, economic, and strategic consulting, including supporting the World Bank on energy access policy in rural areas.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and rebuttal testimony in PG&E’s 2023-2027 Demand Response Program Application:

- Testimony, Exhibit (PG&E-2), “2024-2027 Full Proposal”:
  - Chapter 1, “The Landscape of Demand Response and Summary of Proposals”:
    - Sections B, C.1, and C.2; and

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[1] Formerly Oreizy. This SOQ is being resubmitted to reflect this change.

- Chapter 2, "Program Policy Enhancements":
  - Section B.1
  - Section C.
- Rebuttal Testimony:
  - Chapter 1, "Program Policy Enhancements":
    - Section C, C.2, and C.3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOHN LIN

Q 1 Please state your name and business address.

A 1 My name is John Lin and my business address is Pacific Gas and Electric Company, 300 Lakeside Drive, Oakland, California 94612.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Product Manager in Customer Care within Engineering, Planning and Strategies, Clean Energy Programs, Data and Energy Product Management team at PG&E. I have been a product manager at PG&E since June 2016 and have supported the Share My Data service since 2018.

Q 3 Please summarize your educational and professional background.

A 3 I have my doctorate degree in physics for quantum electronics from Osaka University in Japan, a masters in plasma physics from University of Texas at Austin, and a bachelor's in physics from Cornell University. I have been with PG&E for the past 7 years, first managing the Stream My Data service, and now include Share My Data, and Building Benchmarking services. Prior to PG&E, I was founder, executive, and board member of Wireless Glue Networks, Inc. and led engineering and sales of demand side management technologies, including design, development, and deployment of OpenADR 2.0b demand response software, and Smart Energy 1.1 profile home area network solutions both domestically and internationally.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following rebuttal testimony in PG&E's 2023-2027 Demand Response Programs Application:

- Chapter 1, "Program Policy Enhancements":
  - Section D.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.