Application: 20-11-003
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Date: September 10, 2021
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

EMERGENCY RELIABILITY OIR

REPLY TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
EMERGENCY RELIABILITY ORDER INSTITUTING RULEMAKING
REPLY TESTIMONY

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CHAPTER 1
SUMMARY OF REPLY TESTIMONY IN PHASE 2 OF THE EMERGENCY RELIABILITY RULEMAKING

A. Introduction

Pacific Gas and Electric Company (PG&E) is pleased to provide this summary of its Phase 2 reply testimony in Rulemaking 20-11-003.

PG&E notes that close to 50 parties submitted Phase 2 opening testimony, which limited time to fully assess all proposals in the nine days available to review and prepare reply testimony. That said, PG&E observes that a multitude of parties advanced proposals that would have either limited impacts or impacts that are difficult to evaluate in the context of bringing a material level of resources to bear in the 2022-2023 period. Certain parties advanced proposals that have already been raised in other forums or would not result in additional reliable resources in the period of interest in the instant Phase of this proceeding. Other proposals involved complex ideas or the need to leverage nascent technologies, making quick implementation or meaningful benefits overly challenging and potentially infeasible. To achieve the goals of Phase 2 of this proceeding, PG&E recommends that the California Public Utilities Commission (CPUC) focus on assessing proposals based on potential impact and ease and speed of implementation.

Section B of this chapter summarizes PG&E's demand side reply testimony, which is included in subsequent Chapters 2, 3, 4, 5 and 6. Section C of this chapter summarizes supply side reply testimony, which is included in subsequent Chapter 9. PG&E continues to support proposals contained in its September 1, 2021 opening testimony (as amended and restated in its entirety by its errata testimony served on September 2, 2021) (PG&E Opening Testimony), even if they are not addressed in this reply testimony. Finally, Section D of this chapter addresses a core gas proposal that PG&E presented in its PG&E Opening Testimony.

B. Demand Side

By PG&E's account, opportunities to expand participation by residential customers should be the focus of the Phase 2 OIR Reliability Decision. The current Emergency Load Reduction Program (ELRP), while not perfect, serves as a starting point for expanding emergency Demand Response (DR). Calls by parties to try alternative offerings or side-step ELRP at this point are both premature and unwise because: (1) the ELRP has just launched and it needs time to build up, and (2) there is a lead time in setting up a new program/pilot and to recruiting new participants – something that many may forget.

PG&E is also proposing incremental modifications to its existing DR portfolio in order to address concerns raised by the CPUC in terms of responsiveness and attrition. These modifications follow from Phase 1, which was focused on 2021, to now include 2022 and 2023. Separately, there are opportunities for fine-tuning in the realm of Integrated Demand Side Management and Distributed Energy Resources by optimizing policy for programs (e.g., coordination between Energy Efficiency and DR delivery). However, PG&E cautions that in some cases new technologies while having great promise longer term, are not expected to meaningfully contribute to meeting grid needs in the next two years. Therefore, the focus should be on tried and true measures, which may have less complexity and appeal, but could provide the grid support that we all seek.

This material was prepared by me, Sebastien Csapo, or under my supervision. Insofar as this material is factual in nature, I believe it to be true. Insofar as this material is in the nature of opinion or judgment, it represents my best judgment. I adopt this testimony as my sworn testimony in this proceeding.

C. Supply Side

PG&E appreciates the carefully considered opening testimony of parties provided in response to the Energy Division Staff Concept Paper (SCP). Parties demonstrated a desire to build upon the solutions-oriented approach offered in the SCP to address supply constraints while continuing to facilitate California's climate and affordability goals. In Chapter 9 of this reply testimony, PG&E replies to parties' opening testimony on the SCP. PG&E also offers supportive reply testimony in Chapter 9 related to opening testimony of those parties that oppose penalties for Decision 19-11-016 procurement. In addition, PG&E opposes Western Power Trading Forum's opening testimony suggesting that investor-owned utility shareholders should be responsible for procurement penalties. PG&E further replies in agreement with recommendations in opening testimony for continued use of an expedited procurement approval framework to ensure that resources capable of serving load during the net peak are brought on expeditiously and reiterates its support for interim modifications to the central procurement entity framework that will streamline the procurement process. Finally, PG&E replies in opposition to party recommendations for prescriptive procurement requirements that are inconsistent with the goals of this proceeding.

This material was prepared by me, Gillian Clegg, or under my supervision. Insofar as this material is factual in nature, I believe it to be true. Insofar as this material is in the nature of opinion or judgment, it represents my best judgment. I adopt this testimony as my sworn testimony in this proceeding.

D. Gas

PG&E in its reply testimony acknowledges the interest in fueling backup generation with cleaner burning natural gas including renewable natural gas versus diesel. However, PG&E identifies risks and impediments to achieving this needed support of the California Independent System Operator (CAISO) grid and reduction in emissions. Without the proposed Core Gas Transportation option, customers cannot obtain the reliability needed to choose gas instead of diesel. Also, for this to be an economically viable option for PG&E's customers, given the required investments, short-term participation in supporting the CAISO grid does not provide a feasible opportunity.

PG&E's proposed change provides a rebalancing of our rules and tariffs to meet today's needs in support of CAISO stability, our customer's needs, and California and PG&E's shared goal for emission reduction.

This material was prepared by me, Katy Lamb, or under my supervision. Insofar as this material is factual in nature, I believe it to be true. Insofar as this material is in the nature of opinion or judgment, it represents my best judgment. I adopt this testimony as my sworn testimony in this proceeding.

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CHAPTER 2

EMERGENCY LOAD REDUCTION PROGRAM

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CHAPTER 2
EMERGENCY LOAD REDUCTION PROGRAM

A. Introduction

Pacific Gas and Electric Company (PG&E) provides rebuttal testimony in response to opening testimony filed by parties related to the Emergency Load Reduction Program (ELRP). Section B of this chapter addresses proposed modifications to the current adopted ELRP while Section C addresses issues raised by parties for a residential ELRP, which PG&E refers to as A.5.

B. Responses – Modifications to Current ELRP

Q 1 Can PG&E clarify its position on the use of Automated Demand Response (AutoDR) funds for enabling ELRP participation?

A 1 PG&E in its Phase 1 Opening Testimony[1] advocated for the expansion of AutoDR incentives to ELRP. As part of that expansion, PG&E proposed revamping the incentive structure to be 100 percent upfront conditioned on a five-year commitment to participating in a demand response (DR) program/pilot. This position is consistent with the one advocated by Southern California Edison Company (SCE) in its Phase 2 Opening Testimony.[2]

Q 2 Can PG&E comment on input provided by stakeholders on the current ELRP's limitation for compensating dually enrolled Base Interruptible Program (BIP) participants during *non-overlapping* events (i.e., "Special Considerations" parts a. and b.)?

A 2 A number of stakeholders[3] expressed the same concern that PG&E expressed in its Opening Testimony to Phase 2 pertaining to the disincentive for BIP participants to dually enroll with ELRP. This disincentive was enshrined in the Phase 1 decision.[4] While PG&E agrees that

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1 PG&E Opening Testimony, Phase I, Ch. 3, pp. 3-8–3-9.

2 SCE Opening Testimony, p. 40-42.

3 SCE Opening Testimony, p. 35-36; Voltus Opening Testimony, p. 9-10; Joint DR Parties Opening Testimony, p. 8.; California Solar & Storage Association Opening Testimony, p. 8.

4 D.21-03-056, Attachment 1, p. 10, "Special Considerations."

overlapping or dual compensation should be minimized, the Special Considerations provision precludes ELRP compensation during *non-overlapping* events. Consequently, PG&E has seen very limited enrollment by BIP participants in ELRP.[5] PG&E believes removal of the "Special Considerations" provisions a and b would increase interest by BIP participants in ELRP.

Q 3 Can PG&E share its perspective on ELRP offering a reservation (capacity) payment for ELRP participation?

A 3 While several stakeholders[6] express a desire for ELRP to offer a capacity payment for participation, this idea goes against the fundamental design of ELRP set forth by the California Public Utilities Commission (CPUC) as "voluntary" and "out-of-market." Since there are no penalties associated with responding to an ELRP dispatch notification, PG&E questions the appropriateness of offering a capacity payment in addition to the current energy payment. Indeed, if potential DR participants seek to obtain capacity payments as part of participation in a DR program, then PG&E offers the ability to do so through its existing Capacity Bidding Program (CBP) and BIP tariffs. Lastly, under the proposals in the Staff Concept Paper, if participants *demonstrate* the need for higher compensation in ELRP, then the CPUC still has the discretion to adjust the energy incentive.[7] Therefore, PG&E believes the CPUC should not offer a capacity payment for ELRP participation.

Q 4 Can PG&E comment on the viability of utilizing sub-metering for ELRP, including the California Independent System Operator's (CAISO) Meter Generator Output framework in response to Opening Testimony filed by the AEE?[8]

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5 Enrollment by BIP participants in ELRP has been less than 1 percent based on service accounts.

6 Sunrun Opening Testimony, p. 17; Advanced Energy Economy (AEE) Opening Testimony, p. 3-4; Voltus, Opening Testimony, p. 7; Joint DR Parties Opening Testimony, p. 24, line 3.

7 Energy Division Staff Concept Paper dated August 16, 2021, pp. 3-4.

8 AEE, Opening Testimony, p. 6, lines 8-18.

A 4 PG&E points out that sub-metering and settling at the device level, while possible at the wholesale level, is not currently feasible on a large scale at the retail level, i.e., behind-the-meter. Currently, settlement occurs at the retail meter associated with the location (premise) rather than at the distributed energy resource level behind-the-retail meter. The development of rules and the associated infrastructure for device level settlement for retail purposes would be a significant, multi-year effort that would involve significant resources. Therefore, PG&E believes that it is not appropriate to use behind-the-meter sub-metering for ELRP at this time.

Q 5 Can PG&E respond to the claim made by Voltus that ELRP has "resulted in minimal enrollment" and "has not secured the necessary grid reliability, as predicted when the program was proposed."[9]

A 5 PG&E asserts that the claim made by Voltus is both inaccurate and premature. First, it is PG&E's understanding that ELRP enrollment metrics are at this time not publicly disclosed, so it's unclear how Voltus can make this claim. Second, the ELRP is still scaling and, for PG&E, recently expanded the ability to enroll via ELRP A.3 (Distributed Energy Resource (DER)) and A.4 (Virtual Power Plants (VPP)), which it believes could be a significant source of additional participation. Third, the program season is still open and will close at the end of October, after which PG&E will be able to tally both ELRP Group A and Group B enrollments and participation.[10] Lastly, PG&E points out that Group A enrollments as of September 7, 2021, are about half of PG&E's current BIP program by megawatts (MW).

Q 6 Can PG&E comment on the Joint Parties' call for "expedited interconnection review"?[11]

A 6 While PG&E did accelerate the export options under ELRP from the requested 2022 to August 2021, it is not clear at this point what level of interest and availability exists among participants. PG&E notes that the Rule 21 interconnection process is complicated because each application is unique and is site dependent. Therefore, a uniform, scaled process for

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9 Voltus, Opening Testimony, p. 7; Joint DR Parties, Opening Testimony, p. 2, lines 2-3.

10 Group B participation by third-party DRPs is only known once the utility is invoiced.

11 Joint Parties, Opening Testimony, p. 5, lines 5-12.

assessing all projects may not be viable or warranted. Ensuring safety and reliability is paramount. Separately, the seasonal (May – October) and limited term (2021–2025) of ELRP poses additional limitations, including cost viability for potential participants. PG&E appreciates the Joint Parties' acknowledgement that actions to address an expedited process would require additional resources and staffing.

Q 7 Can PG&E share its observation related to the Joint Parties' recommendation of expanding Group B to non-DR participants?[12]

A 7 PG&E is unclear whether this recommendation by the Joint Parties was intended to address the current non-residential ELRP or a future residential ELRP (A.5). PG&E points out that non-DR, non-residential participants have a pathway today to participate via A.1. As for a future residential ELRP (A.5) option, it's unclear what incremental benefit would be derived by having multiple third-party DRPs/Aggregators administering the ELRP.

Q 8 Can PG&E comment on the California Solar and Storage Association's (CALSSA) proposal that PG&E provide an Application Programming Interface (API) access to all customer locations subject to Public Safety Power Shutoff (PSPS) events who are in ELRP?[13]

A 8 PG&E points out that customers impacted by PSPS are notified of PSPS events through email, phone, and text notifications based on three conditions: Watch, Warning, and Update.[14] Separately, each customer has the ability to look up their location online to see whether it may be impacted by a PSPS.[15,16] All told, the development of an API that accomplishes essentially the same thing does not appear to be a good use of resources, especially since the ELRP is a termed pilot and participants may be

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12 Joint Parties (CEDMC, ecobee, Leapfrog Power, Oracle), Opening Testimony, p. 13.

13 CALSSA, Opening Testimony, pp. 11-12.

14 Link: https://www.pge.com/en_US/residential/outages/public-safety-power-shuttoff/psps-updates-and-alerts.page#notification.

15 Link: https://pgealerts.alerts.pge.com/updates/.

16 Due to customer privacy, PG&E only provides the actual location of impacted customers including customers in its medical baseline program to Public Safety Partners via the secured Portal under a confidentiality agreement. PG&E does not provide customer specific addresses outside of Public Safety Partners under privacy rules.

transitory. Moreover, implementation of an API would require that data security assessments be conducted, which have additional costs to both PG&E and the potential participants.

Q 9 Can PG&E comment on CALSSA's proposal for a new Group C option for ELRP that appears to utilize storage.[17]

A 9 It is not clear to PG&E why the existing A.3 (DERs) and A.4 (VPP) options are insufficient and merit an additional participation option. CALSSA's proposal only adds complexity and cost to an already complex set of participation alternatives. That said, the proposed Group C option appears to have significantly different program requirements, including a shorter 50 hour per year limit, a proposed incentive payment, no dual participation restriction, and a complex invertor level settlement. All told, the proposed Group C would no longer resemble the adopted ELRP attributes per Decision (D.) 21-03-056. Ultimately, the ELRP—like other DR programs—should not try to pick and choose between different technology types for supporting grid needs. Rather, a uniform requirement should apply to all participants without favoring one technology type over another.

Q 10 Can PG&E comment on OhmConnect's support for higher incentives for customers on California Alternate Rates for Energy (CARE) and those living in disadvantage communities[18]

A 10 PG&E believes that compensation should be uniform across all ELRP options without favoring one set of participants over another. While PG&E recognizes that participants may be receiving incentives from other programs that provide either a direct or indirect financial benefit (e.g., CARE, ESA)[19] or facilitate participation in DR or Energy Efficiency programs (e.g., Smart Thermostats), PG&E does not support different compensation rates for ELRP, either between customer classes (e.g., non-residential vs. residential) or within a customer class.

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17 CALSSA, Opening Testimony, pp. 4-11.

18 OhmConnect indicates support for higher incentives for customers on CARE and those living in disadvantage communities. *See* OhmConnect, Opening Testimony, p. 8.

19 CARE provides a discount on utility bills for income qualified customers while ESA provides energy efficiency measures. More information can be found at: https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/longer-term-assistance/care-esa/care-esa.page?WT.mc_id=Vanity_savenow.

Q 11 Can PG&E provide an assessment of the proposed Electric Services Capacity Tariff (ESCT) by the Microgrid Resources Coalition?

A 11 PG&E observes that the ESCT is a very complex and prescriptive proposal that would require significant effort to both scope and implement. For instance, it calls for modifications to Rule 2, the interconnection process and other policy considerations (e.g., waiver of departing load and standby charges) that would require input by the Investor-Owned Utilities (IOU), stakeholders and the CPUC. Moreover, the call to remain on the tariff for "25 years" seems misguided from both a customer experience perspective and the CPUC's request to address short-term need for 2022 and 2023. That said, it's not clear why the ESCT tariff is needed, as the ELRP and the BIP tariff are well suited to support emergency needs. While the ESCT proposal appears to focus on enabling participation by storage, PG&E points out that the ELRP allows for participation through the A.3 enrollment channel. Similarly, since the proposal would also allow for provisioning during the net peak hours, presumably outside of any emergency events, then PG&E's current CBP tariff would be a suitable program for participants that expect to be dispatched more frequently. Separately, the ESCT posits that "at least 1,000 MW could be brought to bear",[20] which does not appear to be supported by anything more than a "professional belief." All told, PG&E observes that the proposed ESCT does not offer a value proposition that merits consideration.

C. Responses – Addition of a Residential ELRP Option (A.5)

Q 12 OhmConnect cited the California Energy Commission's (CEC) findings stating that the greatest reductions came from "energy engaged" customers such as those with solar panels, plug-in vehicles, or load automation devices. Does PG&E agree with this recommendation?

A 12 Yes. PG&E agrees with OhmConnect and CEC that engaged customers are more likely to enroll and be successful in DR programs. Therefore, in both PG&E's Emergency Reliability OIR Phase 2 ELRP Residential proposal and Emergency Reliability OIR Phase 1 refresh of the Power Savers Reward Pilot, PG&E proposed to offer personal communications versus the

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[20] ESCT Opening Testimony, p. 19.

broadcast messaging of Flex Alerts as personal notifications typically results in greater participation. Additionally, personal, targeted notifications will result in less confusion, given that some customers are already participating in a DR program or may have recently received notifications to transition to a Time-of-Use rate.

Q 13 Are San Diego Gas & Electric Company (SDG&E) and SCE proposing residential programs similar to PG&E's proposals of Power Saver Rewards Pilot or the combination of Residential ELRP Option (A.5) and BYOT under SmartAC?

A 13 There are core similarities, along with some differences, among the IOU proposals, such as the combination of behavioral DR and technology dispatch, personalized communications, performance-based incentives using meter data, and CAISO alerts, warnings and emergency dispatch triggers. An important point that PG&E raises is that both the PSRP and enhancements to its SmartAC would incorporate BYOT, which is currently offered by both SCE and SDG&E. PG&E defers to the CPUC to ascertain the most appropriate approach or approaches to implementing larger-scale DR programs for the residential population and discusses the options further in Chapter 3.

Q 14 Can PG&E provide an assessment of an open enrollment for ELRP per OhmConnect's Opening Testimony?[21]

A 14 As a threshold clarification, PG&E interprets the open enrollment to be limited to the residential ELRP (A.5) offering based on the CPUC's Staff Concept Paper. Also, it was not clear to PG&E if the reference to "ELRP Administrators" was referencing the utilities or a broader set of providers (IOUs, Community Choice Aggregators, Demand Response Providers (DRPs)). PG&E cautions that an "open enrollment" process, which could potentially target up to 3 million participants,[22] would be impractical and costly to undertake. Furthermore, if the "ELRP Administrator," is limited to the utilities, then PG&E would not be amenable to promoting third-party

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[21] OhmConnect, Opening Testimony, p. 4, Step #1.

[22] PG&E, Opening Testimony, p. 2-9, line 12.

DRP offerings because ratepayers are not expected to fund activities to promote marketing and enrollments for third-party DRPs.

D. Witness

Q 15 Was this material prepared by you or under your supervision?

A 15 Yes, it was prepared by me Sebastien Csapo.

Q 16 Insofar as this material is factual in nature, do you believe it to be correct?

A 16 Yes, I do.

Q 17 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 17 Yes, it does.

Q 18 Do you adopt this testimony as your sworn testimony in this proceeding?

A 18 Yes, I do.

Q 19 Does this conclude your reply testimony?

A 19 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

POWER SAVER REWARDS PILOT

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CHAPTER 3
POWER SAVER REWARDS PILOT

A. Introduction

Pacific Gas and Electric Company (PG&E) provides reply testimony in response to opening testimony filed by parties related to the Power Saver Rewards Pilot (PSRP) and Residential Emergency Load Reduction Program (ELRP) (A5).

B. Responses

Q 1 Does PG&E have a preferred approach in implementing either PSRP or ELRP A.5 and SmartAC Bring Your Own Thermostat (BYOT)?

A 1 PG&E originally presented a bifurcation of its PSRP in Opening Testimony with behavioral DR under ELRP A.5 and BYOT under SmartAC. In addition to resubmitting the PSRP pilot, PG&E expressed deference to the California Public Utilities Commission (CPUC) on a particular approach. Now, after reading the opening testimonies of SCE and SDG&E, PG&E believes proceeding with ELRP A.5 for a targeted group of customers and adding Smart Communicating Thermostats (SCT) to SmartAC would achieve the overarching objectives of the Emergency Reliability Order Instituting Rulemaking in providing greater load reduction value to support the grid. However, as identified in prior questions pertaining to behavioral DR, there are implementation differences and choices that have implications on timeline and budget. PG&E suggests that, rather than prescribing a unilateral approach, the CPUC could permit a variety of pilot proposals by the IOUs to proceed and assess outcomes in 2023.

Q 2 What are the high-level similarities and differences between the various behavioral demand response (DR) program proposals offered by the Investor-Owned Utilities (IOU)?

A 2 The base design of each of the IOU residential DR program proposals is quite similar: auto-enrolling a population of customers to receive event day communications. The primary variances are (1) who is enrolled and receives the communications, and (2) whether incentives will be provided.

The targeted population impacts the customer counts, and subsequently the costs. The following table summarizes the approaches.

TABLE 3-1
IOU BEHAVIORAL DR PROGRAM COMPARISON

Line No.		PG&E		SCE[(a)]	SDG&E[(b)]
1	Program Name	Power Saver Rewards Pilot	ELRP A.5	Whole Home Saving Program	Peak Day
2	Enrollment	Auto-Enroll	Auto-Enroll	Auto-Enroll	Auto-Enroll
3	Population	Home Energy Report Recipients	With or Without Community Choice Aggregation	High Usage Customers	Home Energy Report Recipients
4	Est. Customer Count	1.6 million	1.6 million or 3.0 million	3.0 million	525,000
5	Personalized Notifications	Yes	Yes	Yes	Yes
6	Incentive	Low Income & DAC	All	All	None
7	Est. Load Reduction Value	55 megawatt (MW)	96 MW or 180 MW	100-160 MW	18 MW
8	Budget Request	$27.3 million	$29.1 million or $44.6 million	$73.9 million	None

(a) Southern California Edison Company (SCE).
(b) San Diego Gas & Electric Company (SDG&E).

Q 3 Would targeting customers who have chosen to receive high usage notifications be a more beneficial approach to serve as the auto-enrolled population?

A 3 It could be more beneficial to target high usage customers. PG&E has learned throughout the years of SmartRate implementation that customers who sign up for notifications do perform better than those who do not. SCE's Opening Testimony highlighted its experience with the implementation of Peak Time Rebate, stating that "customers who had opted into notification emails with the utility are more engaged and will provide more load reduction."[1] To this end, PG&E would explore including high usage customers who have opted to receive notifications as of as one

1 SCE, Opening Testimony, p. 8 line 14.

of the populations when targeting customers. However, it's important to note that the High Usage Surcharge alerts and letters will be discontinued in the third quarter of 2022 after the residential TOU transition ends.

Q 4 Does paying auto-enrolled customers guarantee higher performance?

A 4 The Staff Concept Paper presented the idea to pay incentives to all behavioral DR participants, which is in contrast to SDG&E's no-incentive and PG&E's PSRP targeted-incentive approaches. In scoping for the ELRP A.5 proposal, PG&E discussed the differences in the load reduction value with Oracle and learned that offering incentives can increase peak savings by two to three times in this type of program.

Q 5 How would PG&E identify disadvantaged communities (DAC) customers for enrollment in PSRP Option A?

A 5 In supplemental testimony of PSRP, PG&E had proposed to offer incentives to low-income and customers in DAC. PG&E has analyzed all of its territory and has identified 550 census tracts that meet the definition as DAC according to the California Environmental Protection Agency Health and Safety Code Section 39711.

Q 6 What are operational considerations with implementing a pay for performance type of program?

A 6 To stand-up a program that involves such a high volume of customers, PG&E would engage with an experienced industry leader. Establishing system integrations to support the flow of meter data, which enable performance calculations, does require time and Information Technology (IT) resources. PG&E has existing relationships with vendors who already have this data flow, so proceeding with one of them presents considerable labor and cost efficiencies. However, in order to ensure this program is available by the end of May of 2022, PG&E must contract for this scope of work with a vendor as soon as possible. The costs of IT integrations were included in PG&E's budgets under the Administrative category.

Q 7 Why has PG&E chosen electronic gift cards as the method to remit incentive payments to customers?

A 7 Residential DR programs around the country offer incentive payments to customers in various formats including bill credits, electronic gift cards, donation options, and redemption toward material items. PG&E has consulted with industry leaders to identify the leading trends and preferences and electronic gift cards is the most popular and results in high customer satisfaction ratings. Further, PG&E's own customer research has surfaced that bill credits can be overlooked by customers while an electronic gift card puts virtual cash in customer wallets very noticably. Bill credits require extensive IT infrastructure to implement and itemize on customer bills.

C. Witness

Q 8 Was this material prepared by you or under your supervision?
A 8 Yes, it was prepared by me, Wendy Brummer.
Q 9 Insofar as this material is factual in nature, do you believe it to be correct?
A 9 Yes, I do.
Q 10 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 10 Yes, it does.
Q 11 Do you adopt this testimony as your sworn testimony in this proceeding?
A 11 Yes, I do.
Q 12 Does this conclude your reply testimony?
A 12 Yes, it does.

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CHAPTER 4

EXISTING DEMAND RESPONSE PROGRAMS

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EXISTING DEMAND RESPONSE PROGRAMS

A. Introduction

Pacific Gas and Electric Company (PG&E) provides this reply testimony in response to opening testimony filed by parties related to PG&E's existing demand response (DR) programs, including the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), SmartAC, along with other related matters pertaining to Automated Demand Response (AutoDR) and Dual Participation.

B. Responses to BIP

Q 1 Can PG&E respond to recommendations made by Voltus and the Joint DR Parties[1] to modify the BIP tariff?

A 1 Yes. While Voltus claims that the "aggregators' BIP portfolios have shriveled due to the punitive penalties combined with the wildly unpredictable number of dispatches,"[2] PG&E believes this statement is misplaced. First, PG&E notes that BIP is an "emergency" Day-Of program that was intended to be available 24 hours per day, seven days per week to meet grid needs. As such, it offers both a healthy carrot and a long stick to incentivize performance. That said, a participant would incur an excess energy charge (i.e., penalty) if it does not drop down to its Firm Service Level (FSL). Therefore, participants are expected to pick an FSL that reflects their ability to perform since the ongoing incentive is a function of the FSL.

Recognizing that BIP was deployed more frequently in 2020 than in prior years, PG&E proposed in its Phase 1 testimony to raise the incentive level by $1.50/kilowatt (kW) across the board for BIP participants. This proposal was adopted by the decision in Phase 1 of this proceeding, Decision (D.) 21-03-056.[3] Now recognizing that the summer period has a greater

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[1] The Joint DR Parties are CPower and Enel X North America, Inc.

[2] Voltus Opening Testimony, p. 5, lines 11-12.

[3] D.21-03-056, Attachment 1, p. 18.

probability for dispatch for the near term, PG&E is proposing to increase incentives for May-October by another $1/kW.[4] At the same time, PG&E has not advocated to raise its excess energy charge (penalty) of $6/kW, which it believes is appropriate in light of the higher incentives. Separately, Voltus advocates for greater "flexibility" for non-summer months.[5] While PG&E is not opposed to revisiting programmatic elements, it believes such issues might be better suited to be deliberated in the next DR Funding Application, where a more informed evidentiary record could be developed.

Separately, the Joint DR Parties call for a bump in the BIP incentive level by 30 percent through 2023. In response, PG&E notes that if the additional seasonal increase of $1/kW is approved by the California Public Utilities Commission (CPUC), the incentive level would increase by 28 to 31 percent based on the BIP incentive level prior to the issuance of D.21-03-056 (which raised it by $1.50/kW).

PG&E disagrees that lowering of the excess energy charge – especially by 75 percent – is warranted, as called for by the Joint Parties. As explained earlier, it is important for the BIP to have a "long stick" to ensure parties drop down to their FSL. PG&E believes that any lowering of the excess energy charge should be tied to a commensurate lowering of the incentive.

Q 2 Can PG&E comment on the proposal by California Large Energy Consumers Association (CLECA) to reintroduce the Demand Bidding Program (DBP),[6] which was previously shut-down due to the challenges with market integration?

A 2 Overall, PG&E believes that Emergency Load Reduction Program (ELRP) serves the purpose of DBP and questions whether introducing another similar program is warranted. As a side note, PG&E had taken the prior DBP tariff as a starting point for developing its proposal in Phase 1 of the instant proceeding. PG&E believes that ELRP has substantial similar attributes to DBP. Furthermore, adding a similar program could result in

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4 PG&E Opening Testimony, p. 4-2 to 4-3.

5 Voltus Opening Testimony, p. 6, lines 3-14.

6 CLECA Opening Testimony, pp. 3-5.

participants simply shifting from one program to the next rather than obtaining incremental megawatts (MW). Plus, it should not be underestimated that the roll-out of a new DR offering takes both resources and time, which could be better directed at pursuing other areas that may address a void. In conclusion, with the availability of CBP, BIP, ELRP and California State Emergency Program (until end of October 31, 2021), PG&E questions whether it makes sense to have yet an additional program.

Q 3 Can PG&E comment on Enchanted Rock's proposal for a "ten-year BIP contract term."[7]

A 3 PG&E does not fully understand the proposal as it's not clear if it is intended to replace the current non-contract based BIP tariff[8] into what ostensibly appears to be a Power Purchase Agreement. Based on PG&E's limited understanding, PG&E has concerns with any effort that would convert the BIP tariff, which provides for open enrollment with the ability to unenroll, into a 10-year termed contract. Separately, the proposal references a "current market rate for BIP" (p. 5), which PG&E doesn't understand because the compensation rate for BIP has been administratively set by the CPUC and no market rate exists. Furthermore, it's not clear why Enchanted Rock advocates that resources obtained under its proposal would *not* count towards the DR Reliability Cap[9] if these resources fall under the emergency DR framework.[10]

Q 4 What is PG&E's position on expanding the pool of eligible fuels for use by backup generators?

A 4 PG&E shares the sentiment[11] expressed by stakeholders that actions that enable conversion of existing backup diesel resources to ones that can

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7 Enchanted Rock Opening Testimony, pp. 5-6.

8 PG&E notes that BIP participants can enroll directly with PG&E or through an Aggregator. Enrollments with an Aggregator would be subject to the terms and conditions set forth by the BIP Aggregator Agreement, a standardized tariffed. See Form 79-1079 at pge.com: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_FORMS_79-1079.pdf.

9 Enchanted Rock Opening Testimony, p. 6.

10 DR resources considered to be for emergency are capped. This cap was raised to 3 percent in the Phase 1 Decision. See D.21-03-056, p. 31.

11 Enchanted Rock Opening Testimony, p. 8; Joint DR Parties Opening Testimony, pp. 27-28; Joint Parties Opening Testimony, p. 30.

utilize cleaner sources of fuels, including pipeline-quality natural gas and renewable fuels, deserve attention. Specifically, expanding CPUC Resolution E-4906's fuel conversion options, which is limited to California Air Resources Board certified liquid fuels, to a broader set up fuels, including renewable natural gas and other green feedstock should be considered.

C. Response to CBP

Q 5 Can PG&E comment on the Joint DR Parties'[12] and the Joint Parties'[13] positions related to a number of baseline issues, including the utilization of the 5-in-10 baseline for non-residential participants, removal of the +/-40 percent adjustment cap, and expand the CAISO's wholesale baseline options utilized for capacity to energy payments?

A 5 PG&E points out that while the 5-in-10 baseline was recently expanded for use by residential participants, it's not clear if such an expansion to non-residential participants is warranted. Historically, the 10-in-10 baseline has been the optimal methodology for measuring performance. Similarly, it's not clear if removing the +/-40 percent adjustment cap is warranted at this point. As PG&E understands, changes to the baseline methodology were intended to be addressed in the next five year funding cycle (2023-2027) based on the current DR Funding Decision for 2018-2022.[14] As part that process, D.19-07-009 called for the establishment of a Retail Baseline Working Group (RBWG), which was tasked with preparing and serving a report. This report was to be included in the Investor-Owned Utilities (IOU) 2023-2027 DR Application for consideration.[15] Similarly, the Joint Parties call for the expansion of wholesale baseline options for utilization in energy CBP settlement.

PG&E believes there should be a process for assessing the efficacy of the proposed baselines before expanding the broader suite of baselines.

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[12] Joint DR Parties Opening Testimony, pp. 12-13.

[13] Joint Parties Opening Testimony, pp. 11 and 30-31.

[14] D.17-12-003, p. 186, Conclusion of Law 74.

[15] D.19-07-009, Ordering Paragraph 19, identified issues for the RBWG to address and specified the need to include the report in the 2023-2027 DR Funding Application. Separately, D.19-07-009 called for the report to be served to the service list by April 1, 2021, *see* p. 86. This report was served by PG&E on behalf of the RBWG on March 1, 2021.

Moreover, the implementation of additional baseline options requires both process and system changes that involve time and financial resources. Rather than addressing piecemeal baseline issues in this expedited Rulemaking, PG&E suggests that the next DR Application process would be the best forum for assessing baseline issues in a comprehensive manner.

D. Response to SmartAC

Q 6 Could PG&E provide insights into the expansion of the SmartAC program to include smart communicating thermostats (SCT)?

A 6 PG&E hereby provides further details on the expansion of the SmartAC program to include SCT.

PG&E's proposal estimated 56,646 new SCTs in 2022 and 43,906 in 2023. The cost of SCTs offered through the online store are represented within the Incentive line item of Table 4-4:[16] $1,481,620 in 2022 and $1,481,620 in 2023. These values represent the SmartAC program cost, which will subsidize $70 per SCT. The AutoDR program will cover an additional $50 to ensure near 100 percent subsidy. Customers will be responsible for paying sales tax and shipping.

The Incentive line item is comprised of the following elements:

TABLE 4-1
SMARTAC BUDGET

Line No.		2022	2023
1	Enrollment Incentive	$1,705,500	$1,705,000
2	SCT Subsidy	1,481,620	1,481,620
3	Annual Incentive	1,288,697	2,287,558
4	Total	$4,475,817	$5,474,678

Because PG&E has not previously offered its own SCT DR program, PG&E does not have underlying assumptions on how long participants will remain in the program.

IT expenses associated with implementing the program were incorporated in the Administrative line item[17] of Table 4-4 and are estimated

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16 PG&E Opening Testimony pp. 4-10, Table 4-4 line 9.

17 PG&E Opening Testimony pp. 4-10, Table 4-4 line 4.

at $200,000 per program year. This is based on the fact that an existing API from the primary DR system, Demand Response Market Integration (DRMI), could quite readily be leveraged and other enhancements would be relatively minor to communicate with a third-party vendor system. This cost would increase if the SCT pilot segment of the SmartAC program would be CAISO market integrated. The API would need to be expanded substantially to accommodate Sub Load Aggregation Point dispatch along with further expansions within DRMI to facilitate integration and registration of new SCT locations into existing SmartAC resources.

In the interest of bringing on MWs for May 2022, PG&E designated the SCT segment of the SmartAC program as a pilot so that it could be exempt from market integration. The IT development to support market integration would require more time and budget but could potentially be planned for 2023 if that is the desire of the CPUC.

Regarding the marketing, education and outreach efforts of the SCT program, PG&E would target hot climate zones for e-mail campaigns. SCT program recruitment is offered through three primary channels: in the manufacturer technology app, e-mails by the SCT manufacturer, and e-mails sent by the utility or DR provider. PG&E has the ability to and would limit e-mails to hot climate zones but cannot limit e-mails in the manufacturer app. It should be noted that limiting to hot climate zones can omit additional MWs which could be available during one in ten or twenty-year extreme weather scenarios.

E. Automated Demand Response

Q 7 Can PG&E respond to filed testimony advocating that third-party DR providers should be allowed to administer AutoDR incentives?[18]

A 7 PG&E believes the utilities are in the best position to administer AutoDR funds on behalf of all eligible customers. First, the CPUC has the most oversight in ensuring proper administration and ongoing reporting with the IOUs, which would be diffused if numerous entities are administering the funds. Second, distributed administration would most likely require additional effort by the CPUC.

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18 Joint Parties, p. 6, lines 18-21; OhmConnect, p. 10.

F. Response-related Dual Participation

Q 8 Multiple parties, including Southern California Edison Company (SCE)[19] and California Solar and Storage Association (CALSSA),[20] proposed that customers should be able to enroll in multiple DR programs and offerings. Does PG&E agree with this recommendation?

A 8 PG&E is neutral on these proposals as a general matter. PG&E believes it may be easier for customers to participate and engage in DR programs if compensation is available from more than one DR program from multiple DR providers (i.e., IOUs and Third-Party DR providers). However, a number of questions need to be answered in relation to load impact, baselines, and customer experience. Additionally, there needs to be sufficient transparency so that claims for providing resource adequacy by multiple DR providers do not end up being potentially duplicative, impacting contractual and program obligations, and accuracy of resource availability to the CAISO. As such, PG&E welcomes the opportunity to work with SCE, the CPUC, and other interested external stakeholders to evaluate the pros and cons of this dual participation proposal in SCE's Whole Home Savings Program Pilot. PG&E recommends that any relevant data points or lessons that point to a positive customer experience and that can produce more reliable DR performance should be explored. In particular, modifying the proposed pilot design for the ELRP Residential (A-5) as described in PG&E's Reliability Order Instituting Rulemaking Opening Testimony (Chapter 2) should be considered.

G. Witness

Q 9 Was this material prepared by you or under your supervision?

A 9 Yes, it was prepared by me, Jomo Thorne.

Q 10 Insofar as this material is factual in nature, do you believe it to be correct?

A 10 Yes, I do.

Q 11 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 11 Yes, it does.

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19 SCE, p. 36.

20 CALSSA, p. 4.

Q 12 Do you adopt this testimony as your sworn testimony in this proceeding?
A 12 Yes, I do.
Q 13 Does this conclude your reply testimony?
A 13 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

DEMAND RESPONSE AUCTION MECHANISM

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DEMAND RESPONSE AUCTION MECHANISM

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DEMAND RESPONSE AUCTION MECHANISM

A. Introduction

Pacific Gas and Electric Company (PG&E) provides rebuttal testimony in response to opening testimony filed by parties related to the Demand Response Auction Mechanism (DRAM) pilot expansion in 2022 and 2023.

B. Responses

Q 1 Do parties support expansion of the DRAM pilot in 2022 and 2023?

A 1 Yes, the Joint Parties[1] (California Efficiency + Demand Management Council, ecobee Inc., Leapfrog Power, Inc., and Oracle) and the Joint Demand Response (DR) Parties[2] (Cpower and Enel X North America, Inc.) recommend a partial-year supplemental auction for June-December 2022 and an expanded budget for the 2023 auction for an additional $13 million each year, for an additional approximately 150-175 megawatts of additional capacity per year, weighted for partial 2022 deliveries. California Energy Storage Alliance[3] (CESA) and Advanced Energy Economy[4] (AEE) also support supplemental DRAM auctions, but do not recommend a specific budget amount.

Q 2 Does PG&E support the expansion of the DRAM pilot as discussed by these parties?

A 2 No, as stated in PG&E's Opening Testimony,[5] PG&E strongly opposes such expansion given significant performance and reliability concerns with the DRAM pilot, which is a position supported by Southern California Edison Company[6] (SCE), Public Advocates Office at the California Public Utilities

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[1] Joint Parties Opening Testimony, p. 14, lines 15-29, to p. 15, lines 1-5.

[2] Joint DR Parties Opening Testimony, p. 13, lines 13-23, and p. 14, lines 20-27.

[3] CESA Opening Testimony, p. 55, lines 4-8.

[4] AEE Opening Testimony, p. 6, line 20, to p. 7, line 6.

[5] PG&E Opening Testimony, p. 6-1, line 18, to p. 6-3, line 18.

[6] SCE Opening Testimony, p. 69, line 19, to p. 72, line 2.

Commission[7] (Cal Advocates), and the California Large Energy Consumers Association[8] (CLECA). The parties supporting expansion of the DRAM pilot do not consider the types of performance and reliability concerns raised by PG&E, SCE, Cal Advocates, and CLECA.

Q 3 If the California Public Utilities Commission (CPUC or Commission) approves the expansion of the DRAM pilot, are the budget amounts proposed by the Joint Parties and the Joint DR Parties reasonable?

A 3 No, the specific amount of additional budget proposed was rejected in the 2018-2022 DR funding cycle in Decision 19-07-009, despite third-party proposals to increase the budget to these levels. There is no record to suggest that the issues that were raised in that proceeding and that currently exist today have been addressed, or that the amount of capacity that the Joint Parties propose is available could be realistically procured. As stated in the Cal Advocates' testimony, additional or expanded DRAM auctions are unlikely to procure significant quantities that can reduce demand at peak or net-peak hours.[9]

Q 4 If the Commission approves the expansion of the DRAM pilot, is the schedule proposed by the Joint Parties reasonable?

A 4 No, the schedule proposed by the Joint Parties is infeasible and does not allow for sufficient time to conduct the auction.[10]

First, the specific schedule the Joint Parties propose includes a Request for Offers (RFO) launch within seven days of a final decision. PG&E requires a minimum of 14 days to launch an RFO, assuming there are no modifications from proposed decision in this proceeding. If modifications are approved from the proposed to final decision in this proceeding, PG&E would require, at minimum, 21 days from the issuance of the final decision to update materials and launch the auction.

Second, the Joint Parties propose 13 days from when the cure period ends to notifying the shortlisted bidders, a process that requires a minimum

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[7] Cal Advocates Opening Testimony, p. 2-1, lines 10, to p. 2-3, line 17.

[8] CLECA Opening Testimony, p. 8, lines 4-13.

[9] Cal Advocates Opening Testimony, p. 2-4, line 1, to p. 2-5, line 2.

[10] Joint Parties Opening Testimony, p. 15, Table 1.

of a month. Additionally, the proposed timeline does not allow for evaluation of offer viability, internal evaluation and steering committee approvals, Procurement Review Group approvals, or Energy Division approvals for offers rejected or moved down in the bid stack due to offer viability.

Third, the Joint Parties propose 25 days from shortlist notifications to advice letter submittal, but 25 days is insufficient. Additional time is necessary for contracts to be executed, the required analysis to be developed, and the independent evaluator report to be written.

Therefore, the Joint Parties' schedule does not allow for sufficient time to administer the additional 2022 DRAM RFO and achieve a timeline that would allow for June 2022 deliveries. At minimum, an additional month is necessary to administer the RFO, suggesting deliveries would only be able to begin in July 2022, not June 2022. In addition, the DRAM contract requires California Public Utilities Commission (CPUC) approval and Qualifying Capacity (QC) assessment processes before Sellers can deliver their capacity, neither of which is included in the Joint Parties' schedule. If the Commission disagrees with the positions of PG&E, SCE, Cal Advocates, and CLECA and decides to order an additional 2022 DRAM RFO, PG&E requests that the schedule reflect the realities of administering the RFO and allow sufficient time between CPUC approval and disposition of the advice letter and delivery.

Q 5 If the Commission does not approve the expansion of the DRAM pilot, should the Commission adopt the Joint Parties' proposal?

A 5 No, the Commission should not adopt the Joint Parties' proposal to direct Investor-Owned Utilities to issue RFOs for bilateral DR Resource Adequacy (RA) contracts.[11] Such a proposal is duplicative of existing RA solicitations that are all-source and open to DR providers.

Q 6 Should proposals to extend the DRAM QC process to non-DRAM resources be adopted?

A 6 No, the Joint DR Parties' proposal to extend the DRAM QC process and supplant the load impact protocol processes[12] should be rejected, for the

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11 Joint Parties Opening Testimony, p. 18, lines 11-22.

12 Joint DR Parties Opening Testimony, p. 18, lines 25, to p. 19, line 26.

same key weaknesses PG&E identified in its reply testimony in Phase I of this proceeding.[13]

C. Witness

Q 7 Was this material prepared by you or under your supervision?

A 7 Yes, it was prepared by me, Neda Oreizy.

Q 8 Insofar as this material is factual in nature, do you believe it to be correct?

A 8 Yes, I do.

Q 9 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 9 Yes, it does.

Q 10 Do you adopt this testimony as your sworn testimony in this proceeding?

A 10 Yes, I do.

Q 11 Does this conclude your reply testimony?

A 11 Yes, it does.

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13 PG&E Reply Testimony, Phase I, p. 9-6, line 15, to p. 9-7, line 19.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

DISTRIBUTED ENERGY RESOURCES

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DISTRIBUTED ENERGY RESOURCES

A. Introduction

Pacific Gas and Electric Company (PG&E) provides reply testimony in response to opening testimony filed by parties related to Distributed Energy Resources (DER), including topics related to Electric Vehicles (EV).

B. Responses to DER (i.e., Vehicle-Grid Integration (VGI), Battery) Related Proposal

Q 1 Peninsula Clean Energy (PCE) asserts that:

> Participation in this program [Proposal 2: Residential EV Managed Charging through Vehicle-Grid Integration] would likely not be compatible with participation in other similar programs. The platform will interact with customers' vehicles via onboard telematics. Dual participation in a similar system will cause interference. However, PG&E is not currently planning a telematics-based VGI program, therefore there is no current risk of interference.[1]

Does PG&E agree with this statement?

A 1 No, PG&E does not agree with the statement that PG&E is not currently planning a telematics-based VGI program. Currently, PG&E utilizes vehicle telematics in its collaboration with Bavarian Motor Works (BMW) on the ChargeForward pilot.[2] Additionally, PG&E plans to leverage the learnings from ChargeForward and integrate vehicle telematics in the communication mechanisms included in PG&E's proposed V2X pilot programs (Advice Letter 6259-E).[3] PG&E has also proposed a managed charging pilot, funded through the Low Carbon Fuel Standard (LCFS) Revenue, that may use vehicle telematics to interact with customers' vehicles. The pilot was proposed in June 2021 as part of PG&E's LCFS Implementation Plan[4] and is currently awaiting California Public Utilities Commission (CPUC or

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1 PCE, Opening Testimony, p. 16.

2 PG&E and BMW Group Taking Next Step in Powering Electric Vehicles with Renewable Energy and Supporting Grid Reliability | PG&E (pge.com).

3 https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6259-E.pdf.

4 https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6226-E.pdf.

Commission) approval. If approved, PG&E plans to work with a third-party to implement the managed charging pilot in 2022.

Q 2 PCE offers two EV Vehicle-to-Building Pilot concepts (Residential V2B Pilot and Heavy-Duty Commercial V2B Pilot) as a way to provide services such as peak reduction. The pilot concepts assert that tasks would include a cost-benefit analysis, documentation of barriers encountered, overall feasibility, demonstrated load modification, and opportunities and challenges to scaling. PCE offers the budget for both concepts for a single site. Are the PCE concepts a duplication of PG&E proposals?

A 2 Yes. While PG&E believes EVs offer the potential to provide peak reduction during critical hours, PG&E has already submitted very similar V2X pilot program proposals to the CPUC pursuant to VGI Decision (D.) 20-12-029. PCE's pilot concepts would duplicate the work proposed by PG&E. Additionally, PG&E is proposing to conduct the same tasks at a fraction of the cost per site by requiring customer and original equipment manufacturer contribution, and allocating evaluation, measurement, and verification costs over a significantly larger number of sites (1,200+). Furthermore, as mandated by the D.20-12-029 Ordering Paragraph (OP) 14, PG&E:

> …jointly coordinate[d] with staff from the CPUC's Energy Division, the California Energy Commission, and other California load-serving entities (LSEs) to … ensure that the list [of priority needs for pilots] …avoid[s] overlap with the scope of the Electric Program Investment Charge program or *other programs* including programs administered by the California Energy Commission,…[5]

Therefore, PG&E believes PCE's pilot concepts are inconsistent with the spirit of the decision and prior efforts to avoid duplication.

Q 3 The Advanced Energy Economy (AEE) [6] and the California Energy Storage Alliance (CESA)[7] is supportive of aggregating both separately-metered and sub-metered EV charging to ensure that load reductions from EVs are maximized during grid events. Does PG&E agree with this recommendation?

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5 Decision Concerning Implementation of Senate Bill 676 and Vehicle-Grid Integration Strategies (D.20-12-029), OP 14, pp. 83-84.

6 AEE, Opening Testimony, p. 5, lines 17-19.

7 CESA, Opening Testimony, p. 53, lines 21-22.

A 3 No. PG&E does not agree with this recommendation. As witness Krefta pointed out in the COMMERCIAL ELECTRIC VEHICLE DAY-AHEAD HOURLY REAL TIME PRICING PILOT REBUTTAL TESTIMONY, submitted on May 5, 2021 in Application 20-10-011,[8] Electric Vehicle Supply Equipment (EVSE) submetering should not be allowed for either residential nor non-residential programs and pilots because the standards, data systems, and billing system changes have not yet been approved and authorized by the CPUC. This is being addressed in another case, Rulemaking (R.) 18-12-006.

The EV submetering and subtractive billing actually have been studied in an Electric Program Investment Charge (EPIC) report, which found at least three major categories of accuracy problems:[9]

> [i)] Time Shifting Issues, which occurred when the timing of a submeter's charging information did not match the timing of the logger or the whole-house bill, [ii] Recording Issues, which occurred when a submeter did not record an instance of charging, [iii)] Magnitude Issues, which occurred when the magnitude of the charging load recorded by the submeter did not match the magnitude of the charging load recorded by the logger.

Q 4 The California Solar and Storage Association (CALSSA) recommend that the aggregator's performance be measured and settled at the battery inverter in the Emergency Load Reduction Program (ELRP), rather than at the utility meter.[10] Does PG&E agree with this recommendation?

A 4 No. PG&E does not agree that the ELRP should be modified to allow performance to be measured and settled at the battery inverter level. PG&E's Demand Response Emerging Technology (DRET) Program is working with a battery manufacturer to evaluate the pros and cons of measuring demand response performance at the battery inverter level, and will release the results to the public when the study is completed in the first

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8 Ms. Krefta's testimony can be found in Exhibit (PG&E-4), pp. 3-10 to 3-15, https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2010011/3653/384940944.pdf.

9 Reference Name: EPIC 1.22 EV Submetering EPIC 1.22 Plug-In Electric Vehicle Submetering Pilot (PEVSP) at https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.22.pdf (as of July 20, 2021). 40 EPIC 1.22 EV Submetering EPIC 1.22 PEVSP, Executive Summary, p. ii.

10 CALSSA, Opening Testimony, p. 7, lines 24-25.

quarter of 2022. PG&E recommends CPUC to work with stakeholders through workshop to determine if ELRP should allow performance to be measured and settled at the DERs' meter level and the DRET study results can be used as a reference for the workshop. Issues raised by EVSE submeter, are also of concern for settling at the battery inverter level.

Q 5 PCE is proposing to fund the expansion of Net Peak Residential Storage Load Management and Residential EV Managed Charging through VGI utilizing ratepayer funds to pay for program costs. Does PG&E agree with this recommendation?

A 5 No. PCE has stated that an "expanded program within our service territory and a statewide program would require ratepayer funds for cost recovery of program costs."[11] PCE also stated in Residential EV Managed Charging through VGI that "PCE is requesting that this proposal cover startup and year 1 costs."[12] PCE is apparently suggesting that the investor-owned utility (IOU) ratepayers should pay for PCE proposed programs. Currently, PG&E does not have a source of funding for Customer Choice Aggregators (CCA) to run the types of programs proposed by PCE. Moreover, for the Commission to require such program costs to be paid for through IOU rates for bundled and unbundled customers, the Commission should have oversight of the CCA (or statewide) program and activities. This, in turn, may involve questions about the CPUC's regulatory authority over the PCE CCA program, such as the extent of CPUC control of such CCA programs, funding, rate design, or activities. In addition, even if the PCE pilot were successful, it may provide a localized benefit to PCE and its customers, but might not produce benefits for other LSEs' customers, such as PG&E or other CCAs. As a result, it is unclear if funding the proposed PCE pilot through the PPP rates that are paid by all bundled and CCA customers would be reasonable.

C. Witness

Q 6 Was this material prepared by you or under your supervision?

A 6 Yes, it was prepared by me, Albert Chiu.

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11 PCE, Opening Testimony, p. 12, lines 11-13.

12 Ibid, p. 17, lines 9-10.

Q 7 Insofar as this material is factual in nature, do you believe it to be correct?
A 7 Yes, I do.
Q 8 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 8 Yes, it does.
Q 9 Do you adopt this testimony as your sworn testimony in this proceeding?
A 9 Yes, I do.
Q 10 Does this conclude your reply testimony?
A 10 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

GAS CORE SERVICES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
GAS CORE SERVICES

A. Introduction

Pacific Gas and Electric Company (PG&E) provides reply testimony in response to opening testimony filed by Enchanted Rock, California Large Energy Consumers Association (CLECA), Sierra Club, Center for Energy Efficiency and Renewable Technologies (CEERT), and the Joint Parties (California Efficiency + Demand Management Council, ecobee Inc., Leapfrog Power, Inc., and Oracle).

B. Responses

Q 1 Enchanted Rock identifies risks to its proposal[1] that would require California Air Resource Board Diesel Generation Emission compliant generating facilities seeking to participate in Base Interruptible Program (BIP) for 2023 and beyond by conversion to an approved renewable fuel supply as the need for a ten-year floor price for BIP. Do other risks exist?

A 1 Yes. While PG&E cannot comment on the precise conversion incentives necessary, it can comment that under current gas rules and tariffs all generation over 500 kilowatts or with potential maximum usage of 250,000 therms annually must be served from PG&E's curtailable noncore G-EG tariff.

Q 2 How is this curtailable noncore G-EG tariff requirement for service a risk to conversion of current backup generation fueled by diesel or installation of new backup generation fueled by gas in displacement of diesel?

A 2 Many customers have approached PG&E seeking to be connected to PG&E's gas system to service their new backup generation, either to be aligned with the customers' environmental footprint goals or at the suggestion of the California Energy Commission after an original proposal for a diesel generator, only to be deterred by PG&E's inability to provide more reliable core transportation under our current gas rules and tariffs.

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[1] Enchanted Rock, Prepared Testimony of Joel Yu On Behalf of Enchanted Rock, LLC, p. 6, lines 4-13.

The inability to provide reliable core transport would be detrimental to the use of Renewable Natural Gas (RNG), as well as natural gas, rather than diesel.

Q 3 Do you have any additional comments on Enchanted Rock's proposal[2] for additional cleaner and clean-burning gas generation?

A 3 Yes. While PG&E cannot comment on the extent of diesel generation that could be converted to gas-fired generation, it can say that significant opportunities exist along its gas system, particularly its transmission system, for service to gas-fired back-up generation that could be viewed as economic for customers to consider, assuming core transportation reliability and cost. PG&E has over ten projects interested in such service should PG&E's proposal in this proceeding be adopted, with approximately 200 megawatts (MW) lined up for summer 2022 and more for Summer 2023 as discussed in PG&E's Phase 2 Opening Testimony.

Q 4 The Sierra Club, in addition to Enchanted Rock, cites the existence of over 8 gigawatts (GW) of back-up generation across just the three most populated areas of the state's 35 air quality districts, with 95 percent of this back-up generation fueled by diesel.[3] How does this capacity compare to the California Independent System Operator's (CAISO) typical available capacity?

A 4 According to the CAISO's website,[4] the available capacity at any moment in time is roughly in the range of 40,000 to 50,000 MW, or 40 to 50 GW. Therefore, based on these numbers and the amount of diesel-fired capacity across just three major air quality districts there is a substantial indication of back-up generation available for conversion to lower-emission generators fueled by natural gas.

Q 5 Does PG&E believe that conversion to gas-fired back-up generation is a practical opportunity?

A 5 Yes; as PG&E noted in its opening testimony, many customers, often among PG&E's most knowledgeable customers, are interested in gas-fired

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2 Ibid, p. 5, lines 2-10.

3 Sierra Club, Prepared Opening Testimony of Sahm White on Behalf of Sierra Club, p. 4, lines 6-9.

4 http://www.caiso.com/TodaysOutlook/Pages/index.html.

back-up generation, with the opportunity for use of RNG and other pipeline-quality lower emission fuel blends, instead of diesel because of the reduced emissions.

Q 6 Are other considerations also of interest in preventing the need for rotating outages and related impacts of an emergency reliability situation?

A 6 Yes. Conversion of the amount of capacity identified by Sierra Club would increase the ability of back-up generation to be available over several days of a heat wave for critical usage customers as described above, versus a short-term one-day five-hour event, which is important for the customers PG&E's proposal addresses. And the relative affordability of gas-fired back-up generation so that employers remain in California or provide new jobs in California is an additional factor. When these two additional factors are considered, allowing gas-fired back-up generation to be available as an economic choice that serves both local electric outage situations and state-wide CAISO reliability emergencies is a balanced approach as California continues on the path of emission reductions and a reliable grid.

Q 7 Does PG&E share the Sierra Club's concern about diesel pollution and greenhouse gas (GHG) emissions in the matter of grid reliability?[5]

A 7 Yes. The impact of the significant air pollution from a variety of emission sources when combined with wind patterns and the geography of PG&E's service territory are of concern to PG&E, for the people and economy in our area, along with the effects of climate change. PG&E supports the movement away from diesel when possible. Towards that goal, PG&E's proposed Core Transportation for Generation service as outlined in Chapter 8 of PG&E's September 1 opening testimony in Phase 2 is an affordable option to provide to customers for their needs while also providing additional cleaner-burning capacity when other reasonable measures have been exhausted in keeping the electricity flowing and the economy providing jobs across California. PG&E's proposal provides the opportunity to take some major, practical steps towards reducing emissions while keeping employers in California, and the opportunity for continued emission

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5 Sierra Club, Prepared Opening Testimony of Sahm White on Behalf of Sierra Club, p. 7, lines 13-18 and p. 8, lines 1-5.

reductions as RNG is made available for transportation via our pipeline system and as we support electrification and decarbonization of other current gas customers.

Q 8 Does CEERT's proposal to limit any additional gas capacity to short-term contracts create a roadblock to the transition from diesel back-up generation to gas-fired backup generation?[6]

A 8 Yes, to use cleaner-burning gas, customers may need to invest in new gas generators as well as gas interconnection costs. These can be significant investments to be recovered over a period that is not a matter of a year or two. Therefore, reducing GHG emissions by using gas would not be financially feasible without long-term reliability. Additionally, CEERT's proposal ignores the medium and long-term potential for gas-fired backup generation, once installed, to have the option for these customers to procure RNG and further reduce GHG emissions in the state.

Q 9 Does gas-fired generation have a role as a necessary resource beyond the next two summers and through the rest of the decade as indicated in CLECA's testimony?[7]

A 9 Yes, PG&E agrees that the emission consequences of reliance on gas-fired generation would be significantly lower than reliance on diesel back-up generation and that gas-fired generation availability continues to have an important role for the foreseeable future to support the grid. Furthermore, to the extent that customers are willing to pay for installation of gas-fired back-up generation, this offers society the additional benefit of the generation not only being used for the CAISO grid as necessary but then also being available for the customer's needs when outages occur. Thus, back-up gas-fired generation can exist under very low load factor usage for the purpose of protecting the reliable electric power supply for the customer.

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6 CEERT, Opening Phase 2 Prepared Testimony of The CEERT, p. 2, lines 3-7.

7 CLECA, Testimony of Catherine Yap And Paul Nelson On Behalf of the CLECA, p. 7, line 6-12, footnotes 10 and 11.

Q 10 Do you agree with the Joint Parties[8] that "[t]he Commission should allow BIP participants with prohibited backup generators ("BUGs") to participate in all DR programs on the condition that they are powered with RPS-eligible fuels"?

A 10 PG&E has addressed the question of multiple participation in Demand Response (DR) programs in Chapter 4 section F, Q/A 8. The considerations described in that part of PG&E's rebuttal testimony apply to BIP participants also participating in other DR programs. The use of Renewable Portfolio Standard fuels does not change those concerns.

C. Witness

Q 11 Was this material prepared by you or under your supervision?

A 11 Yes, it was prepared by me, Katy Lamb.

Q 12 Insofar as this material is factual in nature, do you believe it to be correct?

A 12 Yes, I do.

Q 13 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 13 Yes, it does.

Q 14 Do you adopt this testimony as your sworn testimony in this proceeding?

A 14 Yes, I do.

Q 15 Does this conclude your reply testimony?

A 15 Yes, it does.

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8 Joint Parties, Opening Phase 2 Prepared Testimony of the Joint Parties (California Efficiency + Demand Management Council, ecobee Inc., Leapfrog Power, Inc., and Oracle), p. 30, lines 13-22.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

REBUTTAL TO VALLEY CLEAN ENERGY AGRICULTURAL REAL TIME PRICING PROPOSAL

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REBUTTAL TO VALLEY CLEAN ENERGY AGRICULTURAL REAL TIME PRICING PROPOSAL

A. Introduction

Pacific Gas and Electric Company (PG&E) provides rebuttal testimony in response to opening testimony filed by Valley Clean Energy (VCE) proposing to implement a Real Time Pricing (RTP) Program for its Community Choice Aggregation (CCA) agricultural customers in its service area.

B. Responses

Q 1 VCE recommends that the current pricing faced by CCA customers who would participate in VCE's proposed Agricultural RTP program be replaced by a single hourly total energy only rate that encompasses all customer, demand, energy, and other pricing elements such as Peak Day Pricing (PDP) and Demand Response (DR).[1] Does PG&E agree?

A 1 No. PG&E customers who receive generation service from a CCA entity must individually pay to PG&E all non-generation rate components applicable under PG&E's California Public Utilities Commission (CPUC or Commission) approved tariffs. This includes component distribution rates, transmission rates established by the Federal Energy Regulatory Commission (FERC), and several non-bypassable charge (NBC) rate components. Simply put, VCE has no jurisdiction over any of PG&E's non-generation rate components. VCE's rate making authority is strictly limited only to its component generation rates, over which the Commission has no rate making authority.[2] VCE has no authority to dictate the incumbent utility delivery company's non-generation portions of total electric rates to serve its CCA purposes.

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1 VCE, Opening Prepared Testimony of Gordon Samuel On Behalf of Valley Clean Energy (VCE Opening Testimony), p.7, lines 14-23.

2 C.f., Decision (D.) 05-012-041, p. 9, "For example, the statute [AB 117] does not require the Commission to set CCA rates or regulate the quality of its services."

Q 2 But VCE indicates that it will make the Investor-Owned Utility (IOU) whole for the non-generation rates applicable under the IOU's Otherwise Applicable Tariff (OAT).[3] Would this resolve PG&E's concerns?

A 2 No. VCE proposes an overly complicated memorandum account to track the difference between the non-generation revenues paid under the IOU's OAT and the actual non-generation rate revenues paid by the participating Agricultural RTP pilot program customer under VCE's total all-in single hourly energy price. Tracking such differences for each individual participating VCE Agricultural RTP customer would require changing ratemaking and rate design for PG&E's non-generation revenues, then making complex modifications to PG&E's systems for billing customers and recording their payments, as well as complicated memorandum account structures segregated by each of the applicable distribution, FERC transmission, and non-bypassable rate components.[4] VCE offers no funding solution to support the complex component revenue tracking and billing system measures that would be necessary to implement VCE's proposal. Assuming hypothetically that differences could even be tracked in the accounts, it is also not clear who would be responsible for paying them.[5] Nor can it be determined if VCE's proposal would cause cost shifting between its CCA customers and bundled customers.[6] Therefore, any

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3 VCE Opening Testimony, p. 12, lines 22-27.

4 Under the current billing structure, PG&E would continue to bill the customer for the non-generation components. Therefore, it is unclear how VCE's proposal would work, as the proposed memorandum account would need to segregate, compare, and reconcile each applicable sub-functionalized rate component. Moreover, a memorandum account implies the need for future reasonableness reviews, which would be inappropriate in this context, as the OAT non-generation sub-functionalized revenues the customer is to pay PG&E are already authorized by the CPUC in approved tariffs. In that context, a two-way balancing account with no reasonableness review would be necessary, not a memorandum account.

5 For example, PPP rates would not be time differentiated under settlements submitted in PG&E's 2020 GRC Phase II, Application (A.) 19-11-019, and currently awaiting a Proposed Decision.

6 C.f. Public Utilities Code Section 366.2 (a) (4), "The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."

amounts accrued in the accounts should be recovered from VCE and its agricultural customers.

Q 3 VCE seeks funding to cover the costs of its proposed Agricultural RTP pilot program from PG&E's Public Purpose Program (PPP) charges, to make bundled IOU customers and VCE's CCA customer whole.[7] Does PG&E agree that such funding would be appropriate?

A 3 No. PPP charges and authorized total PPP revenues are already set by the CPUC to recover the costs related to a variety of public purpose programs, such as California Alternate Rates for Energy (CARE) discounts for qualifying low-income customers, low-income energy efficiency programs, tree mortality programs, and other programs. These PPP funds are fully allocated to achieve the authorized cost recovery for this established pre-existing CPUC portfolio of approved or adopted PPP programs and elements.

Consequently, there are no excess PPP funds available for new programs such as the Agricultural RTP program proposed by VCE, until the CPUC authorizes additional PPP budget for VCE's new program.[8] Further, and more fundamentally, CCAs are generally required to fund their own administrative costs, and have no authority to force bundled customers in general, or the customers of other CCA entities, to fund the specific administrative costs of one specific CCA such as VCE. Moreover, for the CPUC to approve PPP funding of such a VCE Agricultural RTP pilot program, the CPUC would need to be able to exercise oversight over such CCA programs and activities as VCE's proposed Agricultural RTP pilot program. This, in turn, would involve questions about the CPUC's regulatory authority over the VCE CCA program, funding, rate design etc., which may be subject to debate. In addition, even if the VCE Agricultural RTP program were successful, it may provide a localized benefit to VCE and its customers, but may not benefit PG&E's bundled customers, or customers of other CCAs. As a result, funding the proposed VCE Agricultural RTP pilot

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[7] VCE Opening Testimony, p.13, lines 3 to 5.

[8] PG&E also wishes to point out that an Agricultural RTP pilot program would be ineligible for Automated Demand Response funding under the CPUC's related rules.

through the PPP rates that are paid by all bundled and CCA customers may not be reasonable.

Q 4 VCE claims that agricultural irrigation is a prime candidate for inclusion in such an Agricultural RTP pilot program.[9] Does PG&E agree?

A 4 No. PG&E's experience with DR programs is that participation by and the potential for load relief available in the Agricultural sector generally lags significantly behind that of commercial and industrial customers.[10] Further, the Agricultural Energy Consumers Association (AECA), a major intervenor which often represents the interests of agricultural customers before the CPUC, has generally indicated that DR programs do not provide sufficiently high incentives to motivate substantial participation by customers in the Agricultural sector. AECA has further indicated that agricultural customers generally need advance notice of several days or a week ahead in order to respond to hourly prices, and is unable to respond to day-ahead or day-of hourly prices, given the strictures of surface water availability and the sometimes rigid delivery schedules administered by water agencies to furnish agricultural customers with water for crop irrigation purposes.[11] VCE has provided no evidentiary basis that this operational and logistical concern regarding the lack of flexibility often endemic to irrigation scheduling could be ameliorated by either the agricultural customers or the serving water agencies located in the Davis, Woodland, Winters, and unincorporated portions of Yolo County that comprise VCE's CCA service territory.

Finally, it should be noted that PG&E's proposed RTP program currently under consideration in Track 2 of PG&E's pending 2020 GRC Phase II

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9 VCE Opening testimony, p. 5, line 14, to p. 6, line 16.

10 See Tables 13-16 and 13-17 in PG&E's 2020 General Rate Case (GRC) Phase II Rebuttal Testimony, Exhibit (PG&E-7), February 26, 2021, Chapter 13, pp. 13-69 to 13-72, in pending A.19-11-019.

11 See AECA, Opening Testimony, in PG&E's 2020 GRC Phase II proceeding, Public Version, November 20, 2020, pp. 49-51. Even though VCE indicates (at the top of page 10) that week-ahead RTP prices can be locked in, (despite its statement about using day-ahead CAISO prices), it is worth noting that prices set so far in advance may entirely miss the mark as to when the constrained grid high-cost procurement hours actually occur, and may therefore provide less value than day-of or day-ahead RTP pricing programs.

proceeding on marginal cost, revenue allocation, and rate design, is directed only toward larger commercial and industrial customers. However, AECA's proposal in PG&E's 2020 GRC Phase II proceeding for an agricultural rate that can change each day and hour based on triggers known up to a week in advance, and using pre-established price curves, such as Southern California Edison Company's Schedules Time-of-Use (TOU)-PA-2-RTP and TOU-PA-3-RTP and rates, is also in PG&E's 2020 GRC Phase II Track 2 RTP phase, set for hearings in late January 2022. The fact that RTP for agricultural customers is being considered in PG&E's RTP case, is an additional reason that VCE's RTP proposal in this rulemaking should be dismissed outright.

Q 5 VCE indicates that its proposed all-in-one RTP hourly energy total rate design is very simple compared to the overall IOU customer, demand and energy non-generation rates faced by IOU customers. Do you agree?

A 5 No. First, as a preliminary matter, what VCE is proposing is highly inappropriate from a cost of service perspective. VCE is proposing to place the entire overall retail electric rate on a TOU and/or hourly basis. However, only those costs incurred on a TOU basis are appropriate for recovery on a TOU basis. For the agricultural class, only approximately 40 percent of the full retail class average rate is authorized by the CPUC to be collected on a TOU basis. The remaining 60 percent consists of rate elements that apply on a totally flat, non-TOU basis.[12] Therefore, VCE's proposal to place 100 percent of the total retail rate on an hourly basis that is even more granular than bucketed TOU rates is not cost-based, and is highly inappropriate.

Further, RTP hourly energy prices are generally confined only to the generation component of electric rates. PG&E is not aware of hourly RTP prices that include distribution or transmission components that themselves

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12 More specifically, generation comprises approximately 41 percent of agricultural total bundled revenues, with distribution at 41 percent, FERC Transmission Owner at 9 percent, PPP at 6 percent, and other NBC's at 3 percent, at current August 1, 2021 effective electric rates. However, approximately 34 percent of generation is non-TOU based Power Charge Indifference Adjustment (PCIA) rates, and approximately 71 percent of agricultural distribution revenues are collected on the basis of non-coincident anytime non-TOU based distribution demand charges or distribution customer charges.

change hourly, being offered by other utilities or service providers anywhere in the United States.[13] PG&E cannot agree to what the appropriate hourly distribution or transmission price signals and design methodology should be for these, as distribution, transmission, and generation capacity infrastructure may all differ regarding their pattern of constrained or critical system reliability issues on local, bulk, or system bases.

Although it is conceptually possible that hourly RTP's could be used for distribution and transmission as well as generation,[14] PG&E is not aware of any proposal pending before the CPUC to account for the different hourly loads and associated pricing signals that would be respectively appropriate for distribution, transmission, or generation facilities that almost certainly will peak at different times on a local, regional, or systemwide basis. Moreover, such information is not available on a day-ahead, hourly basis at the granularity suggested by VCE's proposal.

Only the generation component of rates, and proper design of an appropriate hourly RTP generation price signal encompassing energy, generation capacity, and revenue neutrality,[15] is currently being considered

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13 See A.19-11-019, Exhibit (PG&E-RTP-1), Chapter 1, Appendix A, Attachment A for a survey of RTP structures at other utilities.

14 FERC jurisdictional rate design has long rejected marginal cost-based ratemaking principles employed in California, instead embracing embedded cost 12-coincident peak ratemaking for component Transmission Owner and component Reliability Services that utilize non-coincident anytime demand charges per kilowatt (kW) that are not TOU based, or energy charges per kilowatt-hour (kWh) that are flat and also not TOU based. The Solar Energy Industries Association has for the past decade sought to compel the major electric IOU's in California to propose TOU based ratemaking at FERC, without success. The CPUC cannot now simply hand over the FERC component of rates to VCE to do with as it pleases, in contravention of FERC authority over how transmission price signals are sent to retail electric customers. Similarly, the CPUC has adopted non-TOU based PCIA rates that are also non-TOU based, as they represent the cost of long-term contractual above market generation sources procured on behalf of customers who subsequently departed IOU service for DA or CCA service, as inter temporal developments in generation commodity costs across the years or decades occur for non-TOU based reasons.

15 Development of the generation capacity price for RTP in A.20-10-011 and A.19-11-019 will be based on the annual marginal generation capacity cost (MGCC) approved by the Commission in the 2020 GRC II case, A.19-11-019, and in effect without change until the next GRC Phase II decision. The MGCC will then be distributed to those hours identified under a yet-to-be-determined methodology. RTP proposals should be revenue neutral to the otherwise applicable TOU generation demand and energy charges to prevent revenue shortfalls or over-collections.

for hourly RTP treatment in either of PG&E's two current pending RTP dockets.[16] Furthermore, all NBC's are not expressed on a TOU basis, let alone an hourly RTP basis. Thus, VCE's proposal to place the entire overall total electric rate on an hourly price signal, including one without fixed customer charges, or per kW demand charges, is highly inappropriate.

Second, PG&E does not agree that VCE's proposed rate design is simple. VCE's proposed 6-step hourly RTP rate design construct[17] is very complicated, much more so than traditional IOU rate design elements limited to relatively simple customer, demand, and energy charge elements or less complex TOU designs.[18] How VCE would even acquire the supporting data necessary to accomplish VCE's specified Step 2, distribution and circuit loads, and VCE's Step 6, all fixed and variable distribution costs, as part of its proposed hourly RTP pricing methodology, appears extremely unclear and questionable to PG&E. In addition, Step 2, as well as Step 3, the hourly and total net load placed by VCE or PG&E on the wholesale grid, are not known until after the fact, and therefore are not implementable.[19] Further, PG&E emphasizes that it is wholly inappropriate to roll fixed monthly customer charge costs, or fixed infrastructure capacity or demand charge costs, into an energy-only volumetric rate per kWh, even on a TOU bucketed basis, let alone on an hourly basis. In short, VCE's proposed rate would violate a number of sound rate design concepts and practices.

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16 RTP is being considered in both PG&E's October 23, 2020 "Application of Pacific Gas and Electric Company For Approval of Its Proposal For A Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot" (A.20-10-011, the "DAHRTP-CEV" proceeding), and in the testimony served November 20, 2020 in PG&E's 2020 General Rate Case Phase II (GRC II) proceeding (A.19-11-019).

17 VCE Opening Testimony, p. 9, lines 6 to 17.

18 VCE opening Testimony, p. 7, line 14-21.

19 In addition, VCE's proposed RTP rate design appears to include a "Subscription Part" defined in footnote 4 on page 7 that is based upon a charge or credit tied to the extent to which actual loads vary from a fixed load profile set in advance. This not only seems overly complicated, but may introduce considerable risk and uncertainty into the magnitude of such charges. Agricultural customers do not like uncertainty, or frameworks which may inhibit their operational flexibility to irrigate in a manner most beneficial to the health of their crops or other products.

Q 6 VCE proposed that Auto DR Program funding is available to customers participating in the Agricultural RTP pilot rate.[20] Do you agree?

A 6 No. PG&E's Auto DR Program is only available to eligible customers enrolled in the Capacity Bidding Program, PDP Program, SmartRate™, and Demand Response Auction Mechanism. This list of eligible DR Program was approved by the CPUC and any modifications would require CPUC approval.

C. Conclusion

Q 7 Can you please summarize your recommendations regarding the Agricultural RTP pilot rate proposed by VCE?

A 7 Although PG&E appreciates the ambitious goals envisioned by VCE to work with third-party vendors Polaris Energy Services and TeMix[21] to develop an Agricultural RTP demonstration project, PG&E believes VCE's proposal is conceptually flawed by seeking to extend its rate design beyond its jurisdictional generation component or CCA boundaries, and to seek IOU funding to implement an overly complex RTP rate design defined in ways that violate standard rate design and cost recovery methods. A cursory review of VCE's testimony indicates tremendous implementation difficulties, and more careful consideration likely will reveal more challenges. On the other hand, if VCE were to confine its proposal simply to the design of its own generation rates, and to self-fund its proposed demonstration project, PG&E may welcome the information such an Agricultural RTP pilot program may provide, if VCE were willing to share the data with PG&E.

D. Witness

Q 8 Was this material prepared by you or under your supervision?

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20 VCE Opening Testimony, p. 12, lines 28-30.

21 PG&E itself has a long history of partnering and working cooperatively with UC Davis, Lawrence Berkeley National Laboratory, and other leading agricultural research colleges, universities, and institutions conducting leading edge studies in agricultural energy efficiency, motor and pump efficiency and testing, variable frequency drives, irrigation systems and techniques, crop and soil enhancements, energy management and load control systems that respond to and optimize operations under TOU price signals, and any variety of other agricultural water energy nexus issues. This marketplace consists of many manufacturers and vendors, is highly competitive, ever evolving, and would remain vibrant and progressive even without the Agricultural RTP project proposed by VCE.

A 8 Yes, it was prepared by me, Keith B. Coyne.
Q 9 Insofar as this material is factual in nature, do you believe it to be correct?
A 9 Yes, I do.
Q 10 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A 10 Yes, it does.
Q 11 Do you adopt this testimony as your sworn testimony in this proceeding?
A 11 Yes, I do.
Q 12 Does this conclude your reply testimony?
A 12 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

SUPPLY-SIDE PROCUREMENT FOR SUMMER 2022/2023

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A. Introduction

Q 1 What is the purpose of this chapter?

A 1 The purpose of this chapter is to reply to proposals submitted in opening testimony by the California Large Energy Consumers Association (CLECA), Calpine Corporation (Calpine), Wärtsilä North America, Inc. (Wärtsilä), Independent Energy Producers Association (IEPA), Western Power Trading Forum (WPTF), and LS Power Development (LS Power). In addition, this chapter replies to parties' comments in opening testimony on Energy Division Staff's Concept Paper (Concept Paper) on supply-side solutions. The following Pacific Gas and Electric Company (PG&E) reply testimony supports the use of an expedited procurement approval process for the investor-owned utilities (IOU) to address reliability concerns for the summers of 2022 and 2023.

B. Reply to Proposals Regarding Opportunities to Bring New Battery and Generation Resources Online by the Summers of 2022 and 2023

Q 2 In response to the Concept Paper, a number of parties, including Calpine, LS Power, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and the California Community Choice Association (CalCCA), did not support establishing a penalty structure for the procurement orders adopted in Decision (D.) 19-11-016.[1] Do you agree with these parties?

A 2 PG&E agrees with these parties and recommends that the California Public Utilities Commission (Commission) not adopt a penalty structure for the procurement orders adopted in D.19-11-016. PG&E concurs with CalCCA that adopting a penalty structure related to the 2019 Integrated Resource

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1 Testimony of Matthew Barmack on Behalf of Calpine Corporation, p. 2; Prepared Phase 2 Opening Testimony of Sandeep Arora on Behalf of LS Power Development, LLC, p. 7; Direct Testimony of Southern California Edison Company – Phase 2, p. 76; Direct Testimony of Lauren Carr, Fred Taylor-Hochberg, Marie Y. Fontenot on Behalf of California Community Choice Association, pp. 8-9.

Planning (IRP) procurement order of 3,300 megawatts (MW) at this stage in the process, especially for already-executed contracts or contracts involving projects experiencing delays outside of the procuring entity's control, could have unintended consequences. CalCCA appropriately testifies that a new penalty structure could result in necessary amendments to already-executed contracts to account for the new penalty structure and may leave the procuring entity with little to no options to implement the new generation in a manner that is compliant with the new penalty mechanism.[2] Similar to PG&E, SCE highlighted that there is no evidence that a new penalty structure at this stage in the process is necessary to incentivize procurement toward the D.19-11-016 procurement requirements in light of Energy Division Staff's recently-released update on compliance with D.19-11-016.[3] Notably, procuring entities are collectively over procured for all three tranches by 329 MWs, 375 MWs, and 668 MWs, respectively, on a cumulative basis.[4] As a result, PG&E believes that a new penalty structure will not result in any material differences in bringing new resources online or change the timeline of the procurement requirements that have already been achieved based on Energy Division Staff's assessment.

Q 3 While WPTF did not explicitly support a penalty structure for the D.19-11-016 procurement requirements, WPTF suggested that the IOUs' shareholders should be responsible for the costs should the Commission impose fines on the IOUs for not meeting D.19-11-016 procurement requirements under Public Utilities Code § 2017 et seq. Do you agree with WPTF?

A 3 No, PG&E does not agree with WPTF. PG&E disagrees with the premise underlying WPTF's opening testimony regarding how non-IOU load serving entities (LSE) recover their costs associated with the procurement of generation resources. WPTF argues that when a non-IOU LSE is assessed

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2 Direct Testimony of Lauren Carr, Fred Taylor-Hochberg, Marie Y. Fontenot on Behalf of California Community Choice Association, pp. 8-9.

3 Direct Testimony of Southern California Edison Company – Phase 2, p. 77.

4 See the Commission's Status Update on Procurement in Compliance with D.19-11-016 at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf.

fines, the corresponding costs are borne by the LSE's owners (e.g., shareholders).[5] Thus, to provide for equity across all LSEs, WPTF proposes that the Commission should also ensure that any fines assessed against the IOUs are likewise paid by the IOUs' shareholders rather than its customers. It is PG&E's understanding, however, that the recovery of costs associated with procurement (or lack thereof) is a business-specific decision. An energy service provider or other non-IOU LSE has sole discretion to recover costs from its customers or not. Requiring IOUs to recover any costs incurred due to failure to procure from their owners (e.g., shareholders) rather than customers on the basis that a few LSEs may have made a discretionary business decision to do so is without merit, and any such proposal should be rejected.

Q 4 In lieu of a new penalty structure and increasing the RA penalty prices, California Energy Storage Alliance (CESA), LS Power, SDG&E, and SCE recommended the use of an expedited procurement approval process for the IOUs to increase supply to address the reliability concerns for the summers of 2022 and 2023. Does PG&E agree with this recommendation?

A 4 Yes. PG&E agrees with CESA, LS Power, and SDG&E that bringing new resources online by the summers of 2022 and 2023 will be challenging. Acknowledging this challenge facing the Commission, PG&E concurs with CESA, LS Power, SDG&E, and SCE on the use of an expedited procurement approval process for the IOUs.[6] PG&E further recommends that this expedited approval process apply to the central procurement entities (CPE) designated in D.20-06-002.

In its review of the incremental supply filings submitted by the IOUs to the Commission, PG&E found that 776 MW (June), 1,156 MW (July), 664 MW (August), and 1,026 MW (September) of procurement were

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5 Western Power Trading Forum Phase 2 Opening Testimony, p. 3.

6 Prepared Phase 2 Opening Testimony of Sandeep Arora on Behalf of LS Power Development, LLC, pp. 2-4; Direct Testimony of Southern California Edison Company – Phase 2, p. 59; Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance, p. 16.

completed.[7] PG&E continues to support the procurement parameters that have been adopted by the Commission in D.21-02-028 and D.21-03-056, including the use of a Tier 1 advice letter (AL) process for resources that are not IOU owned, a Tier 2 AL process for utility owned resources, and broad cost recovery through the existing cost allocation mechanism. Thus far, these procurement parameters have proven successful as the IOUs have undertaken significant procurement efforts to meet the Commission-established procurement targets.

In its opening testimony, SDG&E noted that the Concept Paper appears to contemplate modifications to these procurement parameters by: (1) limiting new energy storage to projects that can come online by the summer of 2022 and (2) modifying the approval process through the use of Tier 3 ALs for utility-owned projects. The continued use of a Tier 2 AL process for utility owned resources, as adopted in D.21-02-028, could be effectively utilized to facilitate a variety of procurement types that are consistent with and facilitate state policy goals, including those identified in this proceeding and the IRP proceeding. PG&E reiterates its recommendation that the Commission take prudent steps to ensure this procurement, especially procurement types that effectively serve the net peak window, like pumped storage and storage at utility owned sites, and can come online as soon as possible.

In that same vein, PG&E's proposed interim modifications to the CPE framework will streamline the procurement process given the accelerated timelines before the Commission. The CPE was established to provide "cost efficiency, market certainty, reliability, administrative efficiency, and customer protection" when procuring to meet local area reliability needs. PG&E's proposal would only establish the same parameters that are provided to SDG&E—another IOU ordered to procure on behalf of its distribution service territory customers but without the same barriers to local RA procurement that exists for PG&E acting in the role of the CPE. PG&E believes that this limited scope will meet the Commission's objectives of this

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[7] See Excess Resources Report at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

proceeding and the RA proceeding adopting the CPE framework and accordingly urges the Commission to adopt PG&E's proposal for interim modifications to the CPE framework as set forth in its opening testimony.

Q 5 Does PG&E support explicit procurement requirements (e.g., resource procurement carve-outs) as suggested by Wärtsilä, IEPA, Calpine and CLECA?

A 5 In response to the Concept Paper, a number of parties proposed highly prescriptive procurement requirements or directives. While these requirements may serve to ensure procurement of certain parties' preferred resources, PG&E does not believe they are in the interests of customers, system reliability, or California's climate goals. In particular, PG&E is concerned that these types of procurement requirements may serve to compromise cost-effectiveness, potentially resulting in the procurement of unnecessarily expensive contracts. To this point, CLECA aptly pointed out that poorly considered procurement solutions have the potential to repeat mistakes made in response to the 2000-2001 energy crisis.[8] PG&E agrees with this assessment. Solutions ordered in this proceeding should result in procurement of cost competitive resources that are available during the net peak window and should address time frames appropriate with the objectives of this proceeding.

PG&E notes that multiple proposals articulated in opening testimony are inconsistent with these objectives. For example, IEPA suggests the Commission order the IOUs to sign three to five year contracts with "any facility in the CAISO control area whose existing contracts expire before the end of the summer 2022 or summer 2023 seasons, or that currently have a Reliability Must Run designation."[9] This proposal is overly broad and risks exacerbating already high customer costs by conferring significant supplier market power. Moreover, it suggests the IOUs execute mandatory procurement with an unknown quantity of resources that are likely older, less efficient, and greenhouse-gas (GHG) emitting. This proposal is not

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8 Testimony of Catherine Yap and Paul Nelson on Behalf of the California Large Energy Consumers Association, p. 2.

9 Prepared Testimony of Scott Murtishaw on Summer 2022 and 2023 Reliability Enhancements on Behalf of the IEPA, p. 8.

sufficiently informed by the present need, may jeopardize the state's climate goals, would significantly increase customer costs, and could potentially leave the IOUs stranded with any GHG-emitting attributes.

Similarly, Wärtsilä and CLECA proposed significant procurement of natural gas resources that may serve to jeopardize the goals of this proceeding. Wärtsilä proposes significant expedited procurement of their own reciprocating internal combustion engines, which are currently capable of functioning using 25 percent hydrogen fuel.[10] PG&E also believes this proposal is unnecessarily prescriptive, would jeopardize California's emissions goals, and relies on a single, unproven emitting technology.

Finally, multiple parties, including Calpine and CLECA, proposed addressing capacity shortfalls through retrofits to existing thermal generating resources. While PG&E believes these upgrades may have the potential to provide incremental reliability benefits and has worked to execute upgrades at some of its own facilities, an explicit mandate would be unwise for many of the same reasons outlined above. An explicit mandate would provide those thermal resources with market power, raising prices for contracts that may not be prudent, and may unnecessarily extend the life of GHG-emitting resources.

C. Witness

Q 6 Was this material prepared by you or under your supervision?

A 6 Yes, it was prepared by me, Gillian Clegg.

Q 7 Insofar as this material is factual in nature, do you believe it to be correct?

A 7 Yes, I do.

Q 8 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 8 Yes, it does.

Q 9 Do you adopt this testimony as your sworn testimony in this proceeding?

A 9 Yes, I do.

Q 10 Does this conclude your reply testimony?

A 10 Yes, it does.

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10 Opening Testimony and Proposals of Dr. Karl Meeusen on Behalf of Wärtsilä, p. 8.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KEITH B. COYNE

Q 1 Please state your name and business address.

A 1 My name is Keith B. Coyne, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Rate Analyst in the Electric Rates section of the Rates Department. My responsibilities include developing and evaluating electric rates for the agricultural and small, medium, and large commercial and industrial customer classes.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Mathematics and Economics from Occidental College in 1978, and a Master's degree in Business Administration from University of California, Los Angeles in 1980.

I joined PG&E in 1980 as an Economic Analyst in the Economics and Statistics Department. I transferred to the Rates Department in 1984 and served as the Residential Time-of-Use (TOU) Project Manager between 1984 and 1988. Between 1989 and 1994, I was responsible for residential electric rate design, sponsoring testimony in PG&E's 1991 and 1992 Electric Rate Design Window (RDW) and 1993 General Rate Case (GRC) Phase II proceedings.

In 1994, I assumed my present responsibilities for commercial and industrial rate design, sponsoring testimony in PG&E's 1995 and 1997 Electric RDW, and 1996 and 1999 GRC Phase II proceedings. In 1999, I assumed my present responsibilities for agricultural rate design, sponsoring testimony in the 1999 GRC Phase II. In 2001, I served as a witness in the Rate Design phase of the Rate Stabilization Plan proceeding addressing the three-cent generation surcharges.

In 2002 and 2003, I sponsored electric revenue estimation and rate design testimony in PG&E's 2003 GRC Phase I. I also sponsored agricultural, commercial, and industrial rate design testimony in PG&E's 2003, 2007, 2011, 2014, and 2017 GRC Phase II, as well as agricultural rate design in PG&E's 2020 GRC Phase II. I also sponsored electric rate design testimony in the 2006 and 2007 Forecast Energy Resource Recovery Account cases, and agricultural rate design testimony for Schedule AG-ICE in the 2004 proceeding for rate and line extension incentives for conversion of stationary agricultural irrigation internal combustion equipment to electric service.

In addition, I also sponsored mobile home park baseline diversity benefit testimony in the 2007, 2011, 2014, 2017, and 2020 GRC Phase II proceedings, as well as the 2018 Gas Cost Allocation Proceeding. In 2015, I sponsored rate design testimony for the new residential Schedule E-TOU rates with a shorter four-month summer season, and later 3 p.m. to 8 p.m. or 4 p.m. to 9 p.m. on peak hours. In 2019, I sponsored follow-up agricultural rate design testimony in PG&E's 2019 RDW, for certain modifications to the agricultural electric rates adopted in PG&E's 2017 GRC Phase II proceeding.

Finally, I also served as regulatory case manager for PG&E's 2010 RDW Residential Peak-Time Rebate Proposal, and case-managed a number of prior GRC Phase II and mobile home park proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Emergency Reliability Order Instituting Rulemaking Proceeding:

- Chapter 8, "Rebuttal to Valley Clean Energy Agricultural Real Time Pricing Proposal."

Q 5 Was this material prepared by you or under your supervision?

A 5 Yes, it was.

Q 6 Insofar as this material is factual in nature, do you believe it to be correct?

A 6 Yes, I do.

Q 7 Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A 7 Yes, it does.

Q 8 Do you adopt this testimony as your sworn testimony in this proceeding?

A 8 Yes, I do.

Q 9 Does this conclude your statement of qualifications?

A 9 Yes, it does.