**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas & Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M.)	Application 19-11-019 (filed November 22, 2019)

RTP REBUTTAL TESTIMONY OF PAUL L. CHERNICK AND JOHN D. WILSON ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

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Attachment 3	*Joint Exhibit Presenting Stipulation between SBUA, Enel X and PG&E on Time-Differentiation of the Revenue Neutral Adders for the DAHRTP-CEV Pilot Rate (A.20-10-011, Exhibit PG&E-21, June 1, 2021)*
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I. Introduction

Q: Are you the same Paul Chernick and John D. Wilson who filed Direct, Rebuttal, and Responsive RTP testimony in this proceeding?

A: Yes.

Q: What is the scope of your Rebuttal Testimony?

A: We discuss the Real Time Pricing (RTP) pilot for Commercial and Industrial (C&I) customers being proposed by PG&E in the RTP track of PG&E's GRC Phase II, which we will refer to as the C&I RTP Pilot. We reply to the Responsive RTP Testimony filed by Cal Advocates, CALSSA-Enel X, and PG&E, and discuss two stipulations SBUA has joined in the closely related DAHRTP-CEV Pilot proposed in A. 20-10-011.

Q: What issues do you address?

A: We address two elements of the rate design proposed for the C&I RTP Pilot, the marginal generation capacity cost (MGCC) and revenue neutral adder (RNA). We also discuss which rates should be included in the C&I RTP Pilot. We also respond to other parties' proposals with respect to eligibility, timing and cost recovery issues.

Our testimony does not address the proposal by CALSSA-Enel X to expand the C&I RTP Pilot to include residential customers.

Q: Please summarize your responses to ALJ Doherty's questions.

A: ALJ Doherty encouraged parties to address six questions in the August 27, 2020 ruling. A brief summary of our responses and references to where those questions are addressed in testimony is presented in Table 1.

Table 1: Responses to ALJ Doherty Questions

Question	Response
1) Benefits of RTP rate and customer interest	SBUA believes that small business interest in an RTP rate should be tested in the pilot, and that they may respond to bill savings opportunities from an RTP rate by investing in new load management technologies and practices, particularly as supported by third-party providers. (Responsive, pp. 3-8; Reply, pp. 8-10) SBUA is not greatly concerned that small businesses may be exposed to excessive price risks. (Responsive, pp. 12-14)
2) Tracking and addressing cost-shifts / undercollection	SBUA agrees with Cal Advocates that over- or under-collections should be recovered from pilot participants (Reply, p. 16)
3) Review of other RTP rates	SBUA agrees that PG&E's testimony addresses this question adequately.
4) Estimated cost	SBUA agrees that PG&E's testimony addresses this question adequately.
5) Design of rates and bill impact analysis	SBUA recommends that the C&I RTP Pilot should include an RTP rate overlay for a rate intended for small business, preferably schedule B-6. (Responsive, pp. 8-9; Reply, pp. 13-14) SBUA agrees with the rate design structure proposed by PG&E, including a wholesale energy rate (MEC), capacity rate (MGCC), revenue neutral adder (RNA) including a fixed REC amount. The PCIA portion of the generation rate should be collected separately as provided in the GRC II Settlements. (Responsive, p. 18) SBUA agrees with PG&E's proposal to use day-ahead prices from CAISO to recover the MEC element. (Responsive, pp. 17-18) SBUA supports conducting a study to develop the MGCC element. (Reply, pp. 3-4) SBUA recommends that the RNA adder should use either a fixed class or a TOU scalar method. (Reply, p. 21) With respect to bill impact analysis, SBUA does not have the data or models required to complete this work.
6) RTP pilot structure	SBUA generally supports PG&E's C&I RTP Pilot. (Responsive, pp. 16-17) SBUA recommends that the C&I RTP Pilot should not end with customers being automatically transitioned off the RTP rates. (Responsive, pp. 12) SBUA does not object to an enrollment cap and supports initiating the rate outside of the summer months. (Reply, p. 14) SBUA agrees with Cal Advocates that costs should be recovered through the PPP charge. (Reply, p. 14-16)

Q: How have your recommendations regarding RTP rate design for PG&E changed since you filed your Responsive RTP Testimony in this proceeding?

A: Since filing our Responsive RTP Testimony, we have entered into two stipulations with respect to PG&E's proposed DAHRTP-CEV Pilot. PG&E has also provided data responses with further information about the design of the revenue neutral adder for the C&I RTP Pilot. Considering these stipulations, new data, and the testimony of other parties, we have adopted the following revised or additional recommendations.

1. Instead of recommending that the Commission adopt our proposed MGCC rate element design, the study described in the MGCC Rate Design Stipulation should be completed and considered in determining the RTP rate design. Section I.A of this Reply Testimony updates Section VI of our Responsive RTP Testimony. Accordingly, the findings recommended at the end of Section IV of our Responsive RTP Testimony should not be adopted until confirmed by the study.
2. We have updated our recommendation with respect to the RNA based on the additional information, and now recommend either the fixed class or TOU scalar method described in Section IV of this Reply Testimony. We continue to support the findings recommended in Section VII of our Responsive RTP Testimony.
3. We now recommend prioritizing schedule B-6, with a second choice of schedule B-10-R, as discussed in Section II. We no longer recommend prioritizing schedule B-1-ST as suggested in Section II of our Responsive RTP Testimony.
4. We support the recommendations of CALSSA to initiating the C&I RTP Pilot outside of the summer months and do not object to an enrollment cap, as discussed in Section III of this Reply Testimony.

5. We also agree with Cal Advocates that costs should be recovered through the PPP charge, but that over- or under-collections should be recovered from pilot participants, as discussed in Section III of this Reply Testimony.

A. MGCC Rate Design Stipulation

Q: Please describe the MGCC rate design stipulation and explain the reasons you support its application to this proceeding.

A: In the MGCC rate design stipulation (Attachment 4), Cal Advocates, SBUA, and PG&E have agreed to undertake a study of issues that will inform the design of the MGCC element in an RTP rate for the DAHRTP-CEV Pilot. The study will "analyze the relationship of the following variables to the condition of the CAISO grid:

6. Hydro year conditions, and the definition and weighting of the hydro variable in the calculation of Adjusted Net Load (ANL),
7. CAISO restricted maintenance operations (RMO),
8. Day-ahead CAISO Flex Alerts and CAISO Alerts events,
9. Other CAISO warning and emergency events,
10. The Peak Capacity Allocation Factor (PCAF) threshold, and
11. The functional form of PCAF weighting above the PCAF threshold."[1]

Due to limitations on public information from CAISO, it is not clear that this evaluation will result in a clear outcome, but we believe that the study will help parties improve, and help the Commission evaluate, proposals for MGCC rate design.

As stated in the stipulation, "The Stipulating Parties believe that the analyses will provide useful information to inform the development of a real time pricing (RTP) rate for the CEV Pilot, and also of the MGCC element for the RTP pilot for

[1] Attachment 4, pp. 1-2.

Commercial and Industrial (C&I) customer[s] being considered in the RTP track of PG&E's GRC Phase II (the GRC II Pilot)."[2]

Even if there is no formal stipulation or settlement in this proceeding, the Commission should not decide the MGCC rate design based on the current record in this proceeding. While we believe the rate design proposed in our Responsive RTP Testimony is worthy of serious consideration, we expect that the results of the study will inform all parties as to the best approach.

Furthermore, PG&E has developed a schedule for conducing the study without delaying the DAHRTP-CEV Pilot (Attachment 5). We expect that the study schedule is consistent with the schedule for the GRC II Pilot.

The MGCC rate design stipulation includes SBUA, PG&E and Cal Advocates, who have filed Responsive RTP Testimony. CALSSA-Enel X, the other party that submitted Responsive RTP Testimony, states, "In the event that parties propose methods to reduce year-to-year variability in MGCCs, we also support collaboration among the parties to come to an agreeable resolution."[3] All four testifying parties are generally in agreement on this issue.

We recommend that the study resulting from the stipulation should be included in the record and considered by the Commission in its determination of the MGCC element for the RTP rate design for the C&I RTP Pilot.

[2] Attachment 4, p. 2.

[3] CALSSA-Enel X Responsive Testimony, p. 7, lines 2-4.

B. Revenue Neutral Adder Stipulation

Q: Please describe the stipulation on Time-Differentiation of the Revenue Neutral Adders (RNA) for the DAHRTP-CEV Pilot Rate.

A: In the RNA stipulation (Attachment 6), SBUA, Enel X and PG&E have agreed to support a time-differentiated RNA element in the RTP rate that, to the extent possible, would result in expected revenues close to those that would have been collected through the base BEV schedules. Minimizing the difference between the base and RTP rate designs is important because other alternatives could result in unnecessary cost shifts and windfall benefits to structural adopters.

A structural adopter is a customer that benefits from the RTP rate due to its existing load shape, even without responding to the rate design and shifting load away from high-cost hours. The RNA stipulation follows pending GRC Phase II Settlements in providing that the PCIA and REC elements of the generation rate cannot be time-differentiated. The RNA stipulation provides for a time-differentiated TOU RNA that is appropriate for the DAHRTP-CEV rate.

Q: Should the RNA stipulation be applied to this proceeding?

A: No. The RNA stipulation states that it is not precedential for other rate proceedings. Furthermore, the base BEV schedules are unusual in that the TOU differential between the peak and off-peak rates is larger than would normally be justified by marginal cost. This special circumstance means that the specific RNA solution recommended in the DAHRTP-CEV RNA stipulation should not be applied to the C&I RTP Pilot.

II. Rates for the C&I RTP Pilot

Q: Which C&I rates should include an RTP rider?

A: PG&E's C&I RTP Pilot proposal would add an RTP rider to the base B-19 and B-20 tariffs. CALSSA-Enel X recommend expanding C&I rates to also include B1-ST.[4] Cal Advocates does not take a specific position regarding which C&I rates should be included.[5]

In our Responsive RTP Testimony, we recommended expanding the pilot to all rate schedules, but at a minimum including B1-ST and B-6 rate schedules to serve small businesses who have demonstrated an interest in alternative rates.

Based on information we have learned since filing our Responsive RTP Testimony, we have refined our opinion regarding the priorities for pilot rates for C&I customers. We believe the pilot rates should be selected based on four criteria.

1. The total number of rates should consider the cost and logistical challenges of building out the rates in PG&E's billing system.[6] We do not know how many rates would be reasonable, but for purposes of our testimony we will assume a limit of two or three rates.
2. The rates should be selected to help answer the question, "Which customer types are interested in RTP and can benefit, and why are some customers unwilling to participate?"[7] This is the first C&I RTP Pilot objective listed by PG&E in its Supplemental RTP Testimony. PG&E's initial proposal to

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[4] CALSSA-Enel X, Responsive RTP Testimony, p. 5, lines 3-4.

[5] Cal Advocates, Responsive RTP Testimony, p. 3, lines 5-7.

[6] In its Supplemental RTP Testimony, PG&E explains the challenges related to the replacement of its Advanced Billing System, including requirements resulting from other proceedings such as the NEM Successor Tariff. PG&E, Supplemental RTP Testimony, Ch. 5, p. 8, FN 7; p. 19, line 12 – p. 21, line 27.

[7] PG&E, Supplemental RTP Testimony, Ch. 1, p. 24.

include only B-19 and B-20 rates would exclude small businesses from these analyses, unless they opt into a tariff that is not designed for their circumstances.

3. To some extent, examining customer history could identify schedules with concentrations of customers who are likely to have an interest in an RTP pilot based on an interest in operating storage or load shifting in response to RTP rates. By customer history, we refer to records of storage interconnection, selection of rates designed to encourage load management, and other similar decisions. However, the C&I Rate Design Settlement includes significant changes to eligibility or design of several rates, including B-6, B-19-R, and B-19-S, so customer history may not fully inform the identification of promising rates to prioritize.[8]
4. Rate eligibility and non-generation rate components should be complementary to the purposes of an RTP pilot. Greater time-differentiation of distribution energy rates should increase a customer's economic incentive to invest in battery storage, battery management, and complementary load-shifting activities. In contrast, co-optimizing minimization of a monthly demand charge and the variable and uncertain energy charge would be challenging, presenting a participation barrier and reducing the effectiveness of the RTP price signals.

Q: How should the C&I RTP Pilot investigate which customer types are interested in RTP rates and why are some customers unwilling to participate?

A: Large, medium, and small customers may be interested in RTP rates. PG&E reasonably observes that its largest C&I customers are currently better equipped to

[8] PG&E, Commercial and Industrial Rate Design Supplemental Settlement Agreement (April 13, 2021). (Hereafter, C&I Rate Design Settlement.)

respond to an RTP rate than smaller ones.[9] Our Responsive RTP Testimony explains why the C&I RTP Pilot should be used to determine if small businesses would participate in RTP, if given the chance.

The potential for recruitment and engagement of small businesses may be difficult to infer from surveys or the experience with large customers. We agree with CALSSA-Enel X that PG&E has not shown "why additional research and benchmarking is needed before also offering the rate option to other customer classes. If the intent is to gauge customer interest in, and response to, an opt-in dynamic rate among customers, then actually extending a rate offering to customers would be better suited to this end rather than a consultant study that deals in hypotheticals."[10]

Surveying small businesses may be of limited value if, as we anticipate, the many small businesses would participate in response to bundled offers from third-party vendors of energy-management and storage systems. Small businesses may not be informed about the market until these offers are made, which would follow the creation of an appropriate RTP tariff.

Marketing of energy storage and automation services to small businesses may increase in response to a C&I RTP Pilot. CALSSA-Enel X notes that, "for energy storage and device automation providers to maintain internal capacity to provide solutions to customers, employees need to be trained to develop expertise in real time pricing, whether they are engineers, system managers, financing analysis, or customer service representatives."[11] Investments in these products and services are a necessary precursor to determining whether small businesses will select and respond to an RTP rate.

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[9] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 5-14.

[10] CALSSA-Enel X, Responsive RTP Testimony, p. 3, lines 11-16.

[11] CALSSA-Enel X, Responsive RTP Testimony, p. 5, lines 20-23.

Similarly, the experience of large customers may not provide much information about small business participation. Third-party offerings to small businesses will usually be very different from those marketed to large customers, in terms of the user interface and customer support, size and capabilities of storage systems, as well as the associated software and hardware.

The C&I rates should be selected for the C&I RTP Pilot to provide the best possible opportunity for participation by C&I customers representing a wide range of sizes and sectors. The Commission should reject PG&E's proposal to limit the pilots to the customers who will have the greatest potential individual impact on load.

Q: How should the C&I Rate Design Settlement be considered when selecting rates?

A: Three C&I Rate Design Settlement terms are relevant to the selection of RTP pilot rates, including B-6, B-19/B-20 Option R, and B-10R.

First, the B-6 rate will now be (nearly) fully time-differentiated (fully EPMC-scaled). The B-6 rate is available to all B-1 customers and has no demand charges. These changes make the B-6 rate a good choice for the RTP pilot.

Second, the settlement terms would significantly expand eligibility for B-19/B-20 Option R, which is the rate option that removes generation demand charges and substantially reduces TOU period distribution demand charges. (Monthly maximum distribution demand charges are unchanged.) Eligibility would be broadened from just renewable generators to include a broader range of customers, as follows.

> Option R shall be expanded to specifically include customers with solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP, customers with behind-the-meter storage whether it is paired with such renewable distributed generation or it is stand-alone storage, and Permanent Load Shifting (PLS) technologies.[12]

[12] C&I Rate Design Settlement, p. 10.

Option R would be a good option for many potential RTP participants who wish to leverage battery storage, fuel cells, or PLS technologies such as ice-storage and other thermal-energy storage devices, or the pumping and storage of water (as defined in Resolution E-4098). The two downsides of using Option R rates for the C&I RTP Pilot are that they include a significant maximum distribution demand charge, and that customers whose load shifting strategy does not include fuel cells, battery storage, or PLS technologies are ineligible for the rate.

Third, PG&E agreed to create rate option B-10-R, with has no special eligibility requirements. The rate will have fully time-differentiated (fully EPMC-scaled) generation and distribution energy rates but will maintain the distribution maximum demand charge adopted for B-10. Because option B-10-R is a new rate, prioritizing it for the C&I RTP Pilot means that the historical data available to reference in the evaluation of the RTP rate would be very limited.

In addition to these three changes, it is our understanding that PG&E has recently revised the process for participating in B-19/B-20 Option S, which may increase customer acceptance of this rate. Option S has lower distribution demand charges than Option R. However, fewer customers would be eligible for Option S than for Option R, since participating customers must have storage systems representing at least 10% of the customer's peak demand.

Each of these four changes results in the rates being significantly more compatible with battery storage, PLS, and other load-shifting methods. Even before an RTP rate is adopted, PG&E's existing rate designs are already providing customers with more economic incentive to engage in grid-supporting load management. Consideration of customer enrollment in existing rates should not be viewed in isolation from these trends.

Q: How do you suggest considering rate eligibility and non-generation rate components in the selection of rate schedules for the C&I RTP Pilot?

A: In Table 2, we have laid out some of the key information required to identify the tradeoffs in selecting C&I rates. There are trade-offs between maximizing eligibility and choosing rates with RTP-friendly non-generation rate components, so selecting C&I rates for the C&I RTP Pilot will require balancing of those objectives.

Table 2: Comparison of C&I Rate Suitability for RTP Pilot

Rate	Recent Design Changes	Eligibility	T&D Demand Charges[13]		Summer Peak / Off-Peak T&D Energy Rate Differential
			Max	Summer Peak	
B-1	None	Demand < 75 kW	$ 0.00	$ 10.87	$ 0.00
B-1-ST	None	Requires 4.8 kWh storage, 15,000 enrollment cap	$ 3.64	$ 0.00	$ 0.11
B-6	Enhanced time differentiation	Optional rate for B-1 customers, no participation limit	$ 0.00	$ 0.00	$ 0.05
B-10	None	Demand < 500 kW	$ 13.59	$ 0.00	$ 0.00
B-10-R	New rate	Optional rate, no participation limit	$ 13.59	$ 0.00	Fully differentiated[14]
B-19/B-20	None	B-19: < 1 MW	$ 21.44	$ 10.87	$ 0.00
B-19/B-20-R	Expanded eligibility	Renewable generation, storage, or PLS technology required; cap of 600 MW across all rate classes	$ 21.44	$ 2.72	$ 0.07
B-19/B-20-S	Improved enrollment process	Storage > 10% of peak demand; cap of 50 MW per rate schedule	Off-peak	Daily[15]	Similar to Option R

Note: For the three B-19/B-20 class rates, the rate information is for B-19. B-20 rates are similar.

Sources: Review of PG&E tariff requirements; C&I Rate Design Settlement;
PG&E response to SBUA_007-Q01-Q03Rev01, attachment GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch01.xlsx

[13] Based on PG&E's recommended marginal costs, other parties' recommendations differ.

[14] B-10-R rates were not requested from PG&E. Since B-6 is nearly fully-differentiated, it is likely that the B-10-R rate differential would be similar to the differential for B-6.

[15] B-19/B-20-S rates were not requested from PG&E. Summer peak demand charge will apply to daily maximum load.

PG&E's proposal for the B-19 and B-20 rates maximizes eligibility, since any B-1 or B-10 customer may opt into B-19. On the other hand, those two rates have the highest demand charges, which would overly complicate customer response, and no differentiation of non-generation energy rates, which would dilute the price signals. The B-10 or B-19R rates could also provide broad eligibility, with a lower summer-peak demand charge but a high maximum demand charge.

The B-6 rate provides the simplest, most-compatible rate design, but is only open to customers with loads under 75 kW. With nearly full differentiation of TOU rates and no demand charges, energy optimization by customers and third-party providers would be relatively simple.

The B-19-S rate is more complex than B-6, and will have demand charges. But the daily peak period demand charge on this rate will be less challenging to co-optimize with RTP price signals than a monthly demand charge. However, with a 50 MW load cap and significant storage requirement, it may be less accessible to customers.

Q: Which C&I rates do you believe should be priorities for the RTP pilot?

A: After reviewing this additional evidence, we continue to recommend the B-6 rate as the most suitable for small business customers. We understand that there has been limited interest in B-1-ST up to this point and would prefer a rate that is accessible to customers without storage since some may use other load shifting techniques. Thus, we withdraw our earlier recommendation to include B-1-ST in the pilot.

Our second choice would be B-10-R. This has the advantage of being available to medium power & light customers with a modest demand charge. However, we prefer B-6 because we believe that B-10 customers could be accommodated on a B-19-R rate. Requiring B-1 customers to opt-in to B-10-R to participate in the new RTP rate also adds the complication of taking on demand charges and potentially higher monthly customer charges.[16]

Either B-6 or B-10-R should be offered in the RTP pilot to make it accessible to small business customers. We take no specific position on which rates, if any, should be prioritized for residential or large commercial customers.

III. Eligibility, Timing and Cost Recovery

Q: Do other parties agree with your recommendation that customers should not be automatically transitioned back to the Otherwise Applicable Tariff after two years?

A: Yes. CALSSA recommends an "ongoing rate with an enrollment cap."[17] This is similar to our recommendation for maintaining the rate unless the Commission approves termination. We understand that PG&E is not concerned about excessive enrollment, but do not object to a temporary enrollment cap to avoid large impacts from unintended consequences.

Q: Do any parties make eligibility, timing or cost recovery recommendations that you agree with?

A: Yes. CALSSA suggests that the rate should go live outside of the peak summer months, which we support.[18] It would be difficult for customers and third-party vendors to optimize RTP rate response in the middle of the summer.

Cal Advocates recommends that incremental pilot and research costs should be recovered through the Public Purpose Programs (PPP) charge using the equal cents

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[16] Note that B-6 can be characterized as an Option R rate for B-1 customers.

[17] CALSSA-Enel X, Responsive RTP Testimony, p. 5, lines 26-28.

[18] CALSSA-Enel X, Responsive RTP Testimony, p. 6, lines 4-6.

per kWh allocator instead of through distribution rates.[19] We agree with Cal Advocates that cost recovery should occur through the PPP charge because it supports "broad environmental and social goals." In addition to the evidence included in Cal Advocates' testimony, we would call the Commission's attention to two recent actions.

First, the California Energy Commission is undertaking the 2020 Load Management Rulemaking (Docket #19-OIR-01) to expand on efforts to increase efficiency and demand flexibility in California's electricity grid. In April, CEC staff presented four proposed amendments to the Load Management Standards, including "Develop and submit locational rates that change at least hourly to reflect marginal wholesale costs."[20]

The CEC staff placed these amendments in "context," referring to state goals to achieve 100% emissions-free vehicles by 2035 and have a 100% carbon-free grid by 2045, further noting that "Carbon-free supplies tend to be inflexible." Thus, CEC's proposed load management standards would provide flexibility on the demand side.

Second, CPUC Energy Division staff have released a draft *DER Action Plan 2.0 Update for 2021-2026*. Of the four tracks discussed in the action plan, the "Load Flexibility and Rates" track is heavily focused on RTP rates, mentioning them in thirteen of the twenty action elements. For example, one draft action element states, "By 2024, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported

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[19] Cal Advocates, Responsive RTP Testimony, p. 15, lines 2-5.

[20] Karen Herter, *Proposed Amendments to the Load Management Standards*, Draft Staff Analysis (April 12, 2021), Efficiency Division, California Energy Commission, p. 11.

by ME&O programs to match various customer preferences and engagement levels."[21]

The DER Action Plan's goal "is to ensure that DER policy implementation in support of SB 100 and California's energy and climate goals is coordinated across proceedings related to grid planning, affordability, load flexibility, market integration, and customer programs."[22]

Development of RTP rates has become an important component in multiple public-purpose initiatives and will lead to benefits for all customers.

Q: What about recovery of under- or over-collections?

A: Cal Advocates recommends that any under- or over-collections should be recovered from pilot participants.[23] As noted in our Responsive RTP Testimony, PG&E suggests that this problem is likely to be inconsequential in a pilot, allowing for further discussion of the method for adjusting these rates in Energy Resource Recovery Account (ERRA) proceedings once data on C&I RTP Pilot customer behavior becomes available after the pilot. If this matter is addressed now, we agree with Cal Advocates that pilot participants themselves should be responsible for cost recovery through any reasonable process.

Q: Do any parties make eligibility, timing or cost recovery recommendations that you do not support?

A: CALSSA recommends that customers be allowed to participate in the RTP rate and remain in the Base Interruptible Program (BIP). CALSSA explains that BIP

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[21] CPUC Energy Division, *Draft Distributed Energy Resources Action Plan: Aligning Vision and Action* (July 23, 2021), p. 8.

[22] CPUC Energy Division, *Draft Distributed Energy Resources Action Plan: Aligning Vision and Action* (July 23, 2021), p. 3.

[23] Cal Advocates, Responsive RTP Testimony, p. 19, lines 3-10.

dispatches are relatively rare events and that an RTP customer could "set their consumption and discharged profile based on the DA RTP, *and* still respond to a BIP dispatch."[24]

While we agree that it is theoretically possible to respond to a BIP dispatch on top of an RTP profile, we think this level of complexity may be premature. It has not yet been proved that PG&E can measure an individual customer's response to RTP.

Once PG&E has determined the accuracy of its measurement of individual customer response to RTP, then the potential for additional BIP dispatch can be assessed.

IV. Design of the Revenue Neutral Rate Adder

Q: Please summarize your prior recommendation with respect to the revenue neutral rate adder.

A: In our Responsive RTP Testimony, we recommend that the Commission modify PG&E's C&I RTP Pilot proposal by replacing the flat revenue-neutral rate adder (RNA) with TOU-period generation rates.

Q: How have your recommendations changed?

A: We continue to believe that non-marginal generation costs (which will not be recovered through the RTP charges) should be collected in a revenue-neutral fashion, and that a single flat adder for all rates is neither cost-based nor reflective of time-differentiation in the Otherwise Applicable Tariff (OAT).[25] We have reviewed several

[24] CALSSA-Enel X, Responsive RTP Testimony, p. 8, lines 13-17.

[25] The PCIA generation cost component would be collected from both RTP and non-RTP customers as a flat rate, and the RPS generation cost component should also be collected within the RNA as a flat rate.

additional approaches to designing an RNA and believe that there are several good options.

Q: How should the RNA be designed?

A: We recommend four criteria for selecting an RNA.

First, the RNA should avoid under- or over-collection for specific rates. Designing the RNA around the system average is misaligned with the class-specific rate design practices used in the C&I Settlement.

Second, the RNA should avoid complicated structures, such as inverted rates, that could confuse customers. An inverted RNA rate would have a lower (perhaps negative) rate for the peak period than for the off-peak period.

Third, the RNA should avoid structural adoption incentives, such as an effective reduction of the peak period rate on typical days.

Fourth, the RNA should increase intra-day rate variability. Increased variability in daily rates will provide economic opportunities for storage technologies. Nonetheless, an increase in intra-day variability should not be so large that it results in over-incentivizing load shifts, which could result in cost shifts.

Q: What are some of the RNA options you have evaluated?

A: Among the RNA options we have evaluated, the following four provide a good illustration of the potential options.

1. Uniform, system average adder – PG&E's original flat adder proposal
2. Uniform, rate-specific flat adder – Modified version that varies the adder by rate class
3. TOU differentiated adder - Revenue neutrality by TOU period and rate

4. TOU differentiated scalar – Revenue neutrality by rate, scaling forecast MEC and MGCC revenues by rate period[26]

The RNA for each of these options is shown in Table 3, and the total of the RNA and the average RTP price for the TOU period is shown in Table 4.[27].

[26] The scalar is the EPMC (equal percentage of marginal cost) scalar used to develop the base generation rates. This scalar is multiplied by the expected MEC and MGCC revenues for each TOU rate period to determine the TOU scalar RNA. The scalar may be positive or negative, and the MECs may also be negative or positive. For example, Table 4 shows that in the case of the B-6 Super Off-Peak TOU scalar RNA, both the scalar and the MECs are negative, so the resulting RNA is positive.

[27] This is equivalent to the complete generation rate excluding the flat PCIA.

Table 3: Comparison of Revenue Neutral Adders by TOU Period[28]

	B-6				B-19-R			
	Flat Adder	Class Adder	TOU Adder	TOU Scalar	Flat Adder	Class Adder	TOU Adder	TOU Scalar
Summer								
Peak	0.020	0.000	-0.025	-0.009	0.020	0.025	0.056	0.086
Partial Peak	Not applicable				0.020	0.025	0.025	0.032
Off Peak	0.020	0.000	-0.002	0.001	0.020	0.025	0.023	0.016
Winter								
Peak	0.020	0.000	0.010	-0.001	0.020	0.025	0.030	0.033
Off Peak	0.020	0.000	0.003	0.002	0.020	0.025	0.020	0.016
Super Off Peak	0.020	0.000	0.049	0.004	0.020	0.025	0.017	0.002

Table 4: Comparison of Total Generation Rates by TOU Period, Assuming Expected DAHRTP

	B-6					B-19-R				
	Base Rate	Flat Adder	Class Adder	TOU Adder	TOU Scalar	Base Rate	Flat Adder	Class Adder	TOU Adder	TOU Scalar
Summer Peak	0.232	0.277	0.257	0.232	0.246	.224	0.187	0.192	0.223	0.241
Partial Peak	Not applicable					.089	0.084	0.089	0.089	0.096
Off Peak	0.059	0.081	0.061	0.059	0.062	.052	0.049	0.054	0.052	0.046
Winter										
Peak	0.092	0.102	0.082	0.092	0.082	.093	0.083	0.088	0.093	0.094
Off Peak	0.052	0.069	0.049	0.052	0.051	.052	0.052	0.057	0.052	0.050
Super Off Peak	0.016	-0.014	-0.034	0.015	-0.027	.017	0.020	0.025	0.017	0.005

[28] PG&E estimates from Attachments 7(a) (Base Rate), 7(b) (Flat Adder and TOU Scalar), 7(c) (TOU Adder) and 8 (Class Adder).

Q: What are your conclusions about the RNA options you have evaluated?

A: First, the flat adder has evident problems. As shown in Table 4, for the summer peak period, the flat adder results in an expected B-6 rate that is higher than the base rate, but also an expected B-19-R rate that is lower than the base rate. In the case of B-19-R, this suggests a potential for customers to switch rates to achieve a structural advantage – reducing their bill without load shifting as intended by the rate design.

While the TOU adder option performs well in Table 4, it has an inverted RNA rate design as shown in Table 3. If on-peak rates are greater than off-peak rates, that could confuse customers.

This suggests that either the class adder or the TOU scalar might be better choices. The class adder is simpler, but the TOU scalar provides a somewhat stronger pricing signal to load shift away from the peak period. However, the increase in intra-day variability with the TOU scalar might be viewed as in over-incentivizing load shifts.

On balance, while the TOU adder and the class adder are reasonable options, we now favor the TOU scalar as a modest improvement on the TOU adder option we recommended in our Responsive RTP Testimony as it enhances the load shift modestly while avoiding the inverted rate design.

Q: Does this conclude your testimony?

A: Yes.

Attachment 1

Application No.: A.20-10-011
Exhibit No.: PG&E-20
Date: June 1, 2021

Joint Stipulation on Study for MGCC Rate Design Issue

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time and Pilot to Evaluate Customer Understanding and Supporting Technology.	Application 20-10-011 (Filed October 23, 2020)

Joint Stipulation on Study for MGCC Rate Design Issue

I. INTRODUCTION

PARTIES STIPULATING: The parties sponsoring this stipulation are the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Small Business Utility Association (SBUA), and Pacific Gas and Electric Company (PG&E) (together Stipulating Parties). Cal Advocates and SBUA have authorized PG&E to submit this stipulation on their behalf consistent with Rule 1.8 (d) of the Commission's Rules of Practice and Procedure.

SCOPE OF STIPULATION: The Stipulating Parties have taken different positions in this proceeding regarding the development of a marginal generation capacity cost (MGCC) component for a real time rate to be used in PG&E's pilot for commercial electric vehicles, the DAHRTP-CEV pilot (CEV Pilot). The Stipulating Parties have entered into this stipulation to make clear their support for a research study (Study) to analyze the relationship of the following variables to the condition of the CAISO grid: 1) hydro year conditions, 2) the definition and weighting of the hydro variable in the calculation of Adjusted Net Load (ANL), 3) CAISO restricted maintenance operations (RMO), 4) day-ahead CAISO Flex Alerts and CAISO alerts events, 5) other CAISO warning and emergency events,

6) the Peak Capacity Allocation Factor (PCAF) threshold, and 7) the functional form of PCAF weighting above the PCAF threshold,[1] using SERVM data that Energy Division would provide. The Stipulating Parties believe that the analyses will provide useful information to inform the development of the MGCC element of a real time pricing (RTP) rate for the CEV Pilot, and also of the MGCC element for the RTP pilot for Commercial and Industrial (C&I) customer being considered in the RTP track of PG&E's GRC Phase II (the GRC II Pilot). The Stipulating Parties agree that it is very important that the findings of the Study, when complete, be included in the record and considered by the Commission in its determination of the MGCC element for the real-time rate design in this proceeding.

II. STIPULATED STUDY

PG&E has used its generation peak capacity allocation factor (PCAF) method to develop generation rates for TOU rates and allocate MGCC among customer classes in revenue allocation for several years,[2] based on adjusted net load (ANL)[3] above a threshold. PG&E's ANL/PCAF method includes a hydro variable in the definition of ANL and uses all weather year scenarios in the calculation of the threshold and the "PCAF denominator." Cal Advocates has proposed to reflect different hydro year assumptions than used by PG&E, by limiting the selection of weather years used to calculate both the PCAF threshold and the PCAF denominator in the MGCC allocation to those simulated weather years with similar hydro conditions to the current year.

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[1] This refers to the shape of the PCAF risk curve above the PCAF threshold, such as whether the risk curve should increase linearly with increasing adjusted net load (ANL) or if it would more accurately match the underlying hourly capacity risk by using a non-linear function.

[2] There is only one customer class in the DAHRTP-CEV pilot. Therefore, allocation among customer classes is not relevant for purposes of the pilot in A.20-10-011.

[3] ANL refers to system-level metered load net of all solar and wind generation, small and large hydro, nuclear, geothermal, biomass and biogas generation. None of the Stipulating Parties contest the general use of PG&E's ANL/PCAF method for these purposes.

Cal Advocates and SBUA also each propose a different adjustment for how MGCC would be allocated to hours. Cal Advocates proposes to assign 13 percent[4] of the MGCC to the hours 3-9pm during which CAISO issues a day-ahead Flex Alert or alert (CAISO alert) and only for hours for which PG&E's PCAF-based capacity prices do not meet or exceed a certain threshold, possibly with limits on the minimum and maximum number of hours called in each calendar year. The remaining MGCC value (87 percent of total)[5] would be assigned to hours based on PG&E's PCAF methodology. SBUA proposes to allocate the MGCC based on CAISO Flex Alerts, CAISO RMOs, and an ANL/PCAF method based on PG&E's hydro assumptions or with Cal Advocates hydro year modification, potentially using a different functional form for PCAF weighting above the threshold than PG&E's linear function, and/or using a different threshold than PG&E's 80 percent of scenario-averaged maximum annual ANL.

The Stipulating Parties agree that their different approaches are reasonable to evaluate, but that insufficient data is currently available to support more than a hypothetical evaluation of parties' different MGCC allocation proposals in terms of whether one proposal or some combination of the proposals would produce the best alignment with underlying hourly capacity shortfall risk for the CAISO system – which is essential to the construction of a meaningful, cost-based capacity price signal in the DAHRTP rate.

To address the lack of data, SBUA has recommended PG&E perform a Study quantifying the relationship between various alternative forms of its PCAFs and reliability metrics.[6] PG&E recognizes the value of such a Study and proposes including

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4 That is, Cal Advocates proposes to assign the marginal capacity costs associated with the 15% planning reserve margin (PRM) to an hourly capacity component based on CAISO Alerts and Flex Alerts. 15% / 115% = 13.04%.

5 100%-13%. See footnote 4.

6 *See* SBUA Direct Testimony, pp. 11-12.

further variables in the Study such as 1) the definition of the hydro variable,[7] 2) the weighting of the hydro variable,[8] 3) variations of Cal Advocates' reliability Capacity Peak Pricing (reliability CPP) or CAISO Alert-Based Adjustment (CABA) proposal, as discussed in PG&E's rebuttal testimony,[9] and 4) SBUA's proposed inclusion of RMOs.

To perform the Study, PG&E will need system-wide historical and/or forecasted hourly capacity shortfall (reliability) metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE), and/or reserves shortfalls data, which PG&E believes is available through SERVM data which the Commission's Energy Division retains.[10] Upon delivery of this data to PG&E, the study can likely be completed within five to six months, with participation by Cal Advocates, and SBUA.[11]

It would also be valuable to the Study to obtain more detailed information from CAISO regarding the standards that it applies to initiate an Alert, Warning or Emergency (AWE) event, both in general and with respect to historical events. Among the actions and efforts that the CAISO, CPUC and CPUC are taking to prepare California for extreme heat waves without having to resort to rotating outages, "[t]he CAISO, CPUC, and CEC are planning to enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand side efforts during extreme heat events."[12]

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7 For instance, PG&E's marginal energy cost (MEC) model currently uses a 25-day rolling average of average daily hydro generation and daily maximum hydro generation. The averaging (25-day, daily) and type (average or maximum) may need to be changed to most accurately represent hydro's contribution to capacity needs. *See* PG&E Rebuttal Testimony, pp. 2-8:18-28 to 2-9:1-6.

8 PG&E's MEC model currently applies a 1.19 weighting factor to the hydro variable, based on a calibration using all hours from 2012 to 2019. However, PG&E believes that a weighting factor less than one may be more appropriate to model capacity risk, as hydro capacity is less dependent on annual inflow volume than is annual hydro energy.

9 *See* PG&E Rebuttal Testimony, p. 2-13:8-11.

10 *See* PG&E Rebuttal Testimony, p. 2-9:20-25.

11 PG&E states the study would require the first half of 2022. *See* PG&E Rebuttal Testimony, p. 2-9:14-17.

12 CAISO, CPUC, and CEC, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (January 13, 2021), pp. 1-2.

III. GOALS OF THE STUDY:

The purpose of the Study is to determine the fit between alternative formulations of hourly MGCC, as described above or as developed during the Study, and capacity shortfall (reliability) metrics.[13] The primary purpose of a real-time capacity price signal is to accurately reflect temporal (hourly) variations to the risk that there will be insufficient capacity to serve demand – and thus variations in the capacity costs at the margin of serving incremental load. The Stipulating Parties agree that the Study will provide a data-driven benchmark of which real-time capacity pricing proposals, or combinations thereof, most closely align with hourly capacity shortfall risk and with the costs PG&E incurs to serve marginal load. This would enable the DAHRTP pilot rate to send more effective forecast generation capacity price signals, increasing the potential benefits of the CEV Pilot. A more accurate generation capacity price signal could improve system reliability, and reduce the duration or magnitude of power outages during the extreme capacity shortfall events; and could also reduce cost shifting between participants and non-participants by ensuring that pilot participants pay as close as possible to the actual marginal costs incurred by PG&E (whether in the operating year or a subsequent year).

Additionally, the Study will help to identify the appropriate level of inter-annual variation in the DAHRTP pilot rate's MGCC price element. Parties' MGCC proposals result in differing levels of intra- and inter-annual variation in capacity prices.[14] By comparing the various proposals to reliability metrics and determining which proposals produce the best fit, the Study could indicate what level of intra- and inter-annual

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13 *See* SBUA Direct Testimony p. 11:10-14 and PG&E Rebuttal Testimony, p. 2-9:1-6.

14 See, for example, Table 1-8 on p. 1-27 of Cal Advocates' direct testimony comparing inter-annual variability in PCAFs between PG&E's and Cal Advocate's proposals under PG&E's 10 simulated weather years that comprise its 2021 DAHRTP rates forecast, and Figures 3 and 4 on pp. 17-21 of SBUA's reply testimony comparing highest priced hours between PG&E, Cal Advocates and SBUA proposals using PG&E's estimates of MEC and MGCC prices for 2017-2020.

variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years.[15]

IV. PROCEDURAL PROPOSAL

The Stipulating Parties would start work on the Study as soon as Energy Division makes the SERVM data available. Thereafter, the estimate for completion of the Study is 5 to 6 months. When the Study results are available, each Stipulating Party would use the results to develop its proposal for 1) allocation of the MGCC to hours, and 2) what factors should be used, e.g., CAISO Alerts, CAISO RMOs, and ANL/PCAF implementation.

Stipulating Parties' proposals can consider other criteria for inclusion of those factors into the MGCC price element of DAHRTP pilot rate, such as customer understandability and acceptance of the rate component. Other parties could also develop proposals for MGCC based on the results of the Study.

The Stipulating Parties would move for admission of the study results into the record of this proceeding. The Stipulating Parties anticipate that MGCC proposals allowed by this procedural step would be presented in in testimony, for decision by the Commission. The Administrative Law Judge could set limited hearings on the proposals, either on his or her own motion, or in response to a request by the Stipulating Parties for limited hearings on the MGCC proposals. Issues decided in the Commission decision for the DAHRTP-CEV pilot that are not related to the development of the MGCC or its allocation to hours, may not be relitigated in connection with this procedural process for the Study.

A key timing element is how soon the SERVM data can be obtained, i.e., the sooner the Study can begin, the sooner parties can provide their testimony on

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15 *See* PG&E Rebuttal Testimony p. 2-7:12-15.

incorporating the study results into the DAHRTP-CEV pilot rate. For this reason the Stipulating Parties have not included any specific dates in the Stipulation.

V. STIPULATING PARTIES' REQUEST FOR THE CURRENT JUNE 2021 PROCEEDINGS

The Stipulating Parties agree that a Commission decision based on the evidentiary record from the June 2021 hearings should not decide the MGCC issues addressed in this stipulation. The Stipulating Parties make this request to coordinate the inclusion of the study results and the preceding section IV Procedural steps in order to avoid confusion and potentially conflicting results if the MGCC issues to be studied were also addressed on the merits in a Commission decision on the upcoming June hearing record.

Allowing for inclusion and review of Study data in this proceeding prior to a Commission decision on MGCC design issues would reduce the likelihood that the Commission and parties will need to modify a decision reached without the benefit of Study data, should the Study findings warrant adjustment to the DAHRTP rate design.

The Stipulating Parties agree to waive cross-examination of their witnesses for the June 2021 hearings in A.20-10-011 on the MGCC issues covered by this Stipulation. The Stipulating Parties agree that each Stipulating Parties' testimony and cross-examination exhibits that have been served as of May 29, 2021 on the MGCC issues may go into the evidentiary record in A.20-10-011; but that the Stipulating Parties are not waiving their rights to cross-examine the witnesses on MGCC issues in future proceedings, including future proceedings that may address incorporation of the study results into the DAHRTP-CEV pilot rate.

The Stipulating Parties further request that in the Commission's decision in A.20-10-011, the Commission consider including the following findings:

1. The Commission finds that the Study will provide necessary data to set the MGCC element of the CEV RTP rate.

2. To perform the Study, PG&E will need system-wide historical and/or forecasted reliability metrics available through SERVM data which the Commission's Energy Division retains. Energy Division is directed to take the appropriate steps to provide the SERVM data to PG&E, and to allow parties participating in the Study to see the data, if necessary after signing a Non-Disclosure Agreement.

3. If additional information regarding standards that CAISO applies to initiate an Alert, Warning or Emergency (AWE) event can be obtained from the CAISO, both in general and with respect to historical events, the additional information may be useful input into development of the MGCC element of the real time rate.

Attachment 2

Application No.: A.20-10-011
Exhibit No.: PG&E-22
Date: June 3, 2021

Schedule Developed in Response to ALJ Doherty's Request during June 2, 2021 Hearings in A.20-10-011

In response to ALJ Doherty's request for a schedule that incorporates the Procedural Proposal in Exhibit PG&E-20, section V, and keeps the start of Pilot Phase 2 the same as in Exhibit PG&E-3, Table 3-1, PG&E has developed the schedule in the right hand column of the Table 1 below.

Table 1

Schedule Developed in Response to ALJ Doherty's Request during June 2, 2021 Hearings in A.20-10-011

Line No.	CEV RTP Activity	Current Schedule from Scoping Memo and Proposed Pilot Timeline in Supplemental Testimony	Proposed Schedule for MGCC Study and Limited Hearings and Revised Pilot Timeline Maintaining Pilot Launch in May 2023
1	Track 1 Evidentiary Hearings	June 1-4, 2021	
2	Track 1 Opening Briefs / Reply Briefs	July 2021 & August 2021	
3	MGCC Study Data Received from ED	N/A	August 2021
4	Track 1 Proposed Decision	Q3 2021	
5	Track 1 Final Decision	Q4 2021	
6	Conduct MGCC Study	N/A	August 2021 - December 2021 (5 months)
7	Track 2 Proposals / Testimony (PG&E plus all interested parties)	N/A	January 2022
8	Track 2 Rebuttal	N/A	February 2022
9	Track 2 Limited Evidentiary Hearings	N/A	March 2022
10	Track 2 Opening Briefs / Reply Briefs	N/A	April 2022
11	Track 2 Expedited Proposed Decision	N/A	April 2022 - May 2022
12	Track 2 Expedited Final Decision	N/A	May 2022
Pilot Timeline			
13	Pilot Phase 0 – Pilot Planning - Identify potential participants and technology partners, perform simulation/modeling of theoretical bill and load response impacts, finalize pilot project plan, including measurement and evaluation plan.	December 2021 – February 2022 (3 months)	June 2022 - August 2022 (3 months)
14	Pilot Phase 1 – Recruitment and Rate Technology Development – Complete Request for Proposal for technology partners, and enroll up to 50 customers, build and test customer technical integration with price discovery tools.	March 2022 – April 2023 (14 months)	September 2022- April 2023 (8 months)
15	Pilot Billing System Programming – expected to begin after Complex Billing System replacement is completed and stable. *Critical Path*	October 2022 – April 2023 (Current estimate) (7 months)	October 2022 – April 2023 (Current estimate) (7 months)
16	Pilot Phase 2 – Collect Pilot data and complete ongoing and interim analysis and gather lessons learned. Interim analysis and results shared January 2024.	**May 2023** – October 2024 (Dependent on line 4) (18 Months)	**May 2023** – October 2024 (Dependent on 15) (18 months)
17	Pilot Phase 3 – Analyze Pilot data and synthesize lessons learned.	November 2024 – January 2025 (3 months)	November 2024 - January 2025 (3 months)

Request:

PG&E and Parties will need the MGCC study data from the Energy Division by August 2021 to maintain a Pilot Phase 2 start date in **May 2023**. This assumes a five-month period to conduct the Track 2 MGCC study analysis, and a Track 2 Final Decision in May 2022. In the revised Pilot timeline, the timing for Pilot Phase 1 activities on line 14 is delayed and reduced from the schedule in PG&E Supplemental Testimony to enable the inclusion of MGCC study results in the determination of the MGCC calculation methodology plus the required additional Track 2 procedural steps. Slack had been built into Pilot Phase 1 timing due to critical path billing system work not being able to start before October 2022 and Track 1 Final Decision expected in Q4 of 2021. PG&E notes that Track 1 Proposed and Final Decision timing could have several months of flexibility, given critical path billing system work cannot start prior to October of 2022.

Attachment 3

Application No.: A.20-10-011
Exhibit No.: PG&E-21
Date: June 1, 2021

Joint Exhibit Presenting Stipulation between SBUA, Enel X and PG&E on Time-Differentiation of the Revenue Neutral Adders for the DAHRTP-CEV Pilot Rate

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time and Pilot to Evaluate Customer Understanding and Supporting Technology.	Application 20-10-011 (Filed October 23, 2020)

Joint Exhibit Presenting Stipulation between SBUA, Enel X and PG&E on Time-Differentiation of the Revenue Neutral Adders for the DAHRTP-CEV Pilot Rate

I. INTRODUCTION

As set forth in Pacific Gas and Electric Company's (PG&E) prepared testimony supporting its Application for Approval of its Proposal for a Day-Ahead Real Time Pricing and Pilot to Evaluate Customer Understanding and Supporting Technology, A. 20-10-011, PG&E has proposed a real time rate (RTP) that would be composed of i) a marginal energy cost based on CAISO day-ahead hourly prices, ii) a marginal generation capacity cost, and iii) a flat revenue neutral adder (RNA). Together these three elements would comprise the Day Ahead Hourly Real Time Pricing Pilot rate for Commercial Electric Vehicles (DAHRTP-CEV or RTP Rate) which would replace the generation component of PG&E's Schedule BEV rate.

Enel X and SBUA have presented testimony on the RNA which accepts the concept of the RNA, but their testimonies propose to time differentiate by TOU period. Enel X proposes to make the RTP rate a system of charges and credits that are an overlay on top of the existing generation rate.[1] SBUA proposes to let the RNA change by TOU period so that each period is revenue neutral to the base BEV rate.[2] Both proposals are mathematically equivalent and give the same total generation rate.

II. SCOPE OF STIPULATION: This Joint Stipulation is limited to the RNA adder solely for the DAHRTP-CEV pilot, and its effect on the RTP Rate for the pilot. MEC and MGCC are outside the scope of this Joint Stipulation.

III. PARTIES STIPULATING: SBUA, ENEL X, PG&E

[1] Enel X Opening Testimony, p. 9.
[2] SBUA Opening Testimony, pp. 16-18.

IV. TERMS OF STIPULATION

1. Based on the facts presented in PG&E's updated opening and rebuttal testimony identifying the components of the DAHRTP-CEV RNA[3] and the Joint Stipulating Parties further review of the concerns brought up by Enel X and SBUA regarding the comparability of the DAHRTP-CEV Pilot rate to the base BEV schedules,[4] the Joint Stipulating Parties agree to the following resolution regarding the RNA design:
    a. The RNA level of $0.05999/kWh presented in PG&E's updated opening testimony includes the bundled portion of Power Charge Indifference Adjustment (PCIA). When PCIA is removed from generation rates, as proposed in Advice Letter 5932-E and contained in the 2020 GRC II Residential Rate Settlement, the Agricultural Rate Settlement, and the Commercial and Industrial Rate Settlement (together the GRC Phase II Settlements)[5], the remaining RNA will be $0.01972/kWh, using revenue requirements as of May 1, 2020.[6]
    b. The PCIA is a flat rate and would not be subject to time differentiation as provided in the GRC Phase II Settlements.
    c. The RNA includes a $0.00519/kWh adder for Renewable Energy Certificates (RECs) which would not be time differentiated as the value of an REC only depends on the quantity of load and not the time at which it is consumed.
    d. The RTP Rate should never go below its marginal cost (the CAISO market rate plus the REC adder) after PCIA is removed. Therefore, the RNA should never be smaller than the REC adder.
    e. The base BEV schedules' generation rates include a larger time-of-use (TOU) differential between the peak and off-peak rates than would normally be justified by marginal cost. More cost-based generation rates would reflect a smaller TOU differential than the base BEV schedules.

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[3] PG&E Updated Testimony, Ch 2, p. 2-5; Supplemental Testimony, Ch 2, pp. 2-1 to 2-2.
[4] Enel X Opening Testimony, p. 8; SBUA Opening Testimony, pp. 16-19.
[5] 2020 GRC Phase II Residential Rate Settlement p. 6; Agricultural Rate Settlement p. 11; Commercial & Industrial Rate Settlement, p. 14.
[6] PG&E's 2020 GRC Phase II Rebuttal Workpapers list the bundled PCIA responsibility at $1,447,447,943 (File "RA_Rev_Alloc_GRC.xlsx", tab 'CALC_Gen_Alloc', cell D60. Dividing this revenue amount by the bundled load (35,944,653,361 kW) reduces the RNA by $0.04027/kWh. $0.05999 - $0.04027 = 0.01972.

f. The RTP Rate design is intended to be a more cost-based rate design than the generation rates in the base BEV schedules.

g. Using PG&E's proposed RNA, customers that do not or cannot shift their usage away from the peak period may be more likely to prefer the RTP Rate over the base BEV schedules because customers who can shift usage away from peak to the off-peak period can benefit more under the BEV schedules than under the RTP Rate.

2. The Joint Stipulating Parties agree that time differentiating the RNA to the extent possible to be closer to the base BEV schedules will help to offset the outcome of the RTP rate being more beneficial for customers that do not or cannot shift load away from the peak period. The Joint Stipulating Parties also agree that due to the fact that the GRC Phase II Settlements state that the PCIA and RECs cannot be time differentiated, there is not enough revenue left to differentiate the RNA to the degree originally proposed by Enel X and SBUA in their testimonies, which were filed prior to the GRC Phase II Settlements using the then-effective base BEV schedules. PG&E calculates that with the preliminary BEV load profiles it presented in rebuttal testimony, the maximum TOU differentiation the RNA adder could achieve is presented in Table 1.

Table 1: TOU Differentiating of the RNA Based on Preliminary BEV Load Profiles

TOU Period	Flat RNA without PCIA	TOU RNA without PCIA
Peak	$0.01972	$0.14304
Off Peak	$0.01972	$0.00519
Super-Off Peak	$0.01972	$0.00519

The Joint Stipulating Parties share some concern that the low RNA in the Super-Off Peak period could cause the overall generation rate to be negative after PCIA is removed, which potentially could occur when the CAISO market price goes below -$0.00519/kWh (after line losses). A negative overall generation rate might have unexpected consequences. For purposes of the DAHRTP-CEV Pilot, the Joint Stipulating Parties agree to a rate design with the potential for a negative generation rate, but recommend that any consequences be reviewed at the conclusion of the pilot.

3. The Joint Stipulating Parties agree that the values presented in Tables 1 are illustrative, based on May 1, 2020 revenue requirements, PG&E's 2020 GRC Phase II proposed marginal costs, and early BEV load profiles covering less than one year of actual usage. PG&E agrees to recalculate the RNA based upon updated revenue requirements, marginal costs, and load profiles before the RTP Rate becomes effective.
4. The Joint Stipulating Parties agree to waive cross-examination of each other's witnesses about the RNA at the June 1-4, 2021, evidentiary hearing scheduled in this proceeding;
5. The Joint Stipulating Parties agree that each Joint Stipulating Parties' testimony and cross-examination exhibits on the RNA that have been served as of May 29, 2021 on the RNA issues may go into the evidentiary record in A.20-10-011; but that the Joint Stipulating Parties are not waiving their rights to cross-examine the witnesses on RNA issues in future proceedings.
6. The Joint Stipulating Parties agree to present their Joint Stipulation as an exhibit for the June 1-4, 2021, evidentiary hearing, and to answer questions from interested parties and the Administrative Law Judge on the Joint Stipulation as appropriate, and;
7. The Joint Stipulating Parties agree and understand that the Joint Stipulation reflects facts that are specific to and applicable only to this DAHRTP-CEV proceeding and the Schedule BEV rates.
8. The Joint Stipulating parties agree that this Stipulation is not applicable to real time pricing for non-BEV customer classes or other rate schedules, and it does not set a precedent for other rate proceedings, including without limitation the 2020 GRC Phase II RTP proceeding. Furthermore, this agreement applies only to the DAHRTP-CEV and A.20-10-011 and has no effect, does not restrict, and sets no precedent on any position that the Joint Stipulating Parties will or may take in any other proceeding, including any that address or will address real time pricing or dynamic rate options.

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_007-Q01-Q03		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_007-Q01-Q03Rev01		
Request Date:	May 24, 2021	Requester DR No.:	005
Date Sent:	June 30, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Tysen Streib	Requester:	Jennifer Weberski

UPDATED JUNE 28, 2021

After discussions with SBUA, PG&E identified a few errors in the responses to DR SBUA_007:

- The settlement rate designs for B-6, B-19 Option R, and B-20 Option R were incorrectly applied
- The Marginal Generation Capacity Cost for the CLECA scenarios used CLECA's opening testimony value of $274.64/kW-yr instead of their revised position of $170.43/kW-yr.

These changes affect all four attachments but none of the text answers.

QUESTION 01

If any GRC Phase 2 final settlement agreements would result in material changes since JointParties_001, please update JointParties_001. If it is the judgement of PG&E that there would be immaterial changes, please provide a brief explanation.

ANSWER 01

Please see the attachments "GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch01.xlsx", "GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch02.xlsx", and "GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch03.xlsx".

QUESTION 02

Please provide the same reports provided in response to JointParties_001-Q02 andQ03 for the following rates:

- BEV-1 and BEV-2
- B-1-STOR
- B-6

ANSWER 02

The data provided in attachments "GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch01.xlsx", "GRC-2020-PhII_DR_SBUA_007-Q01Rev01Atch02.xlsx", and "GRC-2020-PhII_DR_SBUA_007-Q01 Rev01Atch03.xlsx" include these additional schedules.

QUESTION 03

Please provide the same report as JointParties_001-Q03, except using the same RTP rate design as used in JointParties_001-Q02 (i.e., rather than energy-only, energy and capacity) for schedules B-1, B-10, B-19, B-20, BEV-1, BEV-2, B-1-STOR, and B-6.

ANSWER 03

Please see the attachment "GRC-2020-PhII_DR_SBUA_007-Q03Rev01Atch01.xlsx".

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E-TOU-C (Tiered)

	PRESENT RATES (May 1, 2020)							PROPOSED RATES							
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)															
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13556	.14266	.04327	.01362	.04628	.05196	.43335	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11556	.07922	.04327	.01362	.04628	.05196	.34991	
Baseline Credit				(.08633)		(.08633)						(.08615)		(.08615)	
WINTER ENERGY CHARGE ($/kWh)															
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08596	.07662	.04327	.01362	.04628	.05196	.31770	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08264	.05159	.04327	.01362	.04628	.05196	.28935	
Baseline Credit				(.08633)		(.08633)						(.08615)		(.08615)	
MINIMUM CHARGE															
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02232		.00166	.32854	10.00
(/kWh)					.05160								.05160		

* Calculated residually as total less sum of other charges. * Calculated residually as total less sum of other charges.

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
B-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.09740	.13589	.04107	.01233	.04218	.32888	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09740	.08666	.04107	.01233	.04218	.27965	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09740	.06585	.04107	.01233	.04218	.25884	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.07723	.08064	.04107	.01233	.04218	.25346	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07723	.06452	.04107	.01233	.04218	.23734	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07723	.04810	.04107	.01233	.04218	.22092	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B1-STORAGE (B1-STORAGE IS NOT CURRENTLY AVAILABLE: RATES ARE ESTIMATED)

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Summer	3.64				3.64		3.73					3.73	
Winter	3.64				3.64		3.73					3.73	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.15795	.18216	.01299	.04218	.39528		.15941	.14069	.04107	.01233	.04218	.39568	
Part-Peak	.05911	.13970	.01299	.04218	.25398		.06057	.09823	.04107	.01233	.04218	.25438	
Off-Peak	.04753	.10395	.01299	.04218	.20665		.04899	.06248	.04107	.01233	.04218	.20705	
Winter													
Peak	.11058	.13158	.01299	.04218	.29733		.11204	.09011	.04107	.01233	.04218	.29773	
Part-Peak	.09342	.11924	.01299	.04218	.26783		.09488	.07777	.04107	.01233	.04218	.26823	
Off-Peak	.02637	.09724	.01299	.04218	.17878		.02783	.05577	.04107	.01233	.04218	.17918	
Super Off-Peak	.02637	.08082	.01299	.04218	.16236		.02783	.03935	.04107	.01233	.04218	.16276	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B-6

	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
ENERGY CHARGE (/kWh)											
Summer											
Peak	.12429	.18197	.01194	.04218	.36038	.15456	.23221	.04107	.01233	.04218	.48235
Off-Peak	.07751	.11081	.01194	.04218	.24244	.08820	.05918	.04107	.01233	.04218	.24295
Winter											
Peak	.08020	.11845	.01194	.04218	.25277	.07586	.09235	.04107	.01233	.04218	.26378
Off-Peak	.07751	.10139	.01194	.04218	.23302	.07297	.05163	.04107	.01233	.04218	.22018
Super Off-Peak	.07751	.08498	.01194	.04218	.21661	.07297	.01555	.04107	.01233	.04218	.18410

	PRESENT RATES (May 1, 2020)				PROPOSED RATES		
CUSTOMER CHARGE (/meter/day)							
Single-phase	.32854	.32854	10.00	.32854		.32854	10.00
Polyphase	.82136	.82136	25.00	.82136		.82136	25.00

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B-10

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.85				8.84	13.69	
Winter	4.75			8.84	13.59		4.85				8.84	13.69	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04609	.15735	.04189	.01218	.01474	.27225	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04609	.09566	.04189	.01218	.01474	.21056	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04609	.06309	.04189	.01218	.01474	.17799	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02786	.09930	.04189	.01218	.01474	.19597	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02786	.06382	.04189	.01218	.01474	.16049	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02786	.02748	.04189	.01218	.01474	.12415	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.87641					4.87641	148.43

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B-19 Secondary

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.09	14.76				24.84	
Part-Peak	3.13	2.17			5.30		2.90	2.15				5.05	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00	1.77			1.77		.00	1.75				1.75	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.52					2.52	
Part-Peak	.78				.78		.73					.73	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.09763	.03965	.01390	.01466	.16583	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.06816	.03965	.01390	.01466	.13636	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.04732	.03965	.01390	.01466	.11552	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.07868	.03965	.01390	.01466	.14688	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.04727	.03965	.01390	.01466	.11547	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00513	.03965	.01390	.01466	.07333	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.06952	.22371	.03965	.01390	.01466	.36143	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02477	.08961	.03965	.01390	.01466	.18258	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00441	.05152	.03965	.01390	.01466	.12414	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09308	.03965	.01390	.01466	.16128	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05148	.03965	.01390	.01466	.11969	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01641	.03965	.01390	.01466	.08461	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	24.10403					24.10403	733.67
Rate V	4.77841				4.77841	145.44	4.87641					4.87641	148.43
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

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B-20 Secondary

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	11.13	14.61			25.74		9.66	14.45				24.11	
Part-Peak	3.19	2.12			5.31		2.77	2.10				4.87	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
Winter													
Peak	.00	1.86			1.86		.00	1.84				1.84	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.78	.00			2.78		2.41					2.41	
Part-Peak	.80	.00			.80		.69					.69	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.09285	.03807	.01260	.01413	.15765	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.06623	.03807	.01260	.01413	.13102	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.04520	.03807	.01260	.01413	.11000	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.07675	.03807	.01260	.01413	.14155	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.04506	.03807	.01260	.01413	.10986	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00261	.03807	.01260	.01413	.06741	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.06555	.21760	.03807	.01260	.01413	.34794	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02205	.08627	.03807	.01260	.01413	.17312	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00332	.04921	.03807	.01260	.01413	.11732	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09211	.03807	.01260	.01413	.15690	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04911	.03807	.01260	.01413	.11391	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01410	.03807	.01260	.01413	.07889	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	43.47022					43.47022	1323.12
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer Max Peak Period	6.17	12.52			18.69		6.06	12.75				18.81	
Summer Max Part-Peak Period					.00		.00	.00				.00	
Summer Maximum	11.21				11.21		11.01	.00				11.01	
Winter Max Peak Period					.00		.00	.00				.00	
Winter Maximum	11.21				11.21		11.01	.00				11.01	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.02005	.11604	.01135	.03624	.18368		.02226	.07912	.03850	.01398	.03625	.19010	
Part-Peak													
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01230	.04964	.03850	.01398	.03625	.15066	
Winter													
Peak	.00690	.10140	.01135	.03624	.15589		.00911	.06448	.03850	.01398	.03625	.16231	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894	.03896	.03850	.01398	.03625	.13662	
Super Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894	.03896	.03850	.01398	.03625	.13662	
CUSTOMER CHARGE (/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63
BEV1	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	

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E-TOU-C (Tiered)

PRESENT RATES (May 1, 2020)

	Distr	Gen	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)							
Peak	.12767	.16735	.01296	.05339	.05196	.41333	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989	
Baseline Credit				(.08633)		(.08633)	
WINTER ENERGY CHARGE ($/kWh)							
Peak	.07935	.11859	.01296	.05338	.05196	.31624	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891	
Baseline Credit				(.08633)		(.08633)	
MINIMUM CHARGE							
(/meter/day)	*		.02123		.00166	.32854	10.00
(/kWh)					.05160		

* Calculated residually as total less sum of other charges.

PROPOSED RATES

	Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)								
Peak	.13556	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972	.04327	.01362	.04628	.05196	.29069	
Off-Peak	.11556		.04327	.01362	.04628	.05196	.27069	
Baseline Credit					(.08615)		(.08633)	
WINTER ENERGY CHARGE ($/kWh)								
Peak	.08596		.04327	.01362	.04628	.05196	.24109	
Off-Peak	.08264		.04327	.01362	.04628	.05196	.23777	
Baseline Credit					(.08615)		(.08633)	
MINIMUM CHARGE								
(/meter/day)	*			.02232		.00166	.02398	10.00
(/kWh)						.05160		

* Calculated residually as total less sum of other charges.

B-1

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.09740	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972	.04107	.01233	.04218	.19298	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09740		.04107	.01233	.04218	.19298	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09740		.04107	.01233	.04218	.19298	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.07723		.04107	.01233	.04218	.17281	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07723		.04107	.01233	.04218	.17281	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07723		.04107	.01233	.04218	.17281	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B1-STORAGE

(B1-STORAGE IS NOT CURRENTLY AVAILABLE: RATES ARE ESTIMATED)

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Summer	3.64				3.64		3.73					3.73	
Winter	3.64				3.64		3.73					3.73	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.15795	.18216	.01299	.04218	.39528		.15941	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972	.04107	.01233	.04218	.25499	
Part-Peak	.05911	.13970	.01299	.04218	.25398		.06057		.04107	.01233	.04218	.15615	
Off-Peak	.04753	.10395	.01299	.04218	.20665		.04899		.04107	.01233	.04218	.14457	
Winter													
Peak	.11058	.13158	.01299	.04218	.29733		.11204		.04107	.01233	.04218	.20762	
Part-Peak	.09342	.11924	.01299	.04218	.26783		.09488		.04107	.01233	.04218	.19046	
Off-Peak	.02637	.09724	.01299	.04218	.17878		.02783		.04107	.01233	.04218	.12341	
Super Off-Peak	.02637	.08082	.01299	.04218	.16236		.02783		.04107	.01233	.04218	.12341	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B-6

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.12429	.18197	.01194	.04218	.36038		.15456	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972	.04107	.01233	.04218	.25014	
Off-Peak	.07751	.11081	.01194	.04218	.24244		.08820		.04107	.01233	.04218	.18378	
Winter													
Peak	.08020	.11845	.01194	.04218	.25277		.07586		.04107	.01233	.04218	.17144	
Off-Peak	.07751	.10139	.01194	.04218	.23302		.07297		.04107	.01233	.04218	.16855	
Super Off-Peak	.07751	.08498	.01194	.04218	.21661		.07297		.04107	.01233	.04218	.16855	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B-10	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.85				8.84	13.69	
Winter	4.75			8.84	13.59		4.85				8.84	13.69	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04609	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972	.04189	.01218	.01474	.11490	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04609		.04189	.01218	.01474	.11490	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04609		.04189	.01218	.01474	.11490	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02786		.04189	.01218	.01474	.09667	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02786		.04189	.01218	.01474	.09667	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02786		.04189	.01218	.01474	.09667	
CUSTOMER CHARGE													
(/meter/day)	4.77841				4.77841	145.44	4.87641					4.87641	148.68

B-19 Secondary

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.09					10.09	
Part-Peak	3.13	2.17			5.30		2.90					2.90	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.52					2.52	
Part-Peak	.78				.78		.73					.73	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		12.33	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972			8.91	21.25	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000		.03965	.01390	.01466	.06820	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01390	.01466	.06820	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01390	.01466	.06820	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01390	.01466	.06820	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.06952		.03965	.01390	.01466	.13772	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02477		.03965	.01390	.01466	.09297	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00441		.03965	.01390	.01466	.07261	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01390	.01466	.06820	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01390	.01466	.06820	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	24.10403					24.10403	730.09
Rate V	4.77841				4.77841	145.44	4.87641					4.87641	148.68
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)												
Summer												
Peak	11.13	14.61			25.74		9.66					9.66
Part-Peak	3.19	2.12			5.31		2.77					2.77
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45
Winter												
Peak	.00	1.86			1.86		.00					.00

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.78	.00			2.78		2.41					2.41	
Part-Peak	.80	.00			.80		.69					.69	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		11.71	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972				21.45	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000		.03807	.01260	.01413	.06480	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01260	.01413	.06480	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01260	.01413	.06480	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01260	.01413	.06480	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.06555		.03807	.01260	.01413	.13034	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02205		.03807	.01260	.01413	.08685	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00332		.03807	.01260	.01413	.06811	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01260	.01413	.06480	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01260	.01413	.06480	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	43.47022					43.47022	1301.17
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

AG-C	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGE (/kW)											
Secondary											
Summer Max Peak Period	6.17	12.52			18.69	6.06					6.06
Summer Max Part-Peak Period					.00	.00					.00
Summer Maximum	11.21				11.21	11.01					11.01
Winter Max Peak Period					.00	.00					.00
Winter Maximum	11.21				11.21	11.01	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01972				11.01
ENERGY CHARGE (/kWh)											
Summer											
Peak	.02005	.11604	.01135	.03624	.18368	.02226		.03850	.01398	.03625	.11099
Part-Peak											
Off-Peak	.01009	.08656	.01135	.03624	.14424	.01230		.03850	.01398	.03625	.10103
Winter											

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
Peak	.00690	.10140	.01135	.03624	.15589		.00911		.03850	.01398	.03625	.09784	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894		.03850	.01398	.03625	.09767	
Super Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894		.03850	.01398	.03625	.09767	
CUSTOMER CHARGE (/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	.00
BEV1	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	

PRESENT RATES (May 1, 2020) | **PROPOSED RATES**

E-TOU-C (Tiered)

	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	RTP	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)																
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13556	(.02429)	.04327	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01362	.04628	.05196	.26640	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11556	.03761	.04327		.01362	.04628	.05196	.30830	
Baseline Credit				(.08633)		(.08633)							(.08615)		(.08615)	
WINTER ENERGY CHARGE ($/kWh)																
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08596	.01097	.04327		.01362	.04628	.05196	.25205	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08264	.02169	.04327		.01362	.04628	.05196	.25946	
Baseline Credit				(.08633)		(.08633)							(.08615)		(.08615)	
MINIMUM CHARGE																
(/meter/day)	*		.02123		.00166	.32854	10.00	*				.02232		.00166	.32854	10.00
(/kWh)					.05160									.05160		

* Calculated residually as total less sum of other charges.

* Calculated residuall Calculated residually as total less sum of other charges.

	PRESENT RATES (May 1, 2020)						PROPOSED RATES							
B-1	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
ENERGY CHARGE (/kWh)														
Summer														
Peak	.09551	.17737	.01299	.04218	.32805		.09740	(.01835)	.04107	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01233	.04218	.17463	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09740	.02773	.04107		.01233	.04218	.22072	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09740	.03808	.04107		.01233	.04218	.23106	
Winter														
Peak	.07534	.12212	.01299	.04218	.25263		.07723	.01817	.04107		.01233	.04218	.19098	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07723	.03366	.04107		.01233	.04218	.20648	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07723	.04825	.04107		.01233	.04218	.22106	
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00

B1-STORAGE (B1-STORAGE IS NOT CURRENTLY AVAILABLE: RATES ARE ESTIMATED)

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
DEMAND CHARGE (/kW)														
Summer	3.64				3.64		3.73						3.73	
Winter	3.64				3.64		3.73						3.73	
ENERGY CHARGE (/kWh)														
Summer														
Peak	.15795	.18216	.01299	.04218	.39528		.15941	(.01356)	.04107	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01233	.04218	.24143	
Part-Peak	.05911	.13970	.01299	.04218	.25398		.06057	.03930	.04107		.01233	.04218	.19545	
Off-Peak	.04753	.10395	.01299	.04218	.20665		.04899	.03471	.04107		.01233	.04218	.17928	
Winter														
Peak	.11058	.13158	.01299	.04218	.29733		.11204	.02763	.04107		.01233	.04218	.23525	
Part-Peak	.09342	.11924	.01299	.04218	.26783		.09488	.03908	.04107		.01233	.04218	.22954	
Off-Peak	.02637	.09724	.01299	.04218	.17878		.02783	.03941	.04107		.01233	.04218	.16282	
Super Off-Peak	.02637	.08082	.01299	.04218	.16236		.02783	.03950	.04107		.01233	.04218	.16291	
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00

B-6

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
ENERGY CHARGE (/kWh)														
Summer														
Peak	.12429	.18197	.01194	.04218	.36038		.15456	(.02485)	.04107	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01233	.04218	.22529	
Off-Peak	.07751	.11081	.01194	.04218	.24244		.08820	(.00179)	.04107		.01233	.04218	.18199	
Winter														
Peak	.08020	.11845	.01194	.04218	.25277		.07586	.01009	.04107		.01233	.04218	.18153	
Off-Peak	.07751	.10139	.01194	.04218	.23302		.07297	.00309	.04107		.01233	.04218	.17164	
Super Off-Peak	.07751	.08498	.01194	.04218	.21661		.07297	.04947	.04107		.01233	.04218	.21803	
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00

B-10

	PRESENT RATES (May 1, 2020)						PROPOSED RATES							
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
DEMAND CHARGE (/kW)														
Secondary														
Summer	4.75			8.84	13.59		4.85					8.84	13.69	
Winter	4.75			8.84	13.59		4.85					8.84	13.69	
ENERGY CHARGE (/kWh)														
Secondary														
Summer														
Peak	.04539	.20191	.01205	.01474	.27409		.04609	.00290	.04189	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01218	.01474	.11780	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04609	.03650	.04189		.01218	.01474	.15140	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04609	.03520	.04189		.01218	.01474	.15010	
Winter														
Peak	.02716	.14386	.01205	.01474	.19781		.02786	.03708	.04189		.01218	.01474	.13375	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02786	.03301	.04189		.01218	.01474	.12968	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02786	.02748	.04189		.01218	.01474	.12415	
CUSTOMER CHARGE														
(/meter/day)	4.77841				4.77841	145.44	4.87641						4.87641	148.43

B-19 Secondary

	PRESENT RATES (May 1, 2020)						PROPOSED RATES							
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
DEMAND CHARGES (/kW)														
Summer														
Peak	10.87	14.92			25.79		10.09	14.76					24.84	
Part-Peak	3.13	2.17			5.30		2.90	2.15					5.05	
Maximum	12.53			8.91	21.44		12.33					8.91	21.25	
Winter														
Peak	.00	1.77			1.77		.00	1.75					1.75	
Maximum	12.53			8.91	21.44		12.33					8.91	21.25	
DEMAND CHARGES - OPTION R ($/kW)														
Summer														
Peak	2.72				2.72		2.52						2.52	
Part-Peak	.78				.78		.73						.73	
Maximum	12.53			8.91	21.44		12.33					8.91	21.25	
Winter														
Peak	.00						.00						.00	
Maximum	12.53			8.91	21.44		12.33			Generation is an RTP rate made up of:		8.91	21.25	
										1) CAISO market price plus line losses				
ENERGY CHARGES (/kWh)										2) Capacity adder as determined by the				
Summer										capacity equation and a capacity price of				
Peak	.00000	.13878	.01177	.01465	.16520		.00000	(.06963)	.03965	$68.56/kW-yr	.01390	.01466	(.00143)	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.00396	.03965		.01390	.01466	.07216	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.01838	.03965		.01390	.01466	.08658	
Winter														
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.01533	.03965		.01390	.01466	.08353	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.01537	.03965		.01390	.01466	.08357	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00525	.03965		.01390	.01466	.07345	
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07499	.26625	.01177	.01465	.36766		.06952	.05645	.03965		.01390	.01466	.19417	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02477	.02541	.03965		.01390	.01466	.11838	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00441	.02259	.03965		.01390	.01466	.09520	
Winter														
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.02973	.03965		.01390	.01466	.09793	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.01959	.03965		.01390	.01466	.08779	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01652	.03965		.01390	.01466	.08472	
CUSTOMER CHARGE (/meter/day)														
B-19	24.77594				24.77594	754.12	24.10403						24.10403	733.67
Rate V	4.77841				4.77841	145.44	4.87641						4.87641	148.43
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005						.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-20 Secondary

	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	RTP	PPP	Other	Total
DEMAND CHARGES (/kW)												
Summer												
Peak	11.13	14.61			25.74	9.66	14.45					24.11
Part-Peak	3.19	2.12			5.31	2.77	2.10					4.87
Maximum	11.66	.00		9.75	21.41	11.71	.00				9.74	21.45
Winter												
Peak	.00	1.86			1.86	.00	1.84					1.84
Maximum	11.66	.00		9.75	21.41	11.71	.00				9.74	21.45

DEMAND CHARGES - OPTION R ($/kW)

	PRESENT RATES (May 1, 2020)						PROPOSED RATES							
Summer														
Peak	2.78	.00			2.78		2.41	.00					2.41	
Part-Peak	.80	.00			.80		.69	.00					.69	
Maximum	11.66	.00		9.75	21.41		11.71	.00				9.74	21.45	
Winter														
Peak	.00	.00			.00		.00	.00					.00	
Maximum	11.66	.00		9.75	21.41		11.71	.00				9.74	21.45	
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13233	.01146	.01413	.15792		.00000	(.06795)	.03807	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr	.01260	.01413	(.00315)	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.00383	.03807		.01260	.01413	.06862	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.01624	.03807		.01260	.01413	.08104	
Winter														
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.01465	.03807		.01260	.01413	.07945	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.01335	.03807		.01260	.01413	.07815	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00268	.03807		.01260	.01413	.06747	
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07547	.25843	.01146	.01413	.35949		.06555	.05680	.03807		.01260	.01413	.18714	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02205	.02387	.03807		.01260	.01413	.11072	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00332	.02025	.03807		.01260	.01413	.08836	
Winter														
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.03001	.03807		.01260	.01413	.09480	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.01740	.03807		.01260	.01413	.08219	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01416	.03807		.01260	.01413	.07896	
CUSTOMER CHARGE (/meter/day)	45.08771				45.08771	1372.36	43.47022						43.47022	1323.12
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005						.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total	
DEMAND CHARGE (/kW)														
Secondary														
Summer Max Peak Period	6.17	12.52			18.69		6.06	12.75					18.81	
Summer Max Part-Peak Period					.00		.00						.00	
Summer Maximum	11.21				11.21		11.01						11.01	
Winter Max Peak Period					.00		.00						.00	
Winter Maximum	11.21				11.21		11.01			Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr			11.01	
ENERGY CHARGE (/kWh)														
Summer														
Peak	.02005	.11604	.01135	.03624	.18368		.02226	(.03814)	.03850		.01398	.03625	.07284	
Part-Peak														
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01230	(.01268)	.03850		.01398	.03625	.08835	
Winter														
Peak	.00690	.10140	.01135	.03624	.15589		.00911	.00016	.03850		.01398	.03625	.09800	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894	.00224	.03850		.01398	.03625	.09991	
							.00894							
(/meter/day)	1.43343				1.43343	43.63	1.43343					.00000	1.43343	43.63

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_008-Q02		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_008-Q02		
Request Date:	July 1, 2021	Requester DR No.:	008
Date Sent:	July 14, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Tysen Streib	Requester:	Jennifer Weberski

QUESTION 02

Please provide the same report as SBUA_007-Q01Atch2, however in place of the uniform, system average Revenue Neutral Rate Adder (as originally specified in JointParties_001-Q02), please substitute a uniform, rate-specific Revenue Neutral Rate Adder.

ANSWER 02

Please see attachment “GRC-2020-PhII_DR_SBUA_008-Q02Atch01.xlsx”.

E-TOU-C (Tiered)

PRESENT RATES (May 1, 2020)

E-TOU-C (Tiered)	Distr	Gen	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)							
Peak	.12767	.16735	.01296	.05339	.05196	.41333	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989	
Baseline Credit				(.08633)		(.08633)	
WINTER ENERGY CHARGE ($/kWh)							
Peak	.07935	.11859	.01296	.05338	.05196	.31624	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891	
Baseline Credit				(.08633)		(.08633)	
MINIMUM CHARGE							
(/meter/day)	*		.02123		.00166	.32854	10.00
(/kWh)					.05160		

* Calculated residually as total less sum of other charges.

PROPOSED RATES

E-TOU-C (Tiered)	Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)								
Peak	.13556	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01824	.04327	.01362	.04628	.05196	.29069	
Off-Peak	.11556		.04327	.01362	.04628	.05196	.27069	
Baseline Credit					(.08615)		(.08633)	
WINTER ENERGY CHARGE ($/kWh)								
Peak	.08596		.04327	.01362	.04628	.05196	.24109	
Off-Peak	.08264		.04327	.01362	.04628	.05196	.23777	
Baseline Credit					(.08615)		(.08633)	
MINIMUM CHARGE								
(/meter/day)	*			.02232		.00166	.02398	10.00
(/kWh)						.05160		

* Calculated residually as total less sum of other charges.

B-1

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.09740	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.02809	.04107	.01233	.04218	.19298	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09740		.04107	.01233	.04218	.19298	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09740		.04107	.01233	.04218	.19298	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.07723		.04107	.01233	.04218	.17281	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07723		.04107	.01233	.04218	.17281	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07723		.04107	.01233	.04218	.17281	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B1-STORAGE

(B1-STORAGE IS NOT CURRENTLY AVAILABLE: RATES ARE ESTIMATED)

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Summer	3.64				3.64		3.73					3.73	
Winter	3.64				3.64		3.73					3.73	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.15795	.18216	.01299	.04218	.39528		.15941	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.02809	.04107	.01233	.04218	.25499	
Part-Peak	.05911	.13970	.01299	.04218	.25398		.06057		.04107	.01233	.04218	.15615	
Off-Peak	.04753	.10395	.01299	.04218	.20665		.04899		.04107	.01233	.04218	.14457	
Winter													
Peak	.11058	.13158	.01299	.04218	.29733		.11204		.04107	.01233	.04218	.20762	
Part-Peak	.09342	.11924	.01299	.04218	.26783		.09488		.04107	.01233	.04218	.19046	
Off-Peak	.02637	.09724	.01299	.04218	.17878		.02783		.04107	.01233	.04218	.12341	
Super Off-Peak	.02637	.08082	.01299	.04218	.16236		.02783		.04107	.01233	.04218	.12341	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B-6

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.12429	.18197	.01194	.04218	.36038		.15456	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.00043	.04107	.01233	.04218	.25014	
Off-Peak	.07751	.11081	.01194	.04218	.24244		.08820		.04107	.01233	.04218	.18378	
Winter													
Peak	.08020	.11845	.01194	.04218	.25277		.07586		.04107	.01233	.04218	.17144	
Off-Peak	.07751	.10139	.01194	.04218	.23302		.07297		.04107	.01233	.04218	.16855	
Super Off-Peak	.07751	.08498	.01194	.04218	.21661		.07297		.04107	.01233	.04218	.16855	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

B-10	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.85				8.84	13.69	
Winter	4.75			8.84	13.59		4.85				8.84	13.69	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04609	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.03134	.04189	.01218	.01474	.11490	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04609		.04189	.01218	.01474	.11490	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04609		.04189	.01218	.01474	.11490	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02786		.04189	.01218	.01474	.09667	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02786		.04189	.01218	.01474	.09667	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02786		.04189	.01218	.01474	.09667	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.87641					4.87641	148.68

B-19 Secondary

B-19 Secondary	PRESENT RATES (May 1, 2020) Distr	Gen	PPP	Other	Total		PROPOSED RATES Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.09					10.09	
Part-Peak	3.13	2.17			5.30		2.90					2.90	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.52					2.52	
Part-Peak	.78				.78		.73					.73	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		12.33				8.91	21.25	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000		.03965	.01390	.01466	.06820	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01390	.01466	.06820	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01390	.01466	.06820	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01390	.01466	.06820	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.06952		.03965	.01390	.01466	.13772	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02477		.03965	.01390	.01466	.09297	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00441		.03965	.01390	.01466	.07261	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01390	.01466	.06820	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01390	.01466	.06820	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01390	.01466	.06820	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	24.10403					24.10403	730.09
Rate V	4.77841				4.77841	145.44	4.87641					4.87641	148.68
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

Generation is an RTP rate made up of:
1) CAISO market price plus line losses
2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr
3) A flat adder of $0.00782 (standard rate) or $0.02491 (Option R)

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

B-20 Secondary

B-20 Secondary	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)											
Summer											
Peak	11.13	14.61			25.74	9.66					9.66
Part-Peak	3.19	2.12			5.31	2.77					2.77
Maximum	11.66	.00		9.75	21.41	11.71				9.74	21.45
Winter											
Peak	.00	1.86			1.86	.00					.00

	PRESENT RATES (May 1, 2020)						PROPOSED RATES						
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.78	.00			2.78		2.41					2.41	
Part-Peak	.80	.00			.80		.69					.69	
Maximum	11.66	.00		9.75	21.41		11.71				9.74	21.45	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		11.71	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.00696 (standard rate) or $0.02291 (Option R)			9.74	21.45	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000		.03807	.01260	.01413	.06480	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01260	.01413	.06480	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01260	.01413	.06480	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01260	.01413	.06480	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.06555		.03807	.01260	.01413	.13034	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02205		.03807	.01260	.01413	.08685	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00332		.03807	.01260	.01413	.06811	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01260	.01413	.06480	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01260	.01413	.06480	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01260	.01413	.06480	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	43.47022					43.47022	1301.17
POWER FACTOR ADJUSTMENT (/kWh)	.00005				.00005		.00005					.00005	

per kWh charge or credit to be applicable per each 1% deviation above or below standard power factor of 85%

AG-C	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGE (/kW)											
Secondary											
Summer Max Peak Period	6.17	12.52			18.69	6.06					6.06
Summer Max Part-Peak Period					.00	.00					.00
Summer Maximum	11.21				11.21	11.01					11.01
Winter Max Peak Period					.00	.00					.00
Winter Maximum	11.21				11.21	11.01	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $(0.00760)				11.01
ENERGY CHARGE (/kWh)											
Summer											
Peak	.02005	.11604	.01135	.03624	.18368	.02226		.03850	.01398	.03625	.11099
Part-Peak											
Off-Peak	.01009	.08656	.01135	.03624	.14424	.01230		.03850	.01398	.03625	.10103
Winter											

	PRESENT RATES (May 1, 2020)						**PROPOSED RATES**						
Peak	.00690	.10140	.01135	.03624	.15589		.00911		.03850	.01398	.03625	.09784	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894		.03850	.01398	.03625	.09767	
Super Off-Peak	.00673	.07588	.01135	.03624	.13020		.00894		.03850	.01398	.03625	.09767	
CUSTOMER CHARGE (/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	.00
BEV1	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	