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

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

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ATTACHMENTS

Attachment 1	*CAISO Event Data*
Attachment 2	*PG&E, Response to SBUA Data Request 005-Q01, A.19-11-019 (Attachments omitted due to length.)*
Attachment 3	*PG&E, Response to SBUA Data Request 004-Q01, A.19-11-019 (Attachments omitted due to length.)*

I. Introduction

Q: Are you the same Paul Chernick and John D. Wilson who filed direct and reply testimony in this proceeding?

A: Yes.

Q: What is the scope of your responsive testimony?

A: We respond to the supplemental testimony filed by PG&E on RTP issues and comment on proposals made by Cal Advocates and Enel X in the A.20-10-11, PG&E's Application for a Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot (DAHRTP-CEV pilot).

Q: What issues do you address?

A: Our testimony updates our recommendations for RTP rates based on PG&E's supplemental testimony and on further research we have conducted and filed in A.20-10-11 (DAHRTP-CEV pilot). We address the following topics:

Section II Scope and Timing of RTP Rates

- Interest of small businesses
- Modifications to include small businesses
- Modifications to enrollment rules
- Risk of price volatility
- Areas of support / do not contest

Section III Overview of Response to RTP Rate Design

- Support for PG&E MECs
- Overview of MGCC proposal
- Overview of revenue-neutral TOU adder

Section IV Issues with PG&E's ANL/PCAF Method

- Relationship between ANL, PCAF, and reliability metrics (LOLE, EUE, and CAISO AWE events)

Section V Issues with Cal Advocates' CPP Method

- Issues with CPP rate design proposal

Section VI SBUA Proposal for Hourly Marginal Generation Capacity Cost Rates

- ANL/PCAF, Flex Alert, and RMO components
- Comparison with PG&E and Cal Advocates

Section VII Design of the Revenue Neutral Adder

- Issues with flat revenue neutral rate adder
- Importance of maintaining time-differentiated rates for consistency with the otherwise applicable tariff

Q: Please provide a brief summary of your recommendations.

A: We recommend the Commission direct PG&E to:

1. Extend the proposed C&I RTP Pilot to include rate schedules applicable to customers of all sizes;
2. Primarily rely on third-party product and service providers for recruitment of small business participants, as recommended by JARP;
3. Allow participants to remain on the RTP tariff, rather than being automatically transitioned back to the Otherwise Applicable Tariff (OAT);
4. File Advice Letters recommending immediate changes to or termination of the RTP rates, as discussed in our testimony above;

5. Clarify that customers will be permitted to enroll in the RTP rate at any time that it is available as a rate option;
6. Proceed with a study of the relationship of ANL and reliability metrics, as suggested by SBUA in A.20-10-011 and supported by PG&E;
7. Adopt SBUA's proposal to price MGCC costs using a combination of PG&E's ANL/PCAF method and CAISO event adders triggered by Flex Alert and RMO events; and
8. Utilize a time-differentiated revenue-neutral rate adder, or its equivalent, to collect revenues other than the MECs, MGCCs, PCIA and RECs, as proposed by SBUA and Enel X.

II. Scope and Timing of RTP Rates

Q: Please summarize PG&E's supplemental RTP rate proposal.

A: PG&E proposes a C&I RTP Pilot, rate design and preference research for residential customers, and research into an agricultural rate structure similar to SCE's RTP rate.

SBUA is not commenting on the residential and agricultural rate options, except to note that many small businesses have loads and other characteristics that are similar to residential customers. To the extent that the Commission determines that residential customers should be offered RTP rates and incudes features (e.g., submetering) that differ from the C&I RTP Pilot, we recommend that the Commission also evaluate whether those features should also be made available to small businesses.

PG&E's proposed C&I RTP Pilot would be open to all C&I customers, but would be targeted to its 9,000 bundled customers with peak demands over

100 kW, by requiring customers to utilize the TOU B-19 and B-20 rates designed for medium and large customers. The rate would also be particularly focused on approximately 1,000 bundled customers who have an energy manager on staff and/or have an automated energy management system in place.[1] PG&E also proposes to encourage no more than two Community Choice Aggregators (CCAs) or Energy Service Providers (ESPs) to participate, also targeting large C&I customers.[2] At the conclusion of the pilot, customers would be transitioned back to their Otherwise Applicable Tariff (OAT).[3]

Q: What evidence or reasoning does PG&E offer to explain why small businesses are entirely excluded from its proposal?

A: PG&E provides the following lines of evidence and argument:

- A 2010 study that PG&E describes as finding that "large C&I customers are likely to be better equipped to respond to price signals and take advantage of DR programs and more dynamic rate plans."[4]
- A 2016 study that PG&E says found that "customers with greater demand size correspondingly had greater proportional average customer load impact on events."[5]

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[1] PG&E Supplemental RTP Testimony, Ch. 5, p. 2, lines 25-27; p. 7, Table 5-2; p. 12, lines 14-19.

[2] PG&E Supplemental RTP Testimony, Ch. 5, p. 11, Table 5-3.

[3] PG&E Supplemental RTP Testimony, Ch. 5, p. 8, lines 11-13.

[4] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 5-8; p. 13, lines 4-7.

[5] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 9-11.

- Assessing "whether a customer could likely benefit on RTP is challenging because assumptions need to be made about how the customer might respond to the new RTP price signal."[6]
- Evidence from RTP rate schedules offered by SCE and other regulated US utilities indicates that large C&I customers will enroll in and can benefit from RTP rates.[7]
- The claim that "to effectively enroll participants … PG&E will need to clearly explain to targeted customers the potential benefits and risks for them of an RTP rate and what they would need to be able to do to succeed on it" and thus that the "Prime target audience for focused initial outreach is customers who already have an energy manager and/or equipment that automates a business's ability to respond."[8]

Some of these points are hardly surprising: larger customers will be able to shift more load per customer in response to RTP, and larger customers are more likely to have staff dedicated to managing energy use. Those realities do not justify ignoring the potential for small businesses to participate in RTP, any more than similar considerations justify excluding small businesses from energy-efficiency programs.

Q: Is PG&E's evidence and reasoning for excluding small businesses from its proposal persuasive?

A: No. Since the 2010 and 2016 studies cited by PG&E, small businesses and their managers have gained substantial experience with CPP and TOU rates.

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[6] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 24-27.

[7] PG&E Supplemental RTP Testimony, Ch.2, p. 15, lines 8-10; p. 18, lines 8-11; p. 36, lines 10-13.

[8] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 20-24, 27-29.

Many small businesses have automated some or all of their energy management systems, including automated energy management systems and/or battery storage. The growing availability of new technologies, often connected to cloud-based automation, continues to expand opportunities for engaging small business participation in dynamic rates.

The only direct evidence of small business engagement in an RTP rate discussed in PG&E's supplemental RTP testimony is that 20 of 150 C&I participants in SCE's RTP program have demand less than 20 kW.[9] However, as PG&E notes, SCE's program uses a rate design that is very different, with "limited and predictable price volatility since [SCE's rates] do not pass through wholesale prices."[10] It is not clear that this "mild" RTP design provides a sufficient price incentive for small businesses to adopt new technologies.

Perhaps PG&E is unaware of the ability of small businesses to respond to more dynamic rate offers because PG&E has made little effort to engage small businesses on this topic. For example, in its DAHRTP-CEV Pilot application, PG&E featured an EPRI study of rate design and commercial EVs in which none of the 23 "EV stakeholder organizations" included as study participants represented small businesses.[11]

Q: Would an RTP rate be of interest to a small business?

A: We believe that there would be many small businesses that would be interested in an RTP rate. Small or medium-sized business businesses (SMBs) that own their property tend to pay their own electric bills and are likely to be good candidates for a C&I RTP pilot. A survey of SMBs in the nine-county San

[9] PG&E Supplemental RTP Testimony, Ch. 5, p. 18, Table 2-6.

[10] PG&E Supplemental RTP Testimony, Ch. 5, p. 15, lines 16-18.

[11] PG&E, Testimony, A.20-10-011, Ch. 1, Attachment A, pp. 20-21.

Francisco Bay Area found that over three-quarters of them owned, managed, and occupied the entire building.[12] As noted above, approximately 20 small businesses were participating in SCE's RTP rate in 2016.[13] Tech companies would be an obvious target market, considering the likelihood that those companies would be early adopters.

About 10 percent of PG&E customers on small general tariffs have voluntarily adopted rates with greater TOU differentiation than the default tariff.[14] As shown in Table 1, a small number of customers have opted in to the B-1-Storage pilot rate, but a substantial number of customers have opted in to the A-6 and B-6 rate schedules. Compared to the default A-1 and B-1 rate schedules, the optional A-6 and B-6 rate schedules have higher prices on summer weekday afternoons and lower winter and off-peak rates. The 10 percent participation rate in these rates suggests that small businesses are actively seeking opportunities to opt-in to rates that provide them with opportunities to reduce their bills.

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[12] Applied Energy Group, *BayREN SMB Non-Deemed Market Characterization Study*, CALMAC Study ID BAR0001-01 (July 26, 2018), p. 8.

[13] PG&E Supplemental RTP Testimony, Ch. 5, p. 18, Table 2-6.

[14] Although some small businesses are likely served on schedules A10, A10-TOU, and B10, we excluded these schedules from our calculation since these rates primarily serve medium and large businesses.

Table 1: PG&E Small General Customers (November 2020)[15]

Rate Schedule	Number of Customers (Billings)
A-1	57,421
A-1-TOU	292,858
B-1	30,010
Small General Service Default Schedule	**380,289**
A-6	30,010
B-1-Storage	22
B-6	13,168
Small General Service Advanced Schedule	**43,200**
Total	**423,489**

Small businesses are likely to face somewhat different challenges in adopting C&I RTP rates than would larger businesses. For example, small businesses may lack staff with the time, authority and expertise to take the lead on energy management systems. On the other hand, a small business may be able to commit more quickly than a large corporation with multiple levels of review. The actual differences between small and larger businesses should be considered in the pilot.

Q: How should the proposed C&I RTP Pilot be modified to include small business customers?

A: The C&I RTP Pilot should be expanded to include rate schedules applicable to customers of all sizes. Our main recommendation is that all rate schedules be modified to include an RTP Pilot option. If PG&E prefers to restrict the number of rate schedules that are modified to include the RTP Pilot option, then, at a minimum, the advanced B-1-Storage and B-6 rate schedules should

[15] PG&E, response to SBUA_002-Q01 (January 14, 2021).

be included to serve small businesses who have demonstrated an interest in alternative rates.

As PG&E notes, customers who "have an energy manager and/or equipment that automates a business's ability to respond" are more likely to effectively respond to real-time price signals.[16] JARP's testimony describes how third-party providers can engage customers in an RTP pilot by utilizing RTP-enabling technologies to cost-effectively reduce barriers for smaller customers to benefit from dynamic rate options.[17] We agree that small businesses are more likely to acquire those capabilities when supported by off-the-shelf technology or third party expertise (e.g., a battery storage installer).

To help small businesses develop the capability to participate in the C&I RTP Pilot, we support the recruitment approach recommended by the Joint Advanced Rate Parties (JARP), as follows.

> The responsibility for recruiting participants will fall largely on third-party product and service providers in the energy storage, demand response, and electric vehicle charging industries, similar to California Solar Initiative and Self-Generation Incentive Program. At minimum, PG&E should be required to include announcements about the availability of the rate in two or three rounds of billing inserts, separate mailers and/or emails and to create a website with information about the rate, how it works, and potential bill savings. As an additional step, more targeted ME&O would help to stimulate greater participation in the rate. We suggest that the Commission require PG&E to conduct an additional round of outreach to customers with energy storage systems, electric vehicles, or high consumption during peak load periods.[18]

[16] PG&E Supplemental RTP Testimony, Ch. 5, p. 12, lines 20-24, 27-29.

[17] Joint Advanced Rate Parties Direct Testimony, p. 27, line 20 through p. 28, line 12.

[18] Joint Advanced Rate Parties Direct Testimony, p. 28, lines 6-15.

Q: What modifications do you suggest to the enrollment rules for the proposed C&I RTP Pilot?

A: We recommend one modification and one clarification to the enrollment rules. First, at the conclusion of the two-year pilot, customers should be allowed to remain on the RTP tariff, rather than being automatically transitioned back to the Otherwise Applicable Tariff (OAT). PG&E does not provide any reason for this pilot rate treatment other than a need for "time to evaluate the feasibility of the rate plan, and, perhaps, change the rate design."[19]

Ending the pilot rate program has several disadvantages. First, customers will be less likely to invest the human and financial resources to learn about and engage in the C&I RTP pilot if they believe that the benefits will be limited to two years. If they perceive a risk that the payback for the resources invested might extend beyond two years, then they may choose not to enroll, reducing the participant pool and resulting in less significant evaluation results.

Second, if the C&I RTP pilot has significant system benefits, then the investment that PG&E is making on customer's behalf will cease at the end of the two-year pilot. Then, additional resources will be required to re-recruit those same (or alternative) customers if a C&I RTP rate option is re-authorized by the Commission.

Of course, there is the risk that the C&I RTP pilot may appear to have limited or no system benefits, and that continuing it beyond the two-year period may not be in the interests of customers. To reduce this risk, we propose the following:

[19] PG&E Supplemental RTP Testimony, Ch. 5, p. 8, lines 11-16.

- Pilot participants should be alerted that after the two-year period is completed, the RTP rate design may be changed or terminated at any time by order of the Commission;
- After completing the interim evaluation report after the end of the first year, PG&E should be required to file an Advice Letter indicating whether or not it recommends terminating the RTP rates when the pilot ends;
- If other parties wish to protest PG&E's recommendation, they should have the opportunity to submit comments on the Advice Letter; and
- At any later point (such as after completion of the final pilot report), PG&E may file a similar Advice Letter recommending immediate changes to or termination of the RTP pilot, with similar opportunities for parties to comment.

This process will provide PG&E with a reasonable process for minimizing risks of unnecessary expense while avoiding uneconomic stranding of investments in designing and operating the pilot.

The clarification we recommend is to specify that customers will be permitted to enroll in the RTP rate at any time that it is available as a rate option. This is suggested by PG&E's testimony, but not clearly stated.[20] There is not likely to be significant additional cost if a small number of additional participants enroll after the pilot has begun. While it is desirable for customers to enroll for the full two-year pilot for evaluation purposes, useful quantitative

[20] The only reference to mid-Pilot enrollment may be where PG&E states, "customers that may enroll or leave the program partway through the year" when discussing the method for adjusting ERRA rates. PG&E Supplemental RTP Testimony, Ch. 4, p. 5, lines 2-3.

and qualitative data can be obtained from participants who only enroll in a portion of the pilot period. Potentially, if enrolled customers are highly satisfied with the pilot, word-of-mouth may drive further participation—an outcome that would be useful to investigate in the evaluation report.

Q: Are you concerned that small businesses may be exposed to excessive price risks from RTP rates?

A: Not greatly, although we encourage PG&E and third-party providers to educate customers about potential price risks. PG&E provides testimony regarding the experience of residential customers in the ERCOT market during the unprecedented market prices experienced in February 2021.[21] PG&E also provides evidence that CAISO market prices would be less volatile than ERCOT's prices.[22]

We conducted further analysis of price volatility, relying on data provided by PG&E to illustrate its proposal.[23] Our analysis examines two of the most extreme volatility events, the highest hourly energy price on August 19, 2020 and the highest hourly capacity price on September 6, 2020. We evaluated the peak hourly price, peak average daily price, and peak average weekly price for each of these two events.[24]

As shown in Figure 1, while the peak hourly price would have exceeded $1,000 per MWh during some hours, the peak average daily price did not

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[21] PG&E Supplemental RTP Testimony, Ch. 2, p. 30 beginning at line 15.

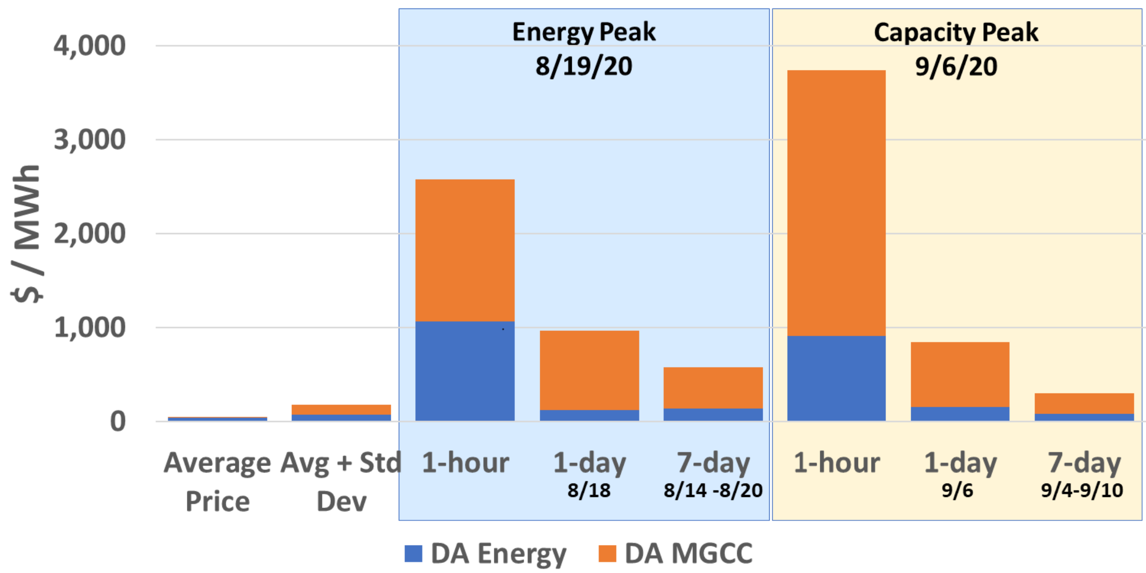
[22] PG&E Supplemental RTP Testimony, Ch. 3, p. 22, lines 20-23.

[23] PG&E, workpaper for Exhibit PGE-RTP-1 (Supplemental RTP Testimony).

[24] For the August 19 event, the peak average daily price would have been on August 18 even though the peak hourly price would have been on August 19.

exceed $1,000 per MWh during either peak, and weekly average prices were even lower.

Figure 1: Illustration of Potential RTP Price Volatility



Considering all the data supplied by PG&E for 2016-2019, PG&E's proposal would result in the following average hourly RTP rates per kWh, including both the day-ahead energy and day-ahead MGCC components:

- Simple average: $0.046
- Average price at one standard deviation, a measure of typical volatility: $0.176
- Average price during the highest priced hour: $3.743
- Average price for the highest priced day: $0.965
- Average price for the highest priced week: $0.573

While customers are likely to be concerned by hourly prices of $3.74 and weekly prices that are ten times higher than average prices, these extreme events are simply not comparable to the unreasonably high $9 per kWh experienced by Griddy customers in Texas for over four days.[25]

As discussed below, we are proposing modifications to PG&E's RTP rate design that would significantly moderate hourly prices during more extreme demand conditions. For any such RTP rate design, PG&E and any third-party providers should be expected to present these or other similar data to customers so that they are informed about potential extreme events. Nonetheless, the Commission should be reassured that none of the RTP rate designs proposed by any party for PG&E would result in the kind of prices experienced by Griddy customers in Texas.

Q: Do you recommend any measures to mitigate the risk of bill volatility for customers, without reducing the price signals of RTP?

A: Yes. As discussed on the May 25 CPUC Workshop on Advanced DER and Demand Flexibility Management by Aloke Gupta of the Energy Division, bill volatility for customers could be reduced creating a transactive system to allow customers to lock in prices in advance. Customers could purchase their expected energy consumption at forward market prices and be credited for reducing usage below that level at high-cost times. Such a transactive system could be developed by PG&E or by third parties who can provide energy management services to RTP participants.

Q: Please summarize your findings with respect to the scope and timing for PG&E's C&I RTP Pilot.

A: We recommend the following findings to the Commission.

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[25] PG&E Supplemental RTP Testimony, Ch. 2, p. 30, line 18 through p. 31, line 3.

1. PG&E's development of its C&I RTP Pilot did not give adequate consideration to the participation of and particular interests of small businesses, who may have different challenges and capabilities than large businesses.
2. Small businesses may have a strong interest in the C&I RTP Pilot, as demonstrated by their participation in optional schedules with greater rate differentiation between TOU periods and in SCE's RTP rate.
3. Small business participation in the C&I RTP Pilot is more likely to occur when supported by off-the-shelf technology or third party expertise.
4. There is a potential for additional benefits or costs if customers are permitted to remain on the RTP pilot rate after the two-year evaluation period is ended.
5. There will be little cost and potentially some benefit if customers are permitted to enroll in the RTP pilot even after it has begun.
6. While PG&E's proposed RTP rate design will result in increased rate and bill volatility, the level of risk should be much lower than that experienced by some ERCOT customers in February 2021.

Q: Please summarize your recommendations with respect to the scope and timing for PG&E's C&I RTP Pilot.

A: We recommend the Commission direct PG&E to:

1. Extend the proposed C&I RTP Pilot to include rate schedules applicable to customers of all sizes;

2. Primarily rely on third-party product and service providers for recruitment of small business participants, as recommended by JARP;
3. Allow participants to remain on the RTP tariff, rather than being automatically transitioned back to the Otherwise Applicable Tariff (OAT);
4. File Advice Letters recommending immediate changes to or termination of the RTP rates, as discussed in our testimony above; and
5. Clarify that customers will be permitted to enroll in the RTP rate at any time that it is available as a rate option.

Q: Please summarize aspects of PG&E's C&I RTP Pilot that you support or do not contest.

A: We support or do not contest the following aspects of PG&E's application.

1. The C&I RTP rate should be offered as a pilot with no cap on total participation, with no guarantee to participants that it will be available beyond the two-year period and with no marketing of the rate to non-participants beyond the beginning of the pilot, unless PG&E determines that it desires more participants for evaluation purposes.
2. The C&I RTP Pilot launch and schedule should be coordinated with the proposed DAHRTP-CEV Pilot, if approved.
3. The C&I RTP Pilot should include a small number of CCAs or ESPs.
4. Cost recovery for the C&I RTP Pilot should use a memorandum account for tracking incremental pilot costs and future cost recovery.

5. PG&E should not pay participation incentives.
6. Customers should not be allowed to participate in both the RTP rates and load management programs that are driven by generation costs.[26]
7. Prices should be disseminated via API and a flat website by a pre-determined time on a day-ahead basis, and usage data should be made available to customers as described in PG&E's testimony.
8. Revenue under- or over-collection risk should be studied during the evaluation process and discussed with stakeholders.

III. Overview of Response to RTP Rate Design

Q: Please summarize your position on the rate design for the DAHRTP rate.

A: In our direct testimony, we recommended that RTP rates should be limited to the recovery of marginal energy costs. We were (and are) concerned that the method for collecting embedded costs allocated using the equal percentage of marginal costs (EPMC) method could result in some intra-class cost shifts over the long run. Since we filed that testimony, PG&E has modified its proposal to begin with a C&I RTP Pilot and we have conducted additional research and analysis for the DAHRTP-CEV Pilot proceeding; we now agree that it is reasonable to recover both marginal energy costs (MECs) and marginal generation capacity costs (MGCCs) in a DAHRTP rate.

We also agree with PG&E that the MEC rate should be based on CAISO's day-ahead market. We also agree that the ANL should be computed

[26] We have not evaluated specific programs to determine which may or may not be suitable for dual participation, but for purposes of this proceeding, we support PG&E's proposed approach on this topic. PG&E Supplemental RTP Testimony, Ch. 1, Attachment A-2.

based on day-ahead CAISO projections for purposes of calculating a component of the hourly MGCC rate.

Our recommendation on rate design for the DAHRTP rate includes the following components:

1) MECs – hourly prices based on CAISO day-ahead market including line losses, as proposed by PG&E
2) MGCCs – recovered through three equally-weighted components:
    a) Variable adder indexed to adjusted net load (ANL) using PCAF method
    b) Fixed adder triggered by Flex Alerts
    c) Fixed adder triggered by Restricted Maintenance Operations events
3) Revenue-neutral time-of-use (TOU) adder to collect other revenue requirements.

Our proposal does not affect recovery of the Power Charge Indifference Adjustment (PCIA) or Renewable Energy Certificates (RECs), which would not be time differentiated. The PCIA is proposed to be removed from generation rates in the Commercial and Industrial Rate Settlement. The value of a REC only depends on the quantity of load and not the time at which it is consumed.

Our proposal differs from PG&E's proposal in only two respects: computation of the day-ahead MGCC and revenue-neutral adders. As we testified in A.20-10-011, PG&E's proposal for the MGCC portion of the DAHRTP rate is a generally reasonable application of California's marginal cost methods, but our research suggests that the method can be improved significantly. The remainder of our testimony explains the evidence that supports our proposal and the details of how our proposal would work, as follows.

- Section IV – Issues with PG&E's ANL/PCAF Method
- Section V – Issues with Cal Advocates' CPP Method
- Section VI – SBUA Proposal for Hourly Marginal Generation Capacity Cost Rates
- Section VII – Design of the Revenue Neutral Rate Adder

IV. Issues with PG&E's ANL/PCAF Method

Q: What is your opinion of PG&E's proposal?

A: We agree that the proposal is a generally reasonable application of California's marginal cost methods to an RTP rate design. It is reasonable for the RTP rate to collect MGCCs as determined in a General Rate Case (GRC Phase 2), adjusted for losses and the planning reserve margin.

It is also reasonable to use forecast annual and hourly ANL to assign capacity costs to hours on a day-ahead basis. PG&E's method for calculating ANL was approved by the CPUC in D.17-01-006 for purposes of determining TOU periods and allocating marginal generation capacity costs to those periods using the Percent Capacity Allocation Factor (PCAF) method.[27] Each hour's PCAF is proportional to the amount that the forecast load is above a threshold, which has been set at 80 percent of maximum ANL load. An hour with a 90 percent ANL has a MGCC that is exactly twice that in an hour with

[27] D.17-01-006, pp. 17-18, 71-72 (Finding of Fact 15), and Appendix 1, p. 1. See also D.18-08-013, pp. 30-31, 156-157 (Finding of Fact 7). In D.17-01-006, the CPUC recognized ANL as including adjustments for nuclear and hydroelectric and in D.18.-08-013, the CPUC recognized that PG&E had added other renewable resources such as biomass and geothermal.

85 percent ANL. The use of a linear allocation in the ANL/PCAF method is probably reasonable for analyses involving the aggregation of many hours, such as determining TOU periods and allocating MGCCs to those periods.

In order to determine the ANL maximum load, and hence the threshold, PG&E reasonably proposes to forecast the annual peak ANL as the average of 10 weather-year scenarios.[28]

In its DAHRTP rate design, PG&E proposes to apply the ANL/PCAF method to real-time pricing for what appears to be the first time. If the ANL/PCAF method overstates or understates the MGCC for a particular hour, customers may shift loads in ways that increase reliability risk.[29] As PG&E noted in its 2017 GRC testimony, since the PCAF-weighted load method was first adopted by the Commission in 1993, it has been refined and improved on the initiative of PG&E or in response to recommendations from interested parties.[30] Since the ANL/PCAF method is being applied to a new circumstance, that method should be reviewed and improved.

We have two concerns with then ANL/PCAF method when used for real-time pricing. First, there is insufficient evidence to justify the use of a linear allocation of MGCCs based on hourly ANL. Second, there is substantial evidence that reliability risk – the driver of MGCCs – is better indicated by a

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[28] The weather year scenarios provide hourly load and renewable energy generation that are grossed up to match overall system forecasts for the year in which the ANL peak is required. PG&E, Direct Testimony, Ch. 2, p. 14.

[29] Fatigue from responding to high MGCC values in hours in which load reductions were not necessary may reduce response in hours when the load reductions would be most valuable.

[30] PG&E, Direct Testimony, 2017 General Rate Case Phase II (Amended December 2, 2016), A.16-06-013, Exhibit 2, Ch. 9, p. 1.

combination of the ANL/PCAF method and reliability events called by CAISO.

Q: Why do you state that there is insufficient evidence to justify the use of a linear allocation of MGCCs based on ANL?

A: While it is reasonable to assume that ANL and reliability are related in some way, we have been unable to locate any study that verifies and quantifies the relationship between ANL and reliability metrics. We have explored this issue in two analyses.

First, we explored the relationship between ANL, loss of load probability (LOLP) and expected unserved energy (EUE) using data from the Demand Response ELCC study completed for CAISO.[31] That study reported average ANL, LOLP, and EUE values for each hour in each month of 2019, for a total of 288 data bins.[32] Significant LOLP and EUE occurred only in hours with ANL over about 15,000 MW, as shown for LOLP in Figure 2.

However, out of the top 40 hour bins with the highest average ANL, only eight hours had EUE or LOLP greater than zero. Taken by itself, this analysis suggests that reliability risk is essentially constant for hourly ANL above 15,000 MW.

Figure 2 also illustrates the PCAF allocation for the 2019 data. The observed 15,000 MW threshold for LOLP is only about 62% of the maximum ANL, and half the hours with LOLP over 0.05% are at ANL levels below 80%

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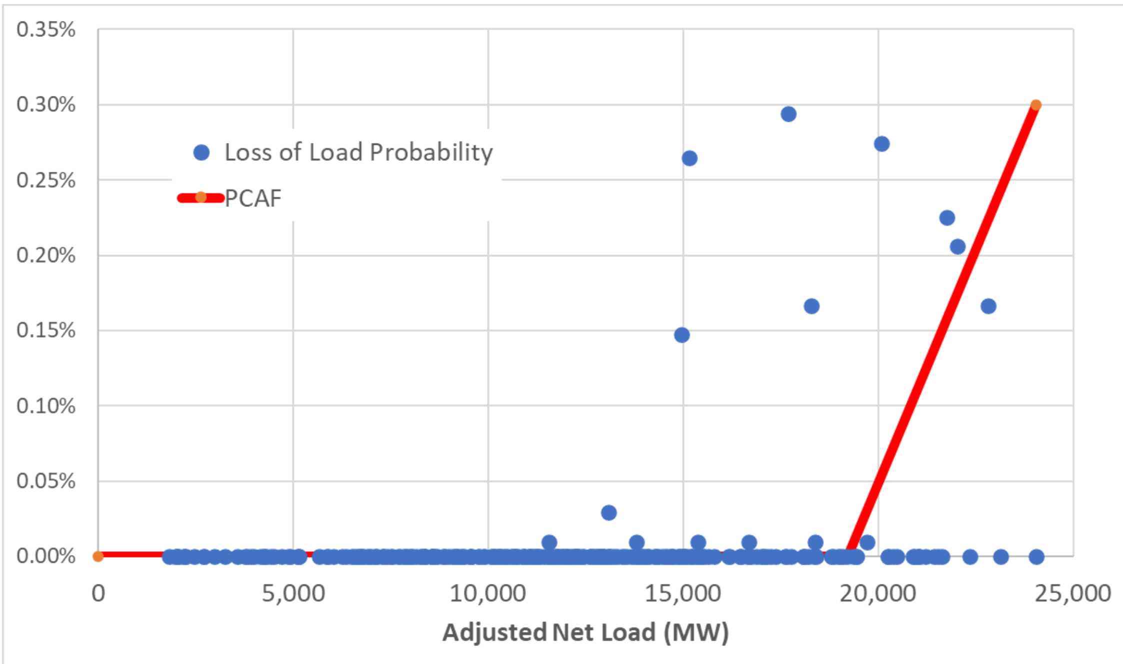
[31] Energy and Environmental Economics, *Demand Response ELCC* (December 2020). Available at: http://www.caiso.com/InitiativeDocuments/E3DemandResponseELCCStudy-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

[32] We calculated "average ANL" as the average ANL for the hour and month, including all ten weather-years included in the study. The data were provided by PG&E in response to an SBUA data request as shown in Attachment 12.

of forecast maximum ANL. Thus, much of the LOLP occurs in hours to which the PCAF assigns no capacity costs.

Figure 2: Adjusted Net Load, Loss of Load Probability and PCAF



Q: How else did you analyze the relationship between ANL and reliability metrics?

A: We have also studied the relationship between CAISO reliability events and system ANL. Our evaluation of 2017–2020 CAISO reliability events (Attachment 10) and system ANL data (Attachment 11) reveals that the relationship between system ANL and CAISO reliability events is not captured very well by the ANL/PCAF method.

1. About 12 percent of Flex Alerts hours and 79 percent of Restricted Maintenance Order (RMO) hours occur when ANL values are below 80 percent of the annual peak.

2. There is a roughly linear relationship between hourly system ANL and the probability of CAISO calling an advance Flex Alert for that hour.
3. Flex Alerts are called for only about one-fifth of hours when system ANL is above 80 percent of the annual peak.
4. RMOs are called for about three-fifths of hours when system ANL is above 80 percent of the annual peak.

CAISO issues an RMO when it is concerned that demand may approach available power supply (including imports and non-renewable generation). Flex Alerts indicate a higher level of concern.[33] While actual system ANL is correlated with the CAISO's system reliability events, it is not a sufficient indicator of reliability risk.[34]

We restricted our analysis to the 2017–2020 period, the time period over which PG&E provided hourly system ANL data (see Attachment 11). We also retained events called by CASIO for Southern California only because we were evaluating the relationship between system ANL data and system reliability events.[35]

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[33] We do not separately discuss Alerts, because nearly all of them are embedded in Flex Alerts. We found only one Alert in 2017–2020 that was not also recorded by CAISO as a Flex Alert; that was on August 15, 2020, in the midst of emergency declarations. That Alert was within an RMO. Either an Alert or a Flex Alert should be sufficient to trigger a DAHRTP price increment.

[34] Furthermore, the day-ahead ANL will differ from actual ANL.

[35] In order to study the relationship between a statewide ANL metric and RMO events, we included any event that might be related to ANL. Our workpapers include an analysis that excludes the Southern California regional RMO events, and we found no material effect on our conclusions in this alternate analysis. We address the exclusion of events called for Southern California only in the design of our proposal.

Q: Why did you consider the relationship between RMOs and other supply events?

A: CAISO issues an RMO to require generators and transmission operators to postpone any planned outages for routine equipment maintenance, maximizing the grid assets available for use. When CAISO issues an RMO, the reliability concern can be mitigated by a reduction in load just as easily as by postponing planned service outages.

It is also worth noting that while our analysis considered only day-ahead notifications, we also reviewed the qualitative relationship between RMOs, Flex Alerts, and system warnings and emergencies. We found that if a day-ahead alert was issued, then any system warnings and emergencies issued on the following day occurred during the period covered by the RMOs and Flex Alerts. Furthermore, four Flex Alerts called in 2017–2020 were called after 6 PM the prior day, too late to be reflected in PG&E's RTP; three of those would have been captured in RMOs called before 6 PM. Thus it appears that the schedules of RMOs are reasonable indications of the periods in which reliability events may occur.

One potential issue with CAISO RMO events is that they are typically called for an extended duration, including hours with low DA Energy Prices. We attempted to obtain a copy of CAISO Operating Procedure 4420B, which describes the basis on which RMO event durations are set, but this document is not publicly available.

CAISO indicates that an ISO-wide RMO notice will generally be issued when "The ISO is anticipating high loads and temperatures across the CAISO

Grid…"[36] At those times, reliability risk is elevated, creating the conditions that justify and require incurring additional capacity costs. The ISO uses this "authority to cancel or postpone any/or all work to preserve overall System Reliability."[37]

Even though "restricted maintenance operations are applied for the shortest duration necessary to meet the reliability concern,"[38] the scheduling of maintenance results in CAISO calling RMOs for periods longer than Flex Alerts or other events. For example, CAISO may include earlier hours, to ensure that units are available to return from maintenance in time to meet the hours of greatest concern.[39] In any case, CAISO generally calls RMOs for over 12 hours, and sometimes multiple days. Only a portion of the RMO period is likely to evolve into a capacity shortage. Thus, it could be appropriate for PG&E to limit the RTP adder to a portion of hours within the RMO event, perhaps based on TOU period, actual day-ahead energy prices above some defined threshold, or hours in which Flex Alerts have been called historically.

Q: How often are Flex Alerts and RMOs called when ANL values are below 80 percent of the annual peak?

A: PG&E's ANL/PCAF method limits the pricing signal to hours in which the ANL is above 80 percent of the forecast annual peak. our analysis shows that a significant number of CAISO reliability hours occur even when the ANL is

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[36] CAISO, *System Emergency Notice Templates*, Operating Procedure 4420C, Version 8.1, p. 8.

[37] CAISO, *System Emergency*, Operating Procedure 4420, Version 12.1, p. 3.

[38] *Id.*

[39] Again, more details may be available in the confidential CAISO Operating Procedure 4420B.

below 80 percent of the forecast annual peak. As shown in Table 2, most such event hours are RMOs, but about one in six Flex Alert hours is called when the ANL is below 80 percent.

Table 2: CAISO Reliability Event Hours by ANL, 2017-2020 (Percent of Forecast ANL Peak)

	> 80%	< 80%	Total	Percent of Events < 80%
Restricted Maintenance Order	213	816	1,026	**79 %**
Flex Alert	71	10	81	**12 %**

We conducted this same analysis, but considering only event hours that occurred during the peak and part-peak hours (2 PM – 11 PM, year round). As shown in Table 3, even with this limited time window, the majority of RMO event hours still occur during periods with ANL below 80 percent.

Table 3: CAISO Reliability Event Hours by ANL, During Peak and Part-Peak Hours Only, 2017-2020 (Percent of Forecast ANL Peak)

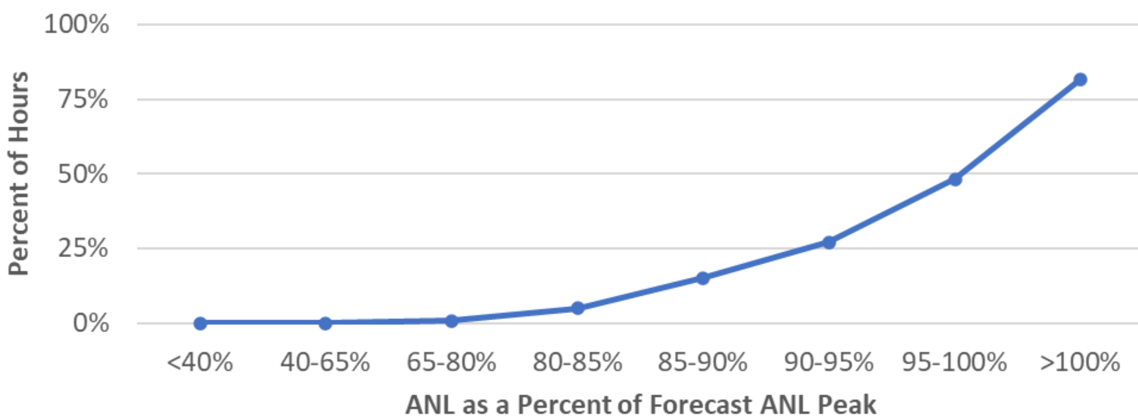
	> 80%	< 80%	Total	Percent of Events < 80%
Restricted Maintenance Order	212	227	439	**52 %**
Flex Alert	71	9	80	**11 %**

These CAISO events are valuable indicators of reliability risk, and hence are a cost basis for system capacity value. Yet many RMO and Flex Alert hours occur even when ANL peaks are below 80% of the forecast ANL peak. This demonstrates that ANL is not a sufficient indicator of reliability risk on its own.

Q: What is the relationship between system ANL and the probability of CAISO calling a Flex Alert for the same hour?

A: The probability of the CAISO calling a Flex Alert rises smoothly once the ANL exceeds roughly 80 percent, as shown in Figure 3.[40] Flex Alerts are called during only about 5 percent of hours for which system ANL is between 80 and 85 percent of the forecast ANL peak. At the other extreme, 82 percent of hours with system ANL exceeding 100 percent of the forecast peak (mainly during 2020) were covered by a Flex Alert.

Figure 3: Frequency of Flex Alerts, 2017-2020



The frequency of Flex Alerts supports the 80% cutoff point of the PCAF method, and the data suggests that reliability risk rises somewhere faster than ANL after that point. However, while supporting the general design of the PCAF method, our analysis also finds that the ANL can be greater than the forecast ANL peak without creating reliability risk.

[40] This analysis includes only events called early enough to inform PG&E's DAHRTP pricing, which we take to be 6 PM the prior evening.

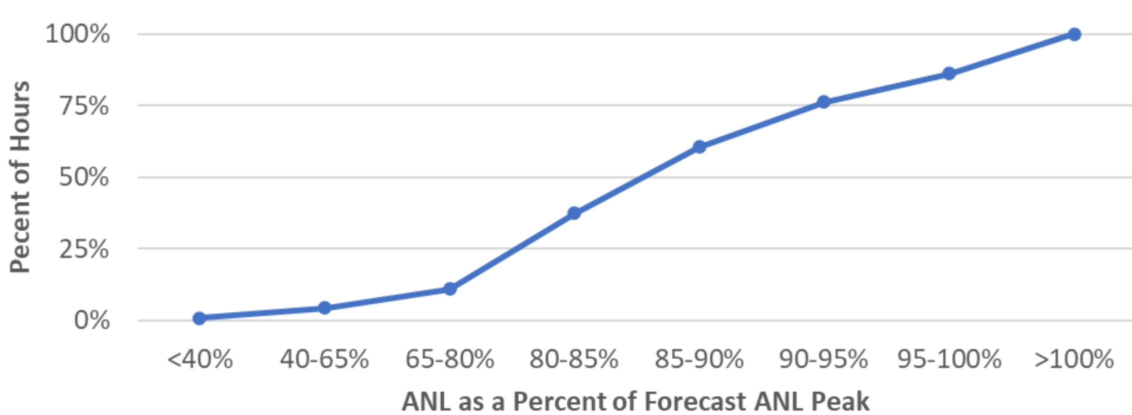
Q: How often are Flex Alerts called when system ANL is above 80 percent of the annual peak?

A: Flex Alerts are called only 19 percent of the hours in which system ANL is above 80 percent of the annual peak. The ANL was over 80 percent of the annual peak in PG&E's 2017-2020 dataset in 372 hours, and Flex Alerts were called for only 71 hours. While the probability of a Flex Alert does increase with ANL, even a relatively high ANL of 95-100% of forecast ANL peak has a less than 50 percent chance of predicting a Flex Alert (see Figure 3).

Q: How often are RMOs called when system ANL is above 80 percent of the annual peak?

A: Compared to Flex Alerts, RMOs are more likely to be called when system ANL is above 80 percent of the annual peak, with an overall frequency of 57 percent. As shown in Figure 4, the relationship between RMOs and ANL is roughly linear above about 70 percent.[41] Even though most RMO hours occur when the ANL is below 80 percent (see Table 2), there are very many hours in that range, and Figure 4 shows that the frequency of RMOs is very low when the ANL is below 80 percent.

Figure 4: Frequency of Restricted Maintenance Orders, 2017-2020



[41] Note that the 65-80% data bin is three times the size of the 80-85% data bin.

Q: Please summarize your findings and recommendation with respect to the method for allocating marginal generation capacity costs to hours.

A: We recommend the following findings to the Commission.

1. It is reasonable to assume there is a causal relationship between ANL and reliability and that some variant of the PCAF method would be appropriate for assigning MGCC values to high-ANL hours.
2. No recent applications of the PCAF method have demonstrated how hourly ANL is quantitatively related to reliability metrics.
3. It is reasonable for PG&E to apply the PCAF method as used in cost allocation for purposes of allocating MGCCs to hours for purposes of the C&I RTP Pilot.
4. For long-term application of the PCAF method to an hourly rate, further evidence is required to demonstrate the quantitative relationship of hourly ANL to reliability risk metrics.
5. Hourly ANL is an imperfect indicator of reliability risk. High-ANL hours are not particularly good predictors of the Flex Alert events, which mark hours in which CAISO is concerned that load may exceed supply. High ANL hours occur when the system does not experience reliability risks.
6. CAISO declares RMO events more often than Flex Alerts and for longer periods.
7. The Flex Alerts and RMOs are more direct measures of risk than ANL and a majority of the MGCC should be assigned to hours based on when CAISO calls those events.

In our direct testimony in the DAHRTP-CEV Pilot proceeding (A.20-10-011), we recommended that the Commission should direct PG&E to conduct further study to establish the quantitative relationship of hourly ANL to reliability metrics. In reply testimony, PG&E agreed, stating that "there may be a more accurate formula than PG&E's industry-standard PCAF formula to estimate reliability impacts from ANL."[42] PG&E provided further details regarding how such research might be conducted, including consideration of the hydro adjustment raised by Cal Advocates, and welcomed the involvement of SBUA, Cal Advocates, and other interested parties.[43]

V. Issues with Cal Advocates' CPP Method

Q: What are Cal Advocates' concerns about the ANL/PCAF method?

A: While Cal Advocates is generally supportive of the ANL/PCAF method, it has filed testimony in the DAHRTP-CEV Pilot proceeding (A.20-10-011) describing two concerns about utilizing it to set the entire MGCC component of the DAHRTP rate.

First, Cal Advocates expresses concern about the link between PG&E's proposed MGCC rate component and reliability risks. Cal Advocates opines that in order to "send meaningful price signals indicating operational and reliability risks, [the DAHRTP rate] should reflect the timing of the highest risk of reliability events."[44] In support of its concern, Cal Advocates' evidence

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42 PG&E, Reply Testimony, A.20-10-011, Ch. 2, p. 20, lines 17-19.

43 PG&E, Reply Testimony, A.20-10-011, Ch. 2, p. 7, lines 17-26; p. 20, line 29 through p. 21, line 23.

44 Cal Advocates, Testimony, Ch. 1, p. 8, lines 13-14.

suggests that “PG&E’s proposal will not sufficiently capture CAISO Flex Alert or Alert events.”[45]

Second, Cal Advocates expresses the concern that “PG&E’s generation PCAF proposal would result [in] unreasonable variations in the MGCC price signal and in revenue collections that would be dependent on weather conditions, not underlying costs … [since] the effective MGCC price signal that gets sent through rates can be significantly above or below marginal costs.”[46]

Based on these concerns, in the DAHRTP-CEV Pilot proceeding, Cal Advocates recommends two changes to the ANL/PCAF method. First, Cal Advocates proposes to modify the PCAF calculation based on hydrologic conditions.

Second, Cal Advocates proposes that the “DAHRTP rate should provide price signals that incentivize an effective customer response to Flex Alerts and Alerts, helping to prevent or mitigate CAISO reliability events.”[47] Specifically, Cal Advocates recommends a “dynamic CPP component of the DAHRTP rate that would be called on a day-ahead basis and could vary in duration from two to six hours during the hours 3:00-9:00 pm.”[48]

Q: Do you support Cal Advocates’ recommendation to adjust the ANL forecast using January – April hydro generation data?

A: We take no position on this proposal. However, we note that if this or some similar proposal is adopted, it will result in a definition of ANL for the

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[45] Cal Advocates, Testimony, Ch. 1, p. 10, lines 12-13.

[46] Cal Advocates, Testimony, Ch. 1, p. 17, lines 11-16.

[47] Cal Advocates, Testimony, Ch. 1, p. 8, lines 22-23.

[48] Cal Advocates, Testimony, Ch. 1, p. 13, lines 10-12.

DAHRTP rate that differs from that used in PG&E's General Rate Case applications for other purposes. To avoid confusion, it may be useful adopt a new terminology if an RTP-specific metric for ANL is developed.

Q: What is your opinion of Cal Advocates' proposed dynamic CPP component of the DAHRTP rate?

A: We find a lot to like about the proposal, although we have some specific concerns. We agree with Cal Advocates that the DAHRTP rate should reflect the timing of the highest risk of reliability events, as discussed in Section IV of our testimony. Furthermore, we agree with Cal Advocates that day-ahead alerts from CAISO are the most valid measure of the risk of reliability events.

However, we disagree with Cal Advocates regarding the revenues that should be recovered through a dynamic CPP component. We also disagree regarding the limitation of the dynamic CPP component to a maximum of six hours per event, occurring during the hours of 3 PM to 9 PM, and totaling between 15 and 50 hours per year.

Q: Why do you disagree with Cal Advocates regarding the size of the revenue requirement that should be linked to a dynamic CPP component?

A: Most fundamentally, we believe that a DAHRTP rate design that collects revenues to offset marginal generation capacity costs should collect greater revenues in years with unusually high reliability stress. If pricing is to be "real time," then it does not make sense to collect the same amount of revenues in a year with relatively mild demand and ample supply as in a year with an extremely tight supply-demand balance.

On the other hand, we also share Cal Advocates' concern with "large annual swings in revenue collections" and the associated burden on RTP customers in years with many high-risk hours.

Cal Advocates' rate design proposes to reduce PG&E's "PCAF generation price signals by 15% while concentrating the 15% PRM costs in [50] hours of the year."[49] Cal Advocates' justifies this approach as a cost-based approach, as follows:

- The 15% PRM costs are the costs of maintaining an operating and planning reserve margin necessary to provide reliable service in case of high demand and contingency events, and assigned based on CAISO's assessment of reliability risk; and
- The 85% remaining reflect the marginal value of generation capacity, excluding the costs of maintaining the PRM.[50]

Cal Advocates' suggestion to distinguish between the non-PRM and PRM components of marginal generation capacity costs is novel and fundamentally unnecessary. Combined with Cal Advocates' proposal to charge the full PRM rate during 15–50 hours every year, but to charge no PRM rate during some other hours with CAISO events that indicate reliability risk, this approach does not closely align rates with costs. As we will discuss below, there are other reasonable ways to allocate MGCCs to link them to reliability risk.

Q: Why do you disagree with Cal Advocates regarding the limited duration of its recommended dynamic CPP rate component?

A: Cal Advocates recommends limiting its proposed dynamic CPP rate component, which tracks Flex Alert/Alert hours, to six hours each, in the

[49] Cal Advocates, Direct Testimony, A.20-10-011, Ch. 1, p. 15, lines 16-17. Cal Advocates has updated its upper limit from 20 to 50 hours per year. Cal Advocates, Reply Testimony, A.20-10-011, Ch. 1, p. 13, lines 16-19.

[50] Cal Advocates, Direct Testimony, A.20-10-011, Ch. 1, p. 15, lines 11-21.

period 3 PM to 9 PM, and to a total of 15–50 hours per year because of concern about whether customers "would be able to maintain significant load reductions" for 12 hours or longer, the interval for which it believes very high prices could result from a combination of its proposed dynamic CPP events and PGE-proposed ANL-based allocation of most MGCC costs.[51]

This restriction violates Cal Advocates' stated goal of reflecting the timing of the highest reliability risks in the DAHRTP rate. While we agree that any customer would find it difficult to maintain maximum load reductions for 12 hours or longer, we view Cal Advocates' concern as misplaced, for six reasons.

First, the number of Flex Alert hours per year is generally rather low. The number of Flex Alert hours averaged 18 per year from 2011 to 2020 and 28 from 2017 to 2020.[52] These averages are heavily influenced by the 67 Flex Alert hours in 2020. Even under the extreme conditions of 2020, the longest Alert or Flex Alert was 7 hours.

Second, in years with a relatively high number of dynamic CPP events, customers will generally be aware of the extreme circumstances (as they were in 2020) and understand why the high rates are in effect more frequently than in a typical year.

Third, establishing a limited daily CPP period would constrain PG&E's ability to provide the load reductions that CAISO requests. For example, if

[51] Cal Advocates, Direct Testimony, A.20-10-011, Ch. 1, p. 13, lines 6-7; p. 14, lines 4-6. The A.20-10-011 testimony refers to "commercial EV fleet operators," but similar issues may arise for other commercial customers.

[52] CAISO, AWE Grid History Report, March 4, 2021. Note that throughout our testimony, where we refer to Flex Alert events, our analysis of CAISO data excludes Flex Alerts called after 6 PM prior to the event day for reasons discussed in our proposal.

CAISO issues a Flex Alert for 1 PM – 5 PM, under Cal Advocates' proposal, the dynamic CPP rate would increase suddenly at 3 PM. This rate design would not encourage customers to reduce load during the 1 PM – 3 PM time period, working against the intent of CAISO's Flex Alert.

Fourth, limiting the annual CPP hours would require PG&E to select hours within the CAISO event, second guessing the decision at CAISO to issue a Flex Alert for a particular period of time and forcing PG&E to guess whether the limited hours of CPP should be used or held back for events later in the summer. In 2020, if PG&E had called CPP events every time CAISO declared a flex Alert, it would have exhausted its 50 hours before the last events in October.

Fifth, Cal Advocates' proposal to include more hours in a dynamic CPP rate component reduces the hourly ANL-based rate. Whatever costs are allocated to the dynamic CPP rate component will be spread over more hours, resulting in a more modest bill effect (but a still substantial price signal) for those hours. While customers may find it difficult to maintain maximum load reductions for many contiguous hours, customers will be able to respond to the price signals by deferring some loads to another day or into the hours with lower MECs and ANL-based charges.

Sixth, Cal Advocates' concern with 12 hours of high prices conflates the relatively short period of Flex Alert events and the period for which ANL is high. As we discuss Section VI below, adding a price increment linked to CAISO reliability events to the MGCC computation reduces the ANL charge, resulting in lower MGCC charges for high-ANL hours outside those events.

Q: What other concerns do you have with Cal Advocates' proposed dynamic CPP rate component?

A: We have two additional concerns with the dynamic CPP rate component proposed by Cal Advocates in the DAHRTP-CEV Pilot proceeding.

First, Cal Advocates supports its proposal with an analysis of historical data that does not reflect the realistic operation of the DAHRTP rate, which is proposed to be set a day in advance. Cal Advocates suggests that a six hour event duration would capture 88.9% of events in 2020, and thus only one hour of one event would be missed by its proposed rule.[53] The historical actual CAISO emergencies and interruptions are only a subset of the hours in which CAISO declared Flex Alerts. Cal Advocates computes the length of the emergencies and interruptions, which are known only after the event, and not for the Alerts and Flex Alerts that would trigger day-ahead CPP calls. The Alerts and Flex Alerts are typically longer than the emergencies and interruptions, and PG&E has no way of knowing which alert hours will become emergencies or worse. The Flex Alerts in 2020 all lasted until 10 PM or 11 PM, as did five of the nine Alerts that were announced early enough to trigger a CPP call.

Second, Cal Advocates' proposes that PG&E call CPP events on a discretionary basis, with a minimum of 15 hours per year. Since the proposed DAHRTP rate reflects generation costs, it makes more sense to link any price triggers to CAISO alerts. If PG&E has discretion on calling CPP events, it may be more difficult to get CCAs to coordinate with this rate design. Furthermore, requiring a 15 hour minimum could result in PG&E calling CPP events during hours with relatively low reliability risk.

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[53] Cal Advocates, Direct Testimony, A.20-10-011, Ch. 1, p. 12, lines 5-13.

Notwithstanding some areas of disagreement, we appreciate Cal Advocates' suggestion that the CAISO Alerts and Flex Alerts be used in assigning MGCC costs to hours. Cal Advocates' review of the relationship between PG&E's simulated, historical hourly MGCC rates and historical incidence of CAISO Alerts and Flex Alerts informs our response and the evaluation presented in Section IV of this testimony.

VI. SBUA Proposal for Hourly Marginal Generation Capacity Cost Rates

Q: Please summarize your proposal.

A: We propose that the MGCC component of the DAHRTP rate comprise three equally-weighted components, as follows.

1. PG&E's ANL/PCAF method, potentially as modified by Cal Advocates to reflect hydrological conditions;
2. An hourly Flex Alert event price; and
3. An hourly RMO event price.

PG&E's proposed rate design takes its proposed MGCC from its GRC Phase 2 Application, plus a 15% PRM adder and a line loss factor of 1.091, resulting in a total annualized marginal capacity value of $87.04/kW-year.[54] We thus propose allocating $29.01/kW-year to each of the three elements.

For PG&E's ANL/PCAF method, this allocation would simply reduce the price to one-third of PG&E's proposed values. PG&E's historical back-cast of its MGCC rate for 2017–2020 identifies that the rate could reach

[54] As summarized by Cal Advocates. Cal Advocates also notes that the DAHRTP rate should be updated according to the final MGCC value adopted by the Commission in the GRC Phase 2. Cal Advocates, Direct Testimony, A.20-10-011, Ch. 1, p. 14, lines 16-18.

$3.46/kWh;[55] under our proposal the ANL/PCAF portion of the rate would reach only $1.15/kWh.

For the hourly Flex Alert and RMO event prices, we propose that the $29.01/kW-year would be allocated based on the average number of events in the past ten years.

- We excluded all Southern California-only events from the count. It would not be appropriate to charge PG&E customers based on a regional reliability event that does not affect PG&E.
- For Flex Alert and RMO event prices, we excluded all events that CASIO notified after 6 PM on the day prior to the event in order to be consistent with the DAHRTP-CEV Pilot advance notification process.

Over the past ten years, there were an annual average of 22 Flex Alert and 140 RMO reliability hours.[56] Dividing the $29.01/kW-year portions of the MGCC over those hours yields a rate of $1.31/kWh for Flex Alert hours and $0.21/kWh for RMO hours.

Using PG&E's historical back-cast of its MGCC rate, and assuming that the maximum occurred during an hour in which CAISO called both a Flex Alert and an RMO event, then the total DAHRTP MGCC rate element would be $2.67/kWh, which is significantly lower than PG&E's maximum rate.

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[55] Obtained from PG&E's attachment to our Attachment 11: GRC-2020-PhII_DR_SBUA_005-Q01Attch02, Tab "Price Analysis," Column J.

[56] The two Alerts that were not Flex Alerts would add about one hour to the annual average for all alerts.

Q: Why do you assign a majority – two-thirds – of MGCC costs to CASIO event triggered price adders?

A: Since the CAISO determinations of reliability risks (reflecting all load and supply considerations) are more direct measures of the need for load reductions than the ANL value (which accounts for only expected load and non-dispatchable generation), the CAISO events should drive the allocation of the majority of the MGCC. For simplicity, we suggest allocating PG&E's full MGCC (including the PRM) equally among the three components. However, we have no objection to some other weighting among the three components, especially if that weighting can be supported by some evidence.

Q: What will be the effect of SBUA's proposal on revenue over- and under-collections?

A: Our proposal may have a more moderate effect on both monthly and annual billing variability than the proposals from PG&E and Cal Advocates, while more effectively linking the pricing signal to the timing of the highest risk of reliability events.

To demonstrate the effect, we created total DAHRTP rates reflecting the proposals from PG&E, Cal Advocates, and SBUA, as follows.

- For PG&E, we obtained the hourly marginal generation capacity and energy costs for 2017-2020.
- For Cal Advocates, we used the same energy costs, 85 percent of the generation costs, and manually coded CPP events for the remaining 15 percent of the generation costs. We coded 20 hours of CPP events for every year except 2018 (which had 15 hours), prioritizing Flex Alert hours first, then RMO hours with high ANL, and finally high ANL hours. We did not reflect Cal Advocates' hydro proposal in

- this analysis, nor have we updated our analysis to reflect Cal Advocates' revised cap of 50, rather than 20, hours per year.
- For SBUA, we used the same energy costs, 33 percent of the generation costs, and obtained Flex Alert and RMO hours from CAISO data sources. We excluded Flex Alert and RMO hours that were not noticed in advance of 6 PM, as well as RMO hours that were called for Southern California only.

Using the resulting (nearly) four years of hourly pricing data for both MECs and MGCCs, we have constructed two figures to illustrate how total DAHRTP pricing in our proposal would differ from PG&E and Cal Advocates' proposals.[57]

Figure 5 illustrates how prices vary among the proposals on an hour-by-hour basis. We have selected the top 600 hours based on PG&E's pricing. This means that some of the top 600 hours based on Cal Advocates' or SBUA's pricing are not included in this figure.

In Figure 5, the effect of the use of event-triggered prices by Cal Advocates and SBUA is evident. For the Cal Advocates' case (as proposed in Direct Testimony), there are 15-20 hours per year in which their proposed CPP event triggered price increment is reflected. As a result, there are two pricing curves, each displaced from the PG&E curve by a similar amount.

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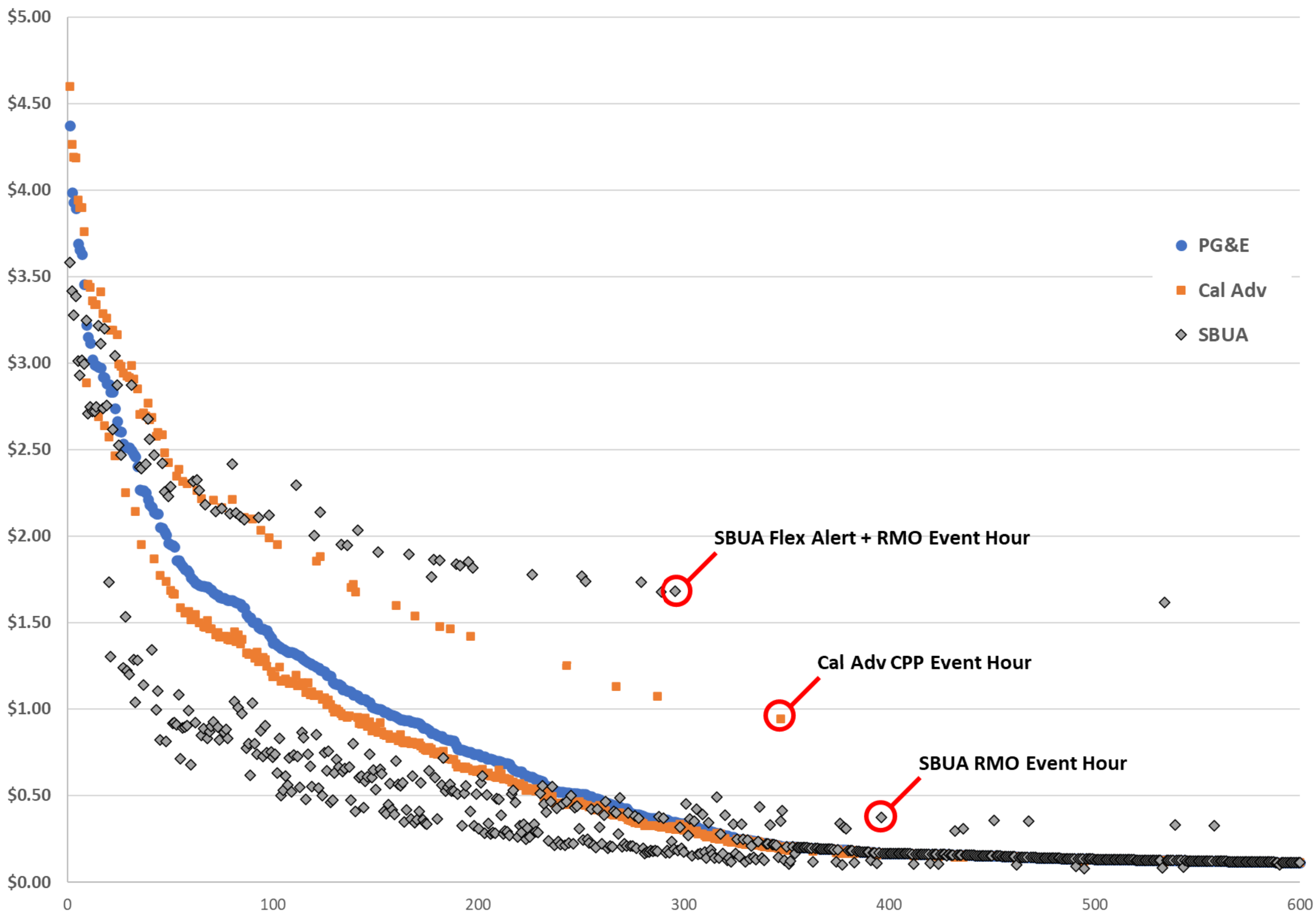
[57] We acknowledge Cal Advocates' analysis of effective MGCC price signals. We were unable to utilize this method to analyze our proposal because we do not know when CAISO might call reliability events in 2021.

Figure 5: Top 600 Highest Priced DAHRTP Hours, 2017-2020, Sorted by PG&E Proposal



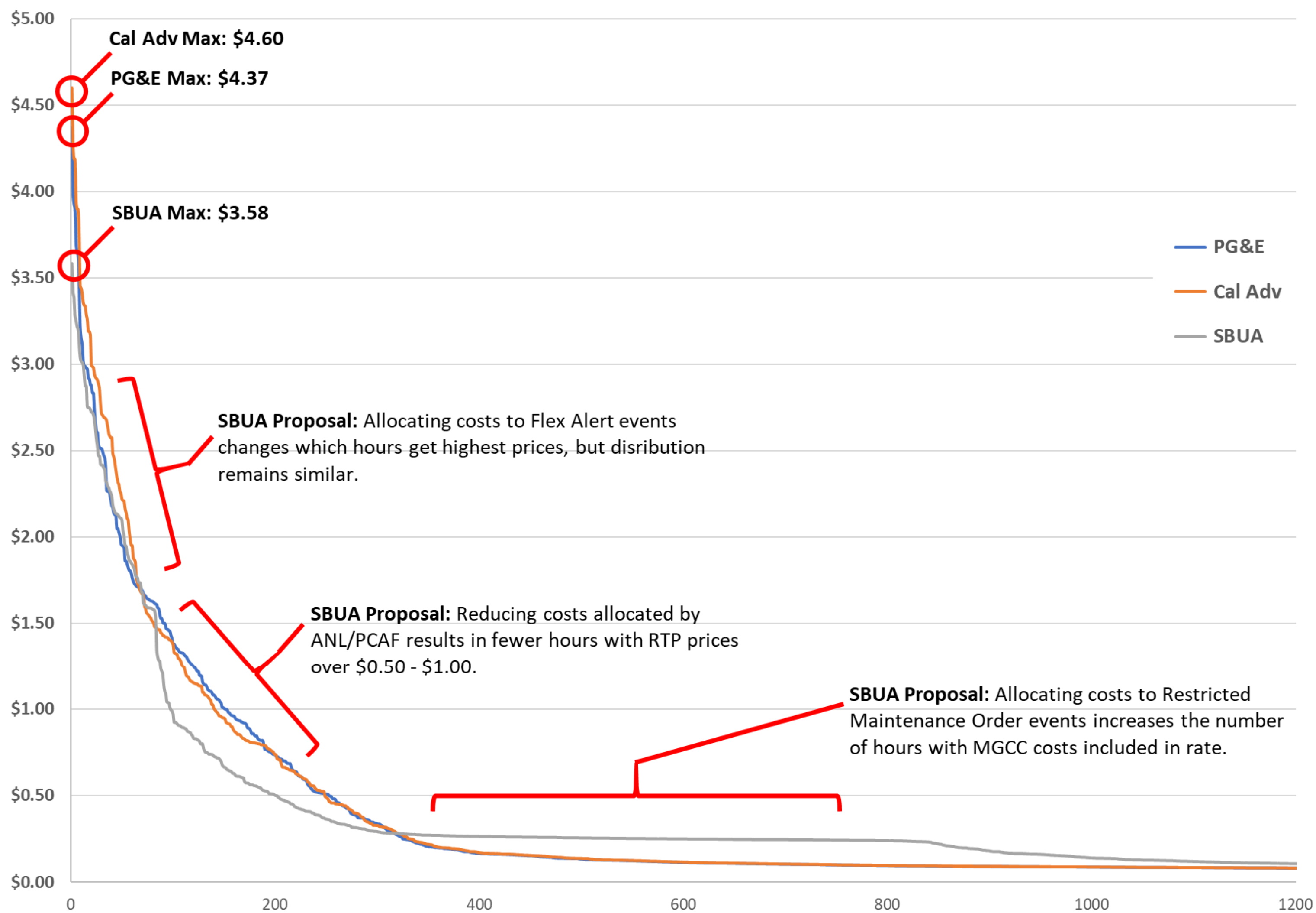
For our proposal, the displacement from PG&E's curve is more substantial. On Flex Alert days, the SBUA pricing is similar to Cal Advocates' CPP events, although a bit flatter because of the reduced sensitivity to the ANL/PCAF pricing component. Flex Alert days almost always include a pricing increment due to RMO events as well.

Another feature of our proposal is much lower pricing during a significant number of high-priced hours under PG&E and Cal Advocates' proposals. These are days on which no CAISO reliability event, or only an RMO event, was called. We believe this is an indication that our proposal aligns prices with reliability risk more effective than PG&E and Cal Advocates' proposals.

In Figure 6, we look at twice as many hours, and sort the pricing independently, so that these are the top 1,200 hours for each proposal. So the hours for SBUA's pricing curve are not the exact same 1,200 hours as are included in PG&E's pricing curve.

Figure 6 illustrates four further findings.

Figure 6: Top 1,200 Highest Priced DAHRTP Hours, 2017-2020, Sorted Independently



- SBUA's proposal has the lowest maximum rate.[58]
- For the highest price portion of the curve, SBUA's price curve is similar to the other two, but as shown in Figure 5, the mix of hours in this portion of the curve is significantly different.
- For the mid-range portion of the curve, SBUA has lower prices than the other pricing curves, reflecting the reduced ANL/PCAF component.
- For the lower portion of the curve, SBUA has higher prices reflecting a broader allocation of MGCCs to RMO event hours, which are often well below the 80 percent ANL threshold used in the other proposals.

We believe that these two analyses demonstrate that while the costs being allocated are identical, our proposal is likely to reduce bill volatility on a monthly and annual basis, while more effectively linking the pricing signal to the timing of the highest risk of reliability events.

VII. Design of the Revenue Neutral Rate Adder

Q: Please summarize PG&E's proposal for a revenue neutral rate adder.

A: PG&E proposes:

[58] Since we were unable to model Cal Advocates' hydro proposal, we are not certain how our proposal compares with theirs in this respect.

> "a rate adder that would collect other non-marginal costs collected in generation … as necessary to ensure that the rate is revenue neutral. The proposed revenue neutral rate adder would not vary by time of day. PG&E proposes to base all of its generation revenue neutral calculations on the bundled average generation rate."[59]

Based on the May 1, 2020 generation revenue requirement, PG&E proposes an adder of $0.05999/kWh.[60] PG&E's proposed treatment of the Power Charge Indifference Adjustment (PCIA) will eventually result in the PCIA being identified for bundled customers as a flat rate (not differentiated by season or TOU), but this will not affect the rate design in a meaningful way.

Q: What is your opinion of PG&E's proposal?

A: We agree that non-marginal generation costs (which will not be recovered through the RTP charges) should be collected in a revenue-neutral fashion. However, non-marginal generation costs should be collected as flat rates or differentiated by TOU period just as they are in the otherwise applicable tariff.[61]

Q: How should TOU rates be used to collect the other non-marginal costs?

A: The cost components that are not recovered through real-time pricing should be recovered as they are in the current TOU generation rates in the otherwise applicable tariff. Roughly two-thirds of PG&E's estimated revenue neutral rate adder consists of the PCIA,[62] which we would not modify.

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[59] PG&E, Supplemental RTP Testimony, Ch. 4, Attachment A, p. 10, lines 8-15.

[60] PG&E, Supplemental RTP Testimony, Ch. 4, Attachment A, p. 11, lines 5-7.

[61] The PCIA generation cost component would be collected from both RTP and non-RTP customers as a flat rate.

[62] PG&E, response to JointParties_001-Q02, Attachment 1, PGE worksheet, columns J and K.

For the remaining one-third of the rate adder, we would allocate the costs by TOU period based on the otherwise applicable tariff. We have filed a data request with PG&E to obtain an estimate of the resulting rates for various customer classes.

We also note that in the DAHRTP-CEV Pilot proceeding, Enel X's made a similar proposal for a TOU-varying revenue-neutral rate design. Enel X designed its rate using a credit method in order to make it possible to overlay the rate onto any existing tariff. The objectives and basic concepts behind SBUA and Enel X's proposals are identical, although one or the other may have technical advantages in terms of calculating new and updated rates. We are generally indifferent between the two approaches as the differences are merely in semantics and presentation.

Q: How would maintaining the TOU differential in the revenue neutral rate adder compare to PG&E's proposal for a flat adder?

A: Based on our analysis in the DAHRTP-CEV Pilot proceeding, PG&E's flat adder would result in little rate differentiation on most days. The average differentiation between super off-peak and peak rates using a flat adder would be about 5.5 ¢/kWh.[63]

In contrast, our proposal would begin with the rate differential already present in Schedule BEV, converting 5.5¢/kWh of the fixed TOU rate differential to an expected 5.5¢/kWh of real-time pricing, and maintaining the BEV rate differential of 22¢/kWh to 24¢/kWh.[64] On days with high ANLs—averaging 22 days per year—the rate differential would be much larger than

[63] SBUA Direct Testimony, A.20-10-011, p. 18, lines 9-11.

[64] SBUA Direct Testimony, A.20-10-011, p. 10, line 1.

normal under either approach. Our proposal would provide a more meaningful rate differential on average days and a slightly larger rate differential on days with high ANLs compared with PG&E's flat adder.

However, maintaining the rate differentials in the otherwise applicable tariffs may create unusual adders. In some rates, the TOU adder might be inverted – such as the super off-peak adder being higher than the off-peak adder. Since average RTP rates will be higher in off-peak than super off-peak periods, this counter-intuitive result is not material to the overall price signals that customers will receive. However, this result may indicate that the underlying rate design may require some adjustment.[65] In addition, some hours may have negative rates. This may be a result of previous rate design decisions to moderate (or enhance) the overall TOU differentials.

Q: Why is it important to provide a meaningful rate differential on average days?

A: Under our proposal, rate differentials would be virtually guaranteed to be larger than 17¢/kWh every day, giving customers the opportunity to charge at low super off-peak rates and encouraging them to shift load to that period. This would provide participants with an incentive to deploy and operate load management practices that reduce their bills without shifting costs to non-participants. This would help encourage widespread deployment of load management technologies, such as battery storage.

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[65] If that relationship occurs in the actual rate computation, and the Commission is concerned that the inverted TOU adders would confuse customers, it can require that PG&E set the off-peak and super off-peak adder components equal.

Q: Why could it make sense to use an inverted or even negative TOU adder to achieve rate design neutrality?

A: The goal of the DAHRTP rate design is to attract customers who would benefit from responding to price signals. PG&E's proposed flat adder converts non-marginal costs from a TOU rate design to a flat rate design, raising off-peak prices.

In the DAHRTP-CEV Pilot proceeding, PG&E argued that a TOU-varying revenue neutral adder is not cost-based because it "would artificially inflate the cost differences between peak and off-peak."[66] This is consistent with our understanding of the EPMC method's intent. PG&E's testimony provides no clear rationale as to why a flat rate is more cost-based than the TOU-varying rate used in the otherwise applicable tariff.

Without providing any rationale related to the purpose of the DAHRTP rate design, shifting from TOU-varying to flat rates would give customers an unrelated reason to shift from the otherwise applicable tariff to the C&I RTP Pilot. Some customers who might be able to reduce their bills merely by taking advantage of the shift from TOU-varying EPMC rates to flat rates. Without making any changes in their hourly loads, these customers would both fail to accomplish the purpose of the proposed C&I RTP Pilot as well as complicating evaluation of the pilot.

Q: Would your proposal potentially shift costs between participants and non-participants?

A: No. TOU-varying rates could be less likely to shift costs between participants and non-participants. During many hours of the year, participant loads are

[66] PG&E Reply Testimony, A.20-10-011, Ch. 1, p. 9, lines 1-4.

likely to be similar on the DAHRTP rate as compared to the otherwise applicable tariff because the rate difference will be relatively small. During hours in which a flat adder would be less than a TOU-varying adder, costs would be under-recovered from participants, and vice versa. The size and direction of the cost shift would depending on whether loads are higher or lower during under-recovery versus over-recovery periods.

In any event, 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 RTP customer behavior becomes available after the pilot.[67]

Q: Please summarize your findings with respect to the revenue neutral rate adder and subscription charge.

A: We recommend the following findings to the Commission.

1. It is feasible to maintain TOU-varying differentiation of the non-RTP portion of the otherwise applicable tariff in a DAHRTP rate.
2. A significant rate differential on an average day provides customers with a meaningful opportunity to apply load management technologies, which will help customers gain experience with their use and justify the investment.
3. Modifying non-marginal rate design in the otherwise applicable tariff to shift from TOU-varying to flat rates could attract participants who are not interested in the purposes of the C&I RTP Pilot and could cause unintended cost shifts.

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[67] PG&E Supplemental RTP Testimony, Ch. 4, p. 4, line 9 through p. 5, line 8.

4. Any shift of costs to or from non-participants can be mitigated by using a true-up in the ERRA proceeding. However, the expectation that participation in the C&I RTP Pilot means that the cost shift should be *de minimis* and should not require mitigation.

Q: Please summarize your recommendations with respect to the revenue neutral rate adder and subscription charge.

A: We recommend that the Commission modify PG&E's C&I RTP Pilot proposal by replacing the flat revenue-neutral rate adder with TOU-period generation rates.

Q: Does this conclude your testimony?

A: Yes.

Event	Start Datetime	End Datetime	Notice Datetime	Start Date	Start time HE	End Date	End time HE	Notice Date	Notice Time	Notice before cutoff?	Notes	SoCal?
RMO	1/3/17 0:00	1/3/17 12:00	12/30/16 14:07	1/3/2017	1	1/3/2017	13	12/30/2016	15	1		
RMO	6/19/17 0:01	6/22/17 22:00	6/18/17 14:26	6/19/2017	1	6/22/2017	23	6/18/2017	15	1		
RMO	7/7/17 7:00	7/7/17 22:00	7/6/17 8:36	7/7/2017	8	7/7/2017	23	7/6/2017	9	1		
RMO	8/1/17 6:00	8/1/17 22:00	7/31/17 8:33	8/1/2017	7	8/1/2017	23	7/31/2017	9	1		
RMO	8/2/17 6:00	8/2/17 22:00	7/31/17 8:36	8/2/2017	7	8/2/2017	23	7/31/2017	9	1		
RMO	8/3/17 6:00	8/3/17 22:00	8/1/17 12:56	8/3/2017	7	8/3/2017	23	8/1/2017	13	1		
RMO	8/21/17 6:00	8/21/17 20:00	8/4/17 15:22	8/21/2017	7	8/21/2017	21	8/4/2017	16	1		
RMO	8/28/17 6:00	8/31/17 22:00	8/25/17 8:54	8/28/2017	7	8/31/2017	23	8/25/2017	9	1		
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RMO	9/1/17 22:00	9/3/17 22:00	8/31/17 9:31	9/1/2017	23	9/3/2017	23	8/31/2017	10	1		
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RMO	3/2/18 6:00	3/2/18 22:00	3/1/18 17:48	3/2/2018	7	3/2/2018	23	3/1/2018	18	1		SoCal
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RMO	7/31/18 6:00	7/31/18 22:00	7/30/18 9:17	7/31/2018	7	7/31/2018	23	7/30/2018	10	1		
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RMO	8/24/20 6:00	8/25/20 22:00	8/21/20 8:30	8/24/2020	7	8/25/2020	23	8/21/2020	9	1		
RMO	9/5/20 6:00	9/8/20 22:00	9/3/20 9:29	9/5/2020	7	9/8/2020	23	9/3/2020	10	1		
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RMO	10/16/20 6:00	10/16/20 22:00	10/15/20 10:24	10/16/2020	7	10/16/2020	23	10/15/2020	11	1		
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Flex Alert	8/16/20 15:00	8/16/20 22:00	8/15/20 14:55	8/16/2020	16	8/16/2020	23	8/15/2020	15	1
Flex Alert	8/17/20 15:00	8/17/20 22:00	8/16/20 14:06	8/17/2020	16	8/17/2020	23	8/16/2020	18	1
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Flex Alert	8/19/20 15:00	8/19/20 22:00	8/18/20 14:56	8/19/2020	16	8/19/2020	23	8/18/2020	15	1
Flex Alert	9/5/20 15:00	9/5/20 21:00	9/3/20 9:05	9/5/2020	16	9/5/2020	22	9/3/2020	13	1
Flex Alert	9/6/20 15:00	9/6/20 21:00	9/5/20 14:22	9/6/2020	16	9/6/2020	22	9/5/2020	15	1
Flex Alert	9/7/20 15:00	9/7/20 21:00	9/3/20 9:05	9/7/2020	16	9/7/2020	22	9/3/2020	13	1
Flex Alert	10/1/20 15:00	10/1/20 22:00	9/30/20 14:54	10/1/2020	16	10/1/2020	23	9/30/2020	15	1
Flex Alert	10/15/20 15:00	10/15/20 22:00	10/14/20 17:33	10/15/2020	16	10/15/2020	23	10/14/2020	18	1
Alert	8/14/20 17:00	8/14/20 21:00	*8/13/20 14:57*	8/14/2020	18	8/14/2020	22	8/13/2020	15	1
Alert	8/15/20 17:00	8/15/20 21:00	8/14/20 14:24	8/15/2020	18	8/15/2020	22	8/14/2020	15	1
Alert	8/16/20 17:00	8/16/20 21:00	*8/15/20 14:55*	8/16/2020	18	8/16/2020	22	8/15/2020	15	1
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Alert	8/18/20 15:00	8/18/20 20:45	8/17/20 14:49	8/18/2020	16	8/18/2020	21	8/17/2020	15	1
Alert	8/19/20 17:00	8/19/20 20:00	*8/18/20 14:56*	8/19/2020	18	8/19/2020	21	8/18/2020	15	1
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Alert	10/1/20 18:00	10/1/20 19:00	*9/30/20 14:54*	10/1/2020	19	10/1/2020	20	9/30/2020	15	1
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PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	SBUA_004-Q01		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_004-Q01Supp01		
Request Date:	March 2, 2021	Requester DR No.:	004
Date Sent:	March 30, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Jan Grygier	Requester:	Jennifer Weberski

QUESTION 01

Please provide PG&E's most recent resource adequacy study and the following supporting data, all for the same modeling years:

1. Hourly adjusted net load, or the relevant load and generation components, corresponding to the entire CAISO footprint;
2. Hourly LOLE or equivalent metric, corresponding to the PG&E service territory; and
3. Hourly LOLE or equivalent metric, corresponding to any local resource adequacy areas that PG&E models separately

ANSWER 01

As ordered in D.19-09-043, the three investor owned utilities (IOUs) performed a joint study to assess the ELCC values used in Renewables Portfolio Standard (RPS) bid evaluations. That study (the Joint IOUs ELCC Study) is the most recent resource adequacy study that includes PG&E's service territory, and is provided as attachment "GRC-2020-PhII_DR_SBUA_03-Q01-Atch01_Joint IOU ELCC Study Wind Solar Hybrid July 2020.pdf."

The Joint IOUs ELCC Study modeled 2022, 2026 and 2030.

1. The Joint IOUs ELCC Study did not calculate or report adjusted net load (ANL). However, PG&E calculated hourly ANL for ten scenarios (corresponding to weather years of 2005 through 2014) for forecast years 2022, 2026 and 2030 as part of its modeling of Marginal Energy Costs (MEC) for the GRC Phase II. The hourly ANL for all ten scenarios for the indicated forecast years (as well as 2021) are provided as attachment "GRC-2020-PhII_DR_SBUA_03-Q01-Atch02_ANL_2021_2022_2026_2030.xlsb."
2. The requested data was not generated as part of the Joint IOUs ELCC Study.
3. The requested data was not generated as part of the Joint IOUs ELCC Study.

QUESTION 01 – SUPPLEMENTAL 01

a. Please provide the requested information or any similar information in PG&E's possession, regardless of whether it was produced for the Joint IOUs ELCC Study. To be clear, the request would cover modeling for 365 days for a current or future year, or typical days by month, or any other analysis that indicates the relative reliability risk by hour (and if available, day time) and season or month.

b. If PG&E has no information on the hourly LOLE for its service territory, please explain why PG&E decided that information would be not worth modelling.

c. If PG&E has estimates of hourly LOLE or equivalent metric for the CAISO system, please provide those estimates.

ANSWER 01 – SUPPLEMENTAL 01

a. PG&E does not have its own LOLE study, i.e. providing relative reliability risk by hour, day time, and season or month. If SBUA wishes to use information from another source, please see supplemental response to Q 01-c below.

b. PG&E objects to this question as assuming that hourly LOLE for its service territory would be worth modeling for this case.

c. Two relative reliability metrics for the CAISO system - Loss of Load Probability (LOLP) and Expected Unserved Energy (EUE) – are available on a month-hour basis (i.e., as a 12x24 matrix) from another source (e.g. Energy and Environmental Economics, Inc., or E3), as contained in the e-mail sent to you on March 26 on a preliminary basis, and as attached to this data response as file "GRC-2020-PhII_DR_SBUA_004-Q01Supp01.xlsx."

   The data in the attached file are outputs corresponding to historical conditions in 2019 and forecasted conditions in 2030 from a study E3 conducted for the CAISO looking at the effective load carrying capability of demand response. The study and data are public, available at http://www.caiso.com/InitiativeDocuments/E3DemandResponseELCCStudy-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

   While PG&E has already provided both historical and forecasted ANL data as part of its confidential workpapers for this proceeding, PG&E is also attaching its *public* calculated ANL values for 2019 and 2030 as file "GRC-2020-PhII_DR_SBUA_004-Q01Supp02.xlsx," for convenience.

   If SBUA is interested in using more granular data than appears in the E3 study, PG&E suggests asking Donald Brooks at the CPUC for a "debug report" from SERVM runs that were presented as part of the November 23rd Track 3.B Workshop in the RA proceeding, or alternatively from SERVM runs performed for the 2019-2020 Reference System Plan. PG&E understands that a SERVM debug report provides detailed information regarding load, renewables and other generation, as well as unserved energy and reserves shortfalls, that could prove useful to SBUA.

However, PG&E has not seen such a report and can make no guarantee as to its usefulness for SBUA's purposes.

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

PG&E Data Request No.:	SBUA_005-Q01		
PG&E File Name:	GRC-2020-PhII_DR_SBUA_005-Q01		
Request Date:	March 23, 2021	Requester DR No.:	005
Date Sent:	March 25, 2021	Requesting Party:	Small Business Utility Advocates
PG&E Witness:	Jan Grygier	Requester:	Jennifer Weberski

QUESTION 01

Pursuant to the March 23, 2021 email of Jan Grygier, please provide the following:

a. Calculations of historical hourly DA and RT MGCCs.
b. A comparison of DA and RT energy and capacity rates, including consideration of variability and forecastability.

ANSWER 01

a. Please see attachment "GRC-2020-PhII_DR_SBUA_005-Q01Atch01.xlsb"
b. Please see attachment "GRC-2020-PhII_DR_SBUA_005-Q01Atch02.xlsb"

Note that due to the size of the attachments…

PG&E reserves the right to make modifications to the above-referenced files prior to their release as workpapers for PG&E's March 29, 2021 filings.