STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
06/22/22
10:31 AM
A1911019

June 22, 2022 **Agenda ID #20730**
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 19-11-019 AND APPLICATION 20-10-011:

This is the proposed decision of Administrative Law Judge Doherty. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 4, 2022 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ ANNE E SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:smt

Attachments

Decision **PROPOSED DECISION OF ALJ DOHERTY (MAILED 6/22/2022)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation and Rate Design. (U39M.)	Application 19-11-019
(NOT CONSOLIDATED)	
Application of Pacific Gas and Electric Company (U39M) for Approval of its Proposal for a Day-Ahead Real Time Rate and Pilot to Evaluate Customer Understanding and Supporting Technology.	Application 20-10-011

DECISION ADOPTING REAL-TIME PRICING PILOT AND MARGINAL GENERATION CAPACITY COST STUDY AND ITS USAGE

Summary

This decision considers a study on the marginal generation capacity costs that should be used by Pacific Gas and Electric Company (PG&E) when calculating its rates, including its recently approved real-time pricing rate. This decision approves the study's methodology for calculating marginal generation capacity costs and orders PG&E to utilize the methodology as soon as is practicable. An uncontested settlement on real-time pricing pilots for certain

customers of Pacific Gas and Electric Company is also considered by this decision and is approved without modification.

Application (A.) 19-11-019 is closed while A.20-10-011 remains open.

1. Background

Decision (D.) 21-11-016 in Application (A.) 19-11-019 disposed of most substantive issues in the General Rate Case Phase 2 application of Pacific Gas and Electric Company (PG&E). Two other decisions, D.20-09-021 and D.22-03-012, addressed some of the remaining issues in the proceeding. However, real-time rate design is an issue that remains outstanding in A.19-11-019, and this issue requires resolution before the proceeding can be closed. PG&E and several other parties to A.19-11-019 filed a motion to adopt a joint settlement on outstanding real-time pricing issues (RTP settlement) on January 14, 2022. On March 15, 2022, PG&E served a study (hereinafter Marginal Generation Capacity Cost MGCC study) by several parties to A.19-11-019 outlining a proposed methodology to be used to generate an hourly marginal generation capacity cost price signal for the rate designs set out in the RTP settlement. A corrected version of the MGCC study was served on March 17, 2022 in A.19-11-019.

In parallel, a separate PG&E rate design proceeding (A.20-10-011) was also considering the question of how best to calculate PG&E's marginal generation capacity costs and apply those calculations to a new real-time pricing rate for non-residential customers providing charging services to electric vehicles, approved by the Commission in D.21-11-017.

On March 15, 2022, PG&E served the MGCC study as Exhibit PG&E-24 in A.20-10-011.[1] A corrected version of the MGCC study was served on March 17, 2022. As noted above, this service of identical copies of the MGCC study took place simultaneously in A.19-11-019 and A.20-10-011.

This decision now considers the questions of whether to approve the RTP settlement in A.19-11-019, and whether to adopt the MGCC study as a basis for calculating marginal generation capacity cost price signals in real-time rates approved by this decision and D.21-11-017.

2. Real-Time Pricing Options for PG&E Customers

While D.21-11-017 in A.20-10-011 approved a real-time pricing (RTP) structure for certain PG&E customers that provide electric vehicle charging services, a real-time rate design for other PG&E customers remains an outstanding issue to be resolved in A.19-11-019. Parties to A.19-11-019 filed voluminous testimony on RTP issues, and on January 14, 2022 a motion to adopt the RTP settlement was filed and served in A.19-11-019. Evidentiary hearing was held on January 26, 2022 in order to gather more information from the settling parties on the detail of the RTP settlement.

The RTP settlement is uncontested, and is signed by the Agricultural Energy Consumers Association (AECA), the California Large Energy Consumers Association (CLECA), the California Solar and Storage Association (CALSSA), Enel X North America, Inc. (Enel X), the Energy Producers and Users Coalition (EPUC), the Federal Executive Agencies (FEA), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Small Business Utility Advocates (SBUA), and PG&E.

[1] The MGCC study appears as Exhibit PG&E-RTP-7 in A.19-11-019.

The RTP settlement proposes a real-time pricing rate structure, for certain PG&E customers, with the following characteristics.

2.1. RTP Pilot Eligibility

Opt-in real-time pricing pilots would be available to bundled PG&E customers on B-20 (large commercial), B-6 (small commercial), and E-ELEC (residential) rates. Participation by unbundled PG&E customers on those rates would depend on Community Choice Aggregator (CCA) participation in the pilots. There would be no cap on the number of customers on those rate schedules that may enroll.[2]

Once the first real-time pilots (referred to as Stage 1 pilots in the RTP settlement) have begun, PG&E may file a Tier 1 Advice Letter to add any of the following additional commercial rates to the Stage 1 pilots: B-19, B-19 S, B-19 R, B-20 S, or B-20 R. PG&E would only do so if it determines that it is logistically feasible to include these other rate schedules.

Bundled net energy metering (NEM) customers would be eligible to participate in the pilots, and would have their generation export compensation vary by hour even if the generation price is negative (which would result in a generation-related charge, and not a credit).[3] Pilot participants with energy storage systems between one kilowatt (kW) and 10 kW, that are not separately metered, would be required to agree to work with PG&E to convey hourly charge and discharge data on a monthly or quarterly basis. CALSSA would encourage energy storage companies to use their best efforts to automate

[2] Transcript at 1034-1036, 1038.

[3] Eligibility for NEM customers taking service on any NEM tariff potentially revised by the Commission subsequent to the issuance of this decision would be determined through an Advice Letter process initiated by PG&E.

transmittal of customer-level hourly charge and discharge data monthly, or more frequently if possible. For pilot participants with battery systems having capacities greater than or equal to 10 kW, the same metering already addressed in the NEM successor tariff would be used for the Stage 1 pilots.

Customers enrolled in Stage 1 pilots would not be allowed to participate in certain other load management programs administered by PG&E, including demand response programs that are dispatched, or otherwise based, on day-ahead price signals or have energy-based payments, or programs that are dispatched based on day-of conditions such as the Base Interruptible Program, or programs that have day-of options such as Emergency Load Reduction Program established by the Commission in Rulemaking (R.) 20-11-003.

However, the RTP settlement does allow for future revision of this limitation, and proposes that the issue of "dual participation" between day-ahead RTP rates and day-of demand response programs would be considered in the Interim Evaluation Report described in Section 2.2 below. If PG&E determines it is able to mitigate some of the technical difficulties in doing so, PG&E would permit limited dual participation on the Base Interruptible Program and/or the day-of option for Emergency Load Reduction Program and the Stage 1 pilot to further evaluate impacts, including: 1) isolating ex-post and ex-ante load impacts from dual participants so they can be correctly attributed to each program, 2) Base Interruptible Program resource forecasting and counting, 3) double compensation, and 4) generation revenue over- and/or under-collection.

2.2. RTP Pilot Duration

The Stage 1 pilots would have a duration of 24 months, subject to potential extension after the Commission reviews the Interim Evaluation Report regarding the first 12 months of Stage 1 pilot operations.

The Interim Evaluation Report would be submitted as part of a Tier 2 Advice Letter 18 months after the targeted launch date of October 1, 2023 for the Stage 1 pilots. That Advice Letter would also include a recommendation as to whether the Commission should extend one or more of the Stage 1 pilot rates, either as is or with minor modifications, beyond the original 24-month period.

If the Commission does not approve that Advice Letter in a timely fashion, the Stage 1 pilots would be extended for an additional 90 days to allow PG&E adequate lead-time to complete its notifications to customers of the revised date on which they may be returned to their otherwise applicable underlying tariff.

2.3. RTP Pilot Enrollment

PG&E would begin to offer opt-in enrollment by October 1, 2023 for eligible customers. No Stage 1 pilots would be launched during the summer season (June 1 to October 1) of any year. Eligible customers would be allowed to enroll in any of the Stage 1 pilot rates at any time during the 24-month duration of the Stage 1 pilots.

Consistent with PG&E Electric Rule 12, Stage 1 pilot participants who de-enroll from a Stage 1 pilot would not be eligible to re-enroll until at least 12 months have elapsed. A customer's initial enrollment in a Stage 1 pilot would not be considered to constitute a "rate change" for purposes of PG&E's Electric Rule 12. However, a residential customer that receives a Smart Panel incentive when joining a Stage 1 pilot will be considered to have made a "rate change" if the customer seeks to de-enroll during the first year of their participation in the Stage 1 pilot.

2.4. RTP Rate Design

The real-time element of the Stage 1 pilot rates would replace the generation component of the customer's otherwise applicable rate schedule. The remaining transmission, distribution, Public Purpose Program and other charges and taxes would remain the same as the otherwise applicable underlying rate.

The real-time generation component to be used in the Stage 1 pilots would include: 1) a Marginal Energy Cost (MEC) price signal, 2) a Marginal Generation Capacity Cost (MGCC) price signal, and 3) a Revenue Neutral Adder (RNA).

With respect to the MGCC element, the RTP settlement wishes it to be based on the MGCC study and that it be identical to the MGCC element to be used for the electric vehicle charging real-time rate at issue in A.20-10-011.

The RNA is designed to make the forecasted annual generation revenue collected under the three Stage 1 pilot rates revenue neutral to the base schedule, which would help ensure that customers participating in the Stage 1 pilots contribute to the overall responsibility for generation revenue in their respective customer class. The RNA would also include the Power Charge Indifference Adjustment rate element, if applicable.

The methodologies for calculating the MEC and MGCC elements of the real-time rates would not change between general rate case (GRC) cycles, but the MEC and MGCC price signals themselves may change depending upon whether the Commission changes PG&E's approved marginal costs in the future. If revenue requirements change between GRC cycles, equal cents per kilowatt-hour adjustments will be made to the RNA to ensure that the real-time rate remains revenue neutral.

2.5. Potential for Under-Collection or Over-Collection of Generation Revenue

The RTP settlement grants that it will be difficult to calculate the amount of over-collection or under-collection of generation revenue from Stage 1 pilot participants, and therefore proposes to track and study generation costs and generation revenues over the course of the Stage 1 pilots, with no predefined mitigation or revenue recovery procedures.

PG&E would study over- and under-collection during the Stage 1 pilots and attempt to differentiate between over- and under-collection structural effects (*i.e.*, due solely to enrollment and disenrollment) and rate-induced changes in customer energy use. PG&E would also track each pilot customer's load profiles, both before and after they began participating in any of the Stage 1 pilots' rates and compare them to performance under non-RTP rates as well as the aggregate load of customers not-participating in the Stage 1 pilots. PG&E would identify those elements of the Energy Resource Recovery Account balancing account that may not be attributable to an RTP rate and will measure possible double counting of annual energy and capacity costs in Stage 1 pilot customers' rates.

If the study results indicate material and systemic over- or under-collections, PG&E and/or other parties to the RTP settlement may file a proposal to modify the RTP rate either during the Stage 1 pilots, or after their conclusion.

2.6. Consumer Protections, Incentives, and Outreach

The RTP settlement does not propose any particular consumer protections for commercial customers taking service on a Stage 1 pilot rate, other than the cap on the MGCC price per kilowatt-hour. However, for residential customers on a Stage 1 pilot rate, the RTP settlement proposes to protect those customers from unexpected bill increases by offering one year of bill protection.

Incentives would be tested for residential customers only on the Stage 1 pilot rate, with caps to control total costs. First, up to 1,000 residential participants would each be eligible for a $300 participation incentive, to be paid out in thirds, as follows: 1) $100 upon enrollment, 2) $100 upon completion of the survey after the first year of operations, and 3) $100 upon completion of the final survey at the end of the 24-month duration of the Stage 1 pilots. Second, there would be an additional incentive of $1,625 to help a maximum of 250 residential participants install Smart Panel[4] technology, to be paid in two installments: approximately 75 percent of the Smart Panel incentive ($1,225) will be paid at the beginning of the Pilot, with the remainder ($400) to be paid upon the participating customer's completion of the first-year survey.

To facilitate enrollment, the RTP settlement proposes that PG&E would reach out to customers with energy management systems, energy managers, storage systems, electric vehicle charging, heat pump space heating and/or heat pump water heating, and/or (for commercial customers only) high consumption during peak load periods. It also proposes that PG&E make program-specific marketing content available upon request to third parties and CCAs.

2.7. RTP Pilot Research and Evaluation

In conducting program evaluation, PG&E would engage qualified vendors to perform two measurement and evaluation studies: 1) an Interim Evaluation Report to be completed approximately 18 months after the Stage 1 pilots are launched, based on the available data from the first 12 months' operations of the

[4] According to the RTP settlement, Smart Panels allow customers to choose which loads to be powered at any time and control each individual household circuit. The research question addressed by the Smart Panel incentive is: "...rather than trying to find different [control] technologies for each of the major appliances in the home, is it easier [for a residential customer] to control [load] at the panel?" (Transcript at 1044.)

Stage 1 pilots, and 2) a Final Evaluation Report, based on the full 24 months of pilot operations (whether extended or not).

With respect to metrics, the RTP settlement proposes using the metrics proposed by PG&E in testimony and holding a workshop to elicit interested parties' suggestions for further developing and recommending to the Commission metrics for measuring and evaluating the Stage 1 pilots.

Program costs would be reported on a cost-per-participant basis wherever possible. Program cost metrics will be tracked on a fixed as well as a variable basis. The RTP settlement acknowledges that some costs considered "fixed" may actually vary depending on the number of participants and may not be fixed if the program were scaled from a pilot to standard rate option. PG&E proposes to identify those types of costs by the completion of the Final Report.

The RTP settlement proposes that PG&E conduct an additional Customer Research Study into dynamic pricing rate design and customer preferences for residential, agricultural, and small business customers, as described in PG&E's rebuttal testimony. PG&E would conduct a workshop to further define the objectives and methods for this research on rate design and preferences.

2.8. RTP Pilot Cost Recovery

According to the RTP settlement, all development, implementation, and operating costs for the Stage 1 pilots, as well as for the separate Customer Research Study for residential, agricultural, and small commercial customers, would be recovered in distribution rates from all customers, allocated by the Equal Percent of Total revenue allocation method.

These costs would be tracked in the Dynamic and Real Time RTP Memorandum Account (DRTPMA) for recovery in a future application. PG&E

would break out the costs for the Stage 1 pilots in A.19-11-019, and the RTP rate approved for commercial electric vehicle charging services approved in D.21-11-017. All recorded costs would be subject to a reasonableness review by the Commission. While an accurate estimate of total costs cannot be performed without knowing the bill protection costs that may be incurred, PG&E estimates that non-bill protection costs related to the Stage 1 pilots may amount to approximately $15 million.[5]

2.9. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Commission's Rules of Practice and Procedure (Rules) generally concerns settlements. Pursuant to Rule 12.1(d), the Commission will not approve a settlement unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. This standard applies to settlements that are contested as well as uncontested. The RTP settlement is uncontested.

2.9.1. Reasonableness in Light of the Whole Record

The RTP settlement motion claimed that the RTP settlement was reasonable in light of the whole record as it represented a give-and-take among the parties after careful review of their respective positions on RTP issues.[6] The Comparison Exhibit attached to the motion also reveals that the terms of the RTP settlement are compromise positions between the various positions taken by the parties in their testimony.

[5] Motion to adopt RTP settlement at 15, fn 16.

[6] Motion to adopt RTP settlement at 3-4.

The RTP settlement stated that the parties engaged in settlement negotiations for over one year, and that the settlement is a product of those efforts. While many issues were, in fact, uncontested, some contested issues included: 1) the number of rate schedules that should be included in the Stage 1 pilots and 2) which rates those should be. The selection of three rate schedules for inclusion – two commercial and one residential – reflects a compromise of litigated positions.

Another contested issue that the parties were able to settle was dual participation. PG&E originally proposed to prohibit all dual participation, while CALSSA and Enel X proposed to allow dual participation between the Stage 1 pilot and both the Base Interruptible Program and the Emergency Load Reduction Pilot. As a compromise, the RTP settlement initially prohibits dual participation while allowing PG&E to use the Interim Evaluation Report to discuss which dual participation challenges it believes can be sufficiently mitigated to allow potential testing of limited dual participation for Stage 1 pilot participants.

Given that the RTP settlement adopts positions that represent compromises of litigated positions on the record, this decision finds that the RTP settlement is reasonable in light of the whole record.

2.9.2. Consistent with the Law

The RTP settlement claimed that it was consistent with relevant statutes, Commission decisions, and public policy, including the Rate Design Principles adopted by the Commission in D.15-07-001. In particular, the RTP settlement proffered that its provisions would ensure that Stage 1 pilot residential rates are aligned with the Commission's cost-of-service, affordability, and customer acceptance principles.[7]

No party disputed that the RTP settlement was consistent with the law and no inconsistency with the law is apparent. Therefore, this decision finds that the RTP settlement is consistent with the law.

2.9.3. Consistency with the Public Interest

The RTP settlement indicated that it includes provisions for identifying potential under-collection and cross-subsidization concerns while allowing a limited Stage 1 pilot to proceed to gather key early learnings and hopefully deliver some initial greenhouse gas reduction benefits and generation cost savings as well and claimed that all of these are in the public interest.

The RTP settlement stated that limitations on the residential Stage 1 pilot result in a reasonable initial test on appropriate residential customers, while minimizing the incremental additional costs it adds to the Stage 1 pilots. As for rate design, the three RTP pilot test rates all focus on marginal generation costs, which are composed of MEC and MGCC. This approach would send a capacity price signal during the hours in which the grid is most stressed, in an effort to incent customers to reduce load in those hours. According to the RTP settlement, this could, eventually (once load shifting has been verified), yield reductions in the need to acquire as much battery storage generation capacity. If the RTP rates tested in Stage 1 are successful, the RTP settlement posits that the longer-term goal would be to reduce rates for all customers, and in the shorter term the RTP rate design's capacity price signal will help the grid to the extent that load is shifted out of those hours. The MGCC Research Study would provide

[7] Motion to adopt RTP settlement at 27.

information on the appropriate methodology to calculate a capacity cost that accurately signals grid stress in the day-ahead timeframe.

Normally, the Commission would consider the rate and bill impacts of a new rate design proposed by a settlement when assessing whether such a settlement was in the public interest. In this case, rate and bill impacts are unknown given that the rate will fluctuate on an hourly basis throughout the year, and complete illustrative rates are not provided. It appears that the RTP settlement attempted to mitigate rate and bill impacts for residential customers by applying a year of bill protection to those customers' bills, and for both residential and commercial customers by capping the marginal generation capacity cost signal in the rate. Because rate and bill impacts are unknown, and because the RTP settlement adopts certain mitigation measures for participating customers, this decision does not specifically evaluate rate and bill impacts of the proposed RTP rate when assessing whether the RTP settlement is in the public interest.

This decision agrees with the RTP settlement that the testing of real-time rate designs with the intent of reducing peak capacity costs faced by PG&E, and thereby reducing peak rates for all customers, is in the public interest.

2.9.4. Approval of RTP Settlement

In light of the findings laid out previously, this decision finds that the RTP settlement is reasonable in light of the whole record, complies with the law, and is in the public interest. Therefore, this decision approves the RTP settlement and PG&E shall implement its provisions as soon as practicable.

3. Marginal Generation Capacity Cost as a Real-Time Hourly Price Signal

For both the real-time rates approved as part of the RTP settlement in A.19-11-019, and the real-time rates already approved by the Commission in

D.21-11-017, it is necessary for the Commission to adopt a methodology for calculating the marginal generation capacity cost price signal in those rates.

3.1. MGCC Study

As a result of a stipulation adopted in D.21-11-017, and consistent with related rulings, a subset of parties to A.19-11-019 gathered together and studied PG&E's marginal generation capacity costs to develop a methodology for calculating a marginal generation capacity cost price signal. These parties – consisting of PG&E, SBUA, Cal Advocates, CLECA, and Enel X (Stipulating Parties)[8] – produced the MGCC study that was served in both A.19-11-019 and A.20-10-011 in March 2022. The scope of the MGCC study was to "analyze the relationship of the following variables to the condition of the [California Independent System Operator (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 Flex Alert Events, and 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, using [Strategic Energy Risk Valuation Model (SERVM)] data that Energy Division would provide."[9]

The MGCC study's primary purpose was to "determine the fit between alternative formulations of hourly [marginal generation capacity cost]... and capacity shortfall (reliability) metrics. The primary purpose of a real-time

[8] This decision specifically recognizes the diligence and efforts of the following individuals that contributed to the MGCC study: Paul Chernick, Jan Grygier, Benjamin Gutierrez, Matt Kawatani, Ryan Mann, Louay Mardini, Vanessa Martinez, John D. Wilson, and Catherine Yap.

[9] Exhibit PG&E-20 in A.20-10-011 at 1-2.

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."[10]

Commensurate with this purpose, the heart of the MGCC study served by the Stipulating Parties is a proposed methodology to calculate an hourly price signal for PG&E's new real-time rates that is based on an hourly calculation of PG&E's marginal generation capacity costs. This hourly price signal would increase greatly during times of severe grid utilization, subject to a cap on the maximum rate to be charged, based primarily on the adjusted net load that is forecasted by CAISO the day ahead for a given hour the following day.

The actual equation proposed by MGCC study for calculating a marginal generation capacity cost price signal for PG&E's real-time pricing rates is as follows: $\text{PCAF-S}(ANL_T) = H / (1 + \exp(A - B * ANL_T)) + E * \text{Flex Alert}$. The MGCC study further explains that:

- $\text{PCAF-S}(ANL_T < 27{,}713) = 0$ (i.e., the PCAF-S curve begins at CAISO-wide ANL_T of 27,713 megawatts)
- ANL_T is normalized using the formula $(ANL_T - \text{Min})/(\text{Max} - \text{Min})$, where Min/Max are the minimum/maximum ANL_T values in the dataset. The normalized values of ANL_T used in the equation range from 0 to 1.
- E (event-based adder) = $0.25
- H (maximum price contribution from the hourly PCAF-S function of adjusted net load) = $1.097
- A = 18.78
- B = 23.72

[10] Exhibit PG&E-20 in A.20-10-011 at 5.

- The hourly price is determined using the variables H (maximum price contribution from the hourly PCAF-S function of adjusted net load) and E (event-based adder), which are optimized to recover the total PG&E marginal generation capacity cost of $90.35/kilowatt-year in an average year
- Variables A and B are determined using logistic regression using historical data

The MGCC study noted that the specific values for H, A, B, and L may be updated by PG&E prior to program launch, reflecting additional historical data or any updates to the marginal generation capacity price of $90.35/kilowatt-year, using the methods described in MGCC study. The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.[11]

The Stipulating Parties make some adjustments to the CAISO net load figure in order to more accurately forecast hours of extreme grid stress, including: 1) using forecasted high temperatures in Pacific Northwest and Phoenix to help predict if generation resources throughout the western United States are expected to be less available for use by PG&E customers in a given hour, and 2) including a CAISO Flex Alert event "adder" of $0.25/kilowatt-hour (kWh) to account for other factors that may create stress in the grid and influence CAISO decisions to call Alerts, Warnings, and Emergencies (AWE) notification events. The Stipulating Parties also argue that this AWE adder leverages extensive publicity around CAISO Flex Alerts.[12]

In choosing a recommended marginal generation capacity cost pricing formula, the Stipulating Parties claimed that they considered both the accuracy of the signal (in terms of aligning with CAISO AWEs, which indicate

[11] Exhibit PG&E-25 in A.20-10-011 at 9.

[12] MGCC Study at i.

operationally times of high grid stress), as well as the year-to-year variability expected under various versions of the marginal generation capacity cost price signal. The Stipulating Parties argued that some of the benefits of the recommended marginal generation capacity cost pricing formula are:

- Non-zero marginal generation capacity cost prices at lower adjusted net loads
- A maximum hourly marginal generation capacity cost price component (rather than increasing indefinitely at higher and higher net loads)
- Lower year-to-year revenue variability, which should lower the likely magnitude of revenue over- and under-collections.

In terms of hypothetical bill impacts, the Stipulating Parties stated that they evaluated potential bill impacts on a prototypical medium to large commercial customer (*i.e.*, a Schedule B-6 customer). The real-time rate "would not substantially increase year-to-year variability in a customer's bill and it would provide a meaningful enhancement to the customer's 'profit' from use of a battery storage device."[13]

The MGCC study also recommended that the working group that produced the study be reconvened in the future, once evaluation of PG&E's real-time pricing rates has been completed, to re-evaluate the marginal generation capacity cost pricing formula.

Given the nature of the proposed marginal generational capacity cost pricing methodology, and the purported advantages of the approach, the Stipulating Parties recommended that the Commission adopt the proposed methodology as described in the MGCC study. No party to either A.19-11-019 or

[13] MGCC Study at ii.

A.20-10-011 objected to the marginal generation capacity cost pricing methodology and proposal as described in the MGCC study.

3.2. Joint Stipulation on MGCC-related Issues

Subsequent to the service of the MGCC study, the Stipulating Parties filed a motion in A.20-10-011 on April 13, 2022 to accept a joint stipulation on marginal generation capacity costs (April 13 joint stipulation) in lieu of testimony on the issue. The April 13 joint stipulation is identified as Exhibit PG&E-25 in A.20-10-011 and Exhibit PG&E-RTP-8 in A.19-11-019.

The April 13 joint stipulation recommended that the Commission adopt the MGCC study's methodology for calculating an hourly marginal generation capacity cost signal. It asserted that the MGCC study was a result of "a collaborative, [consensus-based] research effort spanning five months after initial data collection, with 21 meetings held between October 18, 2021 and March 10, 2022. MGCC Study Participants devoted considerable resources to addressing the following issues:

- Finding and vetting historical load and generation data
- Vetting AWE data from the [CAISO]
- Finding and vetting forecast data concerning load, generation and various measures of grid stress in outputs from the Energy Division's [SERVM data]
- Finding the historical measures of net load that best correlate with AWE data
- Examining the nexus between [a marginal generation capacity cost] signal and customer communications related to CAISO-declared AWEs."[14]

[14] Exhibit PG&E-25 in A.20-10-011 at 3-4.

With respect to the potential bill impacts of the MGCC study's proposed methodology, the April 13 joint stipulation repeats the findings of the MGCC Study itself, claiming that:

- Customers are unlikely to experience a substantial increase in interannual bill volatility after migrating to a real-time pricing rate from their Otherwise Applicable Tariff (OAT)
- A prototypical customer is likely to experience similar average bills under a real-time pricing rate and their OAT without load shifting
- A prototypical customer is likely to experience lower bills assuming battery operation or price-induced load shifting
- The recommended marginal generation capacity cost price signal formula provides greater profit opportunities for batteries compared to OAT.[15]

3.3. Reasonableness of the MGCC Study's Approach

Given the consensus-derived results provided by various intervenors and PG&E, that are uncontested, it is apparent that the MGCC study reflects a cross-party consensus for calculating a marginal generation capacity cost price signal for PG&E's approved real-time pricing rates, and that it is the result of months of diligent work by the Stipulating Parties. As recited above, there is ample record in both the MGCC study and the April 13 joint stipulation to support the conclusion that it is reasonable to adopt the MGCC study's methodology. In particular, the fact that the MGCC study's methodology: 1) would result in a marginal generation capacity cost signal that leads to non-zero prices at lower adjusted net loads, 2) places a cap on the hourly price component (rather than increasing indefinitely at higher and higher net loads),

[15] Exhibit PG&E-25 in A.20-10-011 at 7.

3) leads to lower year-to-year revenue variability, which should lower the likely magnitude of revenue over- and under-collections, 4) is not expected to have a significantly adverse bill impact on participating customers, and 5) is uncontested among the parties to A.19-11-019 and A.20-10-011, leads the Commission to conclude that the MGCC study's methodology is reasonable and should be adopted.

PG&E shall adopt the methodology outlined in the MGCC study – attached to this decision as Attachment A – for use in calculating a marginal generation capacity cost price signal to use in its real-time pricing rate designs approved by this decision and D.21-11-017.

Furthermore, pursuant to the recommendation in the MGCC study, PG&E shall reconvene the MGCC study working group after initial evaluation of PG&E's real-time pricing rates is complete, and no later than October 1, 2025, to consider whether any revisions should be made to the marginal generation capacity cost hourly price signal methodology. Any other interested party to either A.19-11-019 or A.20-10-011 should be invited to participate. If that working group determines through consensus that any adjustments to the methodology should be made, PG&E should seek Commission approval of those changes either as part of a formal application or through a Tier 3 Advice Letter.

4. A.19-11-019 Outstanding Motions

This decision affirms all rulings made by the Administrative Law Judge (ALJ) in A.19-11-019. Any other outstanding motions in A.19-11-019 are denied.

5. Comments on Proposed Decision

The proposed decision of ALJ Patrick Doherty in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

6. Assignment of Proceeding

Genevieve Shiroma is the assigned Commissioner in A.19-11-019, Clifford Rechtschaffen is the assigned Commissioner in A.20-10-011, and Patrick Doherty is the assigned ALJ in both A.19-11-019 and A.20-10-011.

Findings of Fact

1. The terms of the RTP settlement are compromise positions between the various positions taken by the parties in their testimony.

2. The parties to the RTP settlement engaged in settlement negotiations for over one year, and the settlement is a product of those efforts.

3. The RTP settlement is consistent with relevant statutes, Commission decisions, and public policy, including the Rate Design Principles adopted by the Commission in D.15-07-001, and Stage 1 pilot residential rates are aligned with the Commission's cost-of-service, affordability, and customer acceptance principles.

4. The RTP settlement attempts to mitigate rate and bill impacts for residential customers by applying a year of bill protection to those customers' bills, and for both residential and commercial customers by capping the marginal generation capacity cost price signal in the rate.

5. The RTP settlement proposes to test real-time pricing rate designs with the intent of reducing peak capacity costs faced by PG&E, and thereby reducing peak rates for all customers.

6. For both the real-time pricing rates approved as part of the RTP settlement in A.19-11-019, and the real-time rates already approved by the Commission in

D.21-11-017, it is necessary for the Commission to adopt a methodology for calculating the marginal generation capacity cost price signal in those rates.

7. The heart of the MGCC study served by the Stipulating Parties is a proposed methodology to calculate an hourly price signal for PG&E's new real-time pricing rates that is based on an hourly calculation of PG&E's marginal generation capacity costs.

8. The hourly marginal generation capacity cost price signal proposed by the MGCC study would increase greatly during times of severe grid utilization, subject to a cap on the maximum rate to be charged, based primarily on the adjusted net load that is forecasted by CAISO the day ahead for a given hour the following day.

9. Some of the benefits of the recommended marginal generation capacity cost pricing formula are: non-zero MGCC price signals at lower adjusted net loads, a maximum hourly marginal generation capacity cost price component (rather than increasing indefinitely at higher and higher net loads), and lower year-to-year revenue variability, which should lower the likely magnitude of revenue over- and under-collections.

10. The MGCC study recommended that the working group that produced the study be reconvened in the future, once evaluation of PG&E's real-time pricing rates has been completed, to re-evaluate the marginal generation capacity cost pricing formula.

11. No party to either A.19-11-019 or A.20-10-011 objected to the marginal generation capacity cost pricing methodology and proposal as described in the MGCC study.

12. The MGCC study reflects a cross-party consensus for calculating a marginal generation capacity cost signal for PG&E's approved real-time pricing rates, and it is the result of months of diligent work by the Stipulating Parties.

13. The MGCC study's methodology would result in a marginal generation capacity cost signal that leads to non-zero prices at lower adjusted net loads, places a cap on the hourly price component (rather than increasing indefinitely at higher and higher net loads), leads to lower year-to-year revenue variability, which should lower the likely magnitude of revenue over- and under-collections, and is not expected to have a significantly adverse bill impact on participating customers.

Conclusions of Law

1. The RTP settlement is reasonable in light of the whole record.

2. The RTP settlement is consistent with the law.

3. The RTP settlement is in the public interest.

4. The RTP settlement should be approved by the Commission.

5. It is reasonable to adopt the MGCC study's methodology for calculating a marginal generation capacity cost price signal for PG&E's real-time pricing rates.

6. It is reasonable to consider whether any revisions should be made to the marginal generation capacity cost hourly price signal methodology after initial evaluation of PG&E's real-time pricing rates.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall implement the provisions of the settlement on real-time pricing issues filed on January 14, 2022 in the docket of Application 19-11-019 as soon as practicable.

2. Pacific Gas and Electric Company shall adopt the methodology outlined in the marginal generation capacity cost study – attached to this decision as Attachment A – for use in calculating a marginal generation capacity cost price signal to use in its real-time pricing rate designs approved by this decision and Decision 21-11-017 as soon as is practicable.

3. Pacific Gas and Electric Company (PG&E) shall reconvene the marginal generation capacity cost study working group after initial evaluation of PG&E's real-time pricing rates is complete, and in any event no later than October 1, 2025, to consider whether any revisions should be made to the marginal generation capacity cost hourly price signal methodology.

4. Application 19-11-019 is closed.

This order is effective today.

Dated _________________, at Sacramento, California.