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Date: October 29, 2025
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023 GENERAL RATE CASE PHASE II

SUPPLEMENTAL TESTIMONY

EXHIBIT (PG&E-5)

REAL-TIME PRICING PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE PHASE II
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A. Introduction

Pacific Gas and Electric Company (PG&E) presents this Supplemental RTP Testimony (Testimony) in its 2023 General Rate Case Phase II (GRC II) Application (A.) 24-09-014,[1] as ordered by the California Public Utilities Commission's (Commission or CPUC) Decision (D.) 25-08-049 (DFOIR Track B Decision). In that Decision, the Commission ordered PG&E to, within 60 days of the final decision's issuance, serve supplemental testimony in this docket to comply with the Commission's guidance on how the California Energy Commission's (CEC) Load Management Standard (LMS) should be reflected in the Investor-Owned Utilities' (IOU) rate design proposals for Demand Flexibility Rates which PG&E will refer to in this testimony as Real-Time Pricing (RTP) rates.[2] Specifically, the Commission's new RTP rate design guidance relates to Marginal and Non-Marginal Costs, RTP Rates, and Export Compensation, Customer Protection Options, Equity and Access, and Load Serving Entity (LSE) Participation.[3]

This Testimony presents a revised and expanded showing for PG&E's RTP rate design proposals that were originally provided in A.24-09-014 as part of Exhibit PG&E-3 (Revenue Allocation and Rate Design), Chapter 10, as well as related Implementation and Marketing, Education & Outreach (ME&O) proposals

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,[1] A.24-09-014,General Rate Case Phase II Application of Pacific Gas and Electric Company, PG&E-3, Chapter 10, Real-Time Pricing and Load Management Standard Requirements.

[2] Please note that PG&E uses the term "Real Time Pricing" or RTP in this Testimony to refer to rates that are generally forecasted on a day-ahead basis and provide distinct pricing for each hour. These rates may also include prices that are made available in advance to customers, say a week ahead, to enable customers to lock in future prices through transactive pricing structures.

[3] D.25-08-049, Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals, R.22-07-005.

as part of Exhibit PG&E-3, Chapter 11. Additional chapters have been incorporated here to address the expanded showings required in the Commission's new guidance in the DFOIR Track B Decision. This Testimony is submitted as Exhibit 5 in A.24-09-014. A summary of Exhibit 5's contents and PG&E's key proposals presented in this exhibit is provided in the following section.

B. Summary of Exhibit Contents, Key Proposals, and Compliance with Requirements

Section B.1 below provides an overview of the exhibit contents. Section B.2 summarizes at a high level the key proposals presented in this exhibit. A table with compliance requirements relevant to this exhibit is shown in Attachment A of this Chapter 1.

1. Exhibit Summary

Table 1-1, below provides a summary of what is covered in each chapter of this exhibit.

TABLE 1-1
EXHIBIT 5 - SUMMARIES OF CHAPTER CONTENTS

Line No.	Chapter and Title	Summary of Chapter Content
1	Chapter 1 Introduction: RTP Regulatory Background; Experience With RTP Pilots; And Related Policy Issues, Including Dual Participation	Provides an overview of regulatory and pilot activities related to RTP Rates that have shaped PG&E's current RTP proposal. Also provides considerations related to dual participation of customers participating in both RTP Rates and Demand Response programs.
2	Chapter 2 Real Time Pricing and Load Management Standard Requirements	Presents proposed updated rate designs, incorporating guidance from the DFOIR Track B Decision.
3	Chapter 3 Community Choice Aggregator Collaboration	Presents PG&E's plan to collaborate with and seek feedback from CCAs in PG&E's service territory on RTP rate and program design.
4	Chapter 4 Regulatory Roadmap for RTP Implementation and Cost Recovery	Presents PG&E's proposed RTP Regulatory Roadmap for determining post-pilot RTP deployment, including rate design, operational implementation, M&E, ME&O and cost recovery. Requests authorization to submit a proposal in January 2026 to extend PG&E's Hourly Flex Pricing (HFP) Pilots until post-pilot RTP rates can be built in PG&E's billing system (Stop-Gap Interim RTP Pilot Proposal). Also requests authorization to present cost estimates for post-pilot RTP deployment in a Q3 2027 Updated Supplemental RTP Testimony, incorporating any guidance from the Enhanced Demand Response Order Instituting Rulemaking (EDROIR) in R.25-09-004, as well as learnings from PG&E's HFP Pilots.

2. Summary of Key Proposals

PG&E's key proposals found in this Testimony are summarized below by topic area:

a. Rate Design (Chapter 2)

PG&E created rate designs to comply with the DFOIR Track B Decision's requirement to submit rate design testimony within 60 days. These rate designs represent PG&E's best effort based on available information and analysis within this timeframe. The main features of PG&E's RTP rates proposed in this Supplemental RTP testimony include:

- A day-ahead hourly generation rate for bundled customers designed to collect Marginal Energy Costs (MEC), line losses, and Marginal

Generation Capacity Costs (MGCC). For unbundled customers, Community Choice Aggregators (CCA) will have the option to customize the coefficients of the MEC, line loss (for generation), and MGCC formulas and/or apply a modifier.

- A day-ahead hourly distribution rate designed to collect primary distribution capacity costs. The hourly prices will vary depending on the location of the customer and will be determined using the scarcity pricing concept, with prices dependent on the forecasted load on a representative circuit with similar load characteristics to the customer's circuit. It will use a sigmoidal pricing function similar to that used for PG&E's CPUC-adopted MGCC.[4]
- A transmission rate equal to the transmission rate on the customer's Otherwise Applicable Tariff (OAT) until a different dynamic version is approved at the FERC.[5]
- Non-marginal costs will be added to the RTP Rates for delivered energy in order to make them revenue neutral to retail rates. This will take the form of a revenue neutral adder (RNA) that will vary by rate schedule.
- An optional subscription component that collects revenue equal to the OAT rates applied to a predefined, customer-specific load profile. This component helps protect the customer from bill volatility because the dynamic components are only applied to deviations from this load profile.

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4 D.22-08-002. Marginal Generation Capacity Cost Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates, Report to Parties in California Public Utility Commission Dockets A.20-10-011 and A.19-11-019

5 PG&E is currently researching and developing what should go into an hourly transmission rate component. As outlined in PG&E's LMS Compliance Plan which was approved in May 2025, substantial research still needs to be done to design a dynamic transmission signal that accurately reflects the scarcity concept. PG&E's current plan is to propose an hourly transmission rate component to the Federal Energy Regulatory Commission (FERC) in Q3 of 2026, for implementation on January 1, 2027. PG&E's Revised Compliance Plan for the LMS (Jan. 9, 2025),CEC Docket No. 23-LMS-01, TN# 262235 (docketed Mar. 18, 2025), available at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-lms-01> (accessed Oct. 7, 2025).

b. CCA Collaboration (Chapter 3)

PG&E has been collaborating with the CCAs in regularly scheduled monthly meetings and weekly office hours on RTP Rates since the August 2022 Decision approving Day-Ahead Hourly RTP.[6] PG&E plans to continue this collaboration, focusing on:

1. RTP rate design topics, including generation, distribution, customer bill protection, subscription design, and transactive options.[7]
2. Facilitating understanding by the CCAs of PG&E's program design, including target segments and technologies, Marketing, Education and Outreach (ME&O) plans, the Automation Service Provider engagement model, compensation, technology incentives, and customer support.
3. Sharing lessons learned from the RTP Pilots and ME&O efforts to foster customer understanding of both bundled and unbundled DF rate offerings.

The outcomes of these discussions will help PG&E shape the post-pilot RTP proposal that we plan to present in the Q3 2027 Supplemental Testimony Update shown in the following section and described in more detail in Chapter 4 of this exhibit.

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[6] D.22-08-002 approved RTP Pilots for residential, commercial and industrial customers on the E-ELEC, B-6 and B-20 rates. Those pilots were ultimately replaced by the Expanded Pilots in D.24-01-032. PG&E has an outstanding Petition for Modification to remove the requirements of D.22-08-002.

[7] PG&E's DF rate design proposal conforms with the CEC's LMS requirements as reflected in the CPUC's Guidance Decision in the DFOIR Track B Decision (D.25-08-049), however it is at the discretion of each of the CCAs Boards whether to adopt the same rate design used for PG&E, and/or ensure that their own rate design conforms with their CEC-approved LMS plan.

c. RTP Regulatory Roadmap for Implementation and Cost Recovery (Chapter 4)

PG&E will be filing a Motion in this proceeding by November 17, 2025, regarding the Bifurcated RTP Track schedule[8] that requests an expedited Ruling approving PG&E's RTP Regulatory Roadmap's schedule for two additional filings, as detailed in Chapter 4, Section F and summarized as follows:

1) Stop-Gap Interim RTP Pilot Testimony – Requested RTP Regulatory Roadmap Timing

a) 1/31/26 – PG&E's Stop-Gap Interim RTP Pilot Proposal to extend our ongoing HFP Pilots beyond their current December 31, 2027, expiration date.

b) 11/19/26 – Requested target date for CPUC issuance of a final Decision on PG&E's Stop-Gap Interim RTP Pilot proposal to provide enough time to make the adopted modifications for the extension of the HFP Pilots beyond December 31, 2027.

2) Updated Supplemental RTP Testimony – Requested RTP Regulatory Roadmap Timing

a) Q3 2027 – PG&E's Updated Supplemental RTP Testimony submitted, using the most informed rate design and Operational Implementation, M&E and ME&O plans as possible incorporating learnings from the HFP Pilots mid-term M&E results, available August 2026, as well as incorporating guidance from the EDROIR final decision expected by the end of 2026.

b) 12/31/28 – Requested target date for CPUC issuance of a separate final Decision on both this Supplemental RTP Testimony (submitted 10/29/25), and on PG&E's Updated Supplemental RTP Testimony (to be submitted in Q3 2027) to allow enough time to implement the adopted modifications for post-pilot RTP deployment.

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[8] The schedule for these two proposed additional submissions will be included in the Motion presenting scheduling proposals for the bifurcated track for Dynamic Rates due no later than November 17, 2025. Administrative Law Judge's Ruling Modifying Schedule and Setting a New Track for Dynamic Rate Options (Oct. 9, 2025) (ALJ Atamturk Ruling) p. 4, Ordering Paragraph (OP) 3). Note that this testimony was finalized before the required Motion's proposed scheduling options had been completed.

If the CPUC does not approve the January 2026 Stop-Gap Interim Pilot Proposal or the Q3 2027 Updated Supplemental RTP Testimony elements of our RTP Regulatory Roadmap, PG&E requests that the CPUC issue an interim decision: (1) authorizing PG&E to file a Tier II advice letter to continue the HFP pilots after December 31, 2027, until PG&E's Billing Modernization Initiative (BMI) is completed and RTP rates are built in the billing system, and (2) establish the schedule and/or proceeding for further testimony on post pilot RTP rates and related processes and system costs.

Finally, PG&E summarizes various compliance-related activities which are presented in Exhibit PG&E-5, Chapter 1, Attachment A.

C. Organization of the Rest of This Chapter and Witness Responsibilities

The remainder of this chapter is organized as follows:

- Section D – RTP Regulatory Background
  - Provides a summary of the regulatory activities and the RTP pilots that have informed PG&E's 2023 GRC II RTP proposal presented in Chapter 2;
- Section E – Other Policy Considerations: Dual Participation
  - Discusses PG&E's recommendations on how dual participation on RTP Rates and Demand Response programs should be addressed in the EDROIR proceeding.
- Section F – Organization of This Exhibit
  - Lists how Exhibit PG&E-5 is organized.

The witness responsibilities for this chapter are as follows:

- Melanie McCutchan – All Sections, except Section E: Other Policy Considerations: Dual Participation
- Neda Assadi – Section E: Other Policy Considerations: Dual Participation

D. RTP Background

RTP Rates have been considered across a number of separate CPUC regulatory proceedings, not only in rate making proceedings but also in rulemakings related to reliability and transportation electrification. RTP rate offerings are currently being tested in pilots that have been developed through these proceedings. Additionally, in the CEC's LMS Rulemaking, the CEC has presented the CPUC with its guidance related to future RTP Rates, while recognizing that the CPUC holds the ratemaking authority for the IOU's. A CPUC staff whitepaper and a working group established through the CPUC's DFOIR Track B have also generated thought leadership and input on RTP rate design, which has culminated in a DFOIR Track B Final Decision (D.25-08-049) that provided guidance to which this Testimony responds. The DFOIR Track B Decision, however, did not address key issues that were originally in scope of the DFOIR Track B Decision, but will be addressed in subsequent rulemakings.[9] These issues included what systems and processes should be in place to support implementation of RTP Rates, and considerations of costs. In September 2025, the CPUC opened an EDROIR (R.25-09-004) which incorporated scope related to RTP and addressing elements of the CEC's LMS requirements that had originally been part of the Demand Flexibility Track B rulemaking on systems and processes to support RTP.[10] PG&E believes guidance from the EDROIR will be critical to informing a final implementation and ME&O plan before post-pilot RTP deployment.

This section attempts to organize chronologically the many regulatory developments and RTP pilot activities that both reflect and have shaped policy makers, stakeholders, and PG&E's positions on RTP over the past six years. Please note, however, that some of these regulatory developments and activities have overlapped in time. The proposed RTP rate design that is presented in Chapter 2 of this testimony was primarily shaped by the guidance provided in the DFOIR Track B Guidance Decision as well as learnings from the operation of PG&E's HFP and Phase II Vehicle to Grid (VGI) pilots that were launched in November and October 2024 respectively, as well as learnings from other ongoing or recently completed RTP pilots in California.

Readers who are already familiar with the longer-term history of RTP may wish to go directly to sections D.11 and D.12 of this Chapter, which focus on the DFOIR Track B Rulemaking and Final Decision guidance, and the recently opened EDROIR, respectively. In Section D.13, PG&E also presents initial

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9 D.25-08-049, p.13.

10 The IOUs submitted their Track B, working group 2 report on systems and processes in R. 22-07-002, on October 11, 2023, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K541/520541672.PDF> (accessed Oct. 21, 2025).

learnings from our RTP Pilots that have shaped PG&E's revised RTP proposal that is presented in Chapter 2. Additional discussion of key learnings from a given RTP pilot are presented in Sections 4.a (VCE AgFIT pilot), Section 4.b (SCE Dynamic Rate Pilot), Section 6 (Phase II of PG&E's VGI Pilots), Section 7 (SDG&E EV Charging RTP Pilot), and Section 11.d (PG&E HFP Pilots[11]).

Table 1-2 shows the key developments related to RTP Rates that are further described in the remainder of this section.

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11 In this testimony, PG&E refers to RTP rates adopted in its Expanded Pilots from D.24-01-032 as Hourly Flex Pricing (HFP) Pilots.

TABLE 1-2
SUMMARY OF REGULATORY DIRECTIVES AND ACTIVITIES RELATED TO RTP OVER THE PAST SIX YEARS

Line No.	Year	Rulemaking/ Guidance/Activity	Key Outcomes
1	2019	D.19-03-002 in response to Joint Petitioners' request for a Ruling to consider RTP Rates.	CPUC affirms that RTP Rates may be considered in PG&E, SDG&E, and SCE's subsequent GRCs.
2	2020-2022	D.22-08-002 in PG&E's GRC II Application (A.) 19-11-019 approves settlement agreement for PG&E RTP Rates.	CPUC approved three new "Stage 1" PG&E RTP pilots, based on Day-Ahead Hourly Real Time Pricing (DAHRTP) signals: 1. DAHRTP Large Commercial for customers taking service on B-20, 2. DAHRTP Small Commercial for customers taking service on B-6,and 3. DAHRTP Residential for customers taking service on E-ELEC.
3	2021	Rulemaking (R.) 20-11-003 on Summer Reliability Issues and D.21-12-015.	The CPUC authorized two additional RTP pilots: 1. Agricultural Water Pumping Real-Time Pricing Pilot (AgFIT) proposed by Valley Clean Energy (VCE), approved as a Demand Response Emerging Technologies Pilot, and 2. RTP Pilot for Residential, Commercial and Industrial customers in SCE's service area (SCE Dynamic Rate Pilot).
4	2019-2022	PG&E's Application for a "Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot," A. 20-10-011 and D.21-11-017, D.22-08-022, D.22-10-024, D.20-12-029, CPUC Res.E-5192.	The CPUC authorized four new RTP offerings for commercial customers with Electric Vehicle (EV) charging equipment, with day-ahead price signals: 1. DAHRTP Business Electric Vehicle (BEV) Opt-In Rate for customers taking service on PG&E's BEV Rate, 2. DAHRTP BEV Export Pilot which set compensation for exports to the grid, 3. VGI Phase II Pilot 1 for Residential Customers, and 4. VGI Phase II Pilot 2 for Commercial Customers.
5	2021	CEC proposes amendments to its LMS in Docket 21-OIR-03.	Marginal cost rates that change hourly (RTP Rates) are included in LMS scope.
6	2022	CPUC DER Action Plan 2.0.	The Action Plan included a "Vision Element" to enable access to RTP for all customer classes by 2025.

TABLE 1-2
SUMMARY OF REGULATORY DIRECTIVES AND ACTIVITIES RELATED TO RTP OVER THE PAST SIX YEARS
(CONTINUED)

Line No.	Year	Rulemaking/ Guidance/Activity	Key Outcomes
7	2021-2023	CEC Proposes (Oct 2022) and Adopts (Apr 2023) LMS Amendments	Orders IOUs to submit RTP Rates to their rate-approving bodies by January 2025 and make RTP Rates available to all customers classes by January 2027.
8	2022	CPUC Energy Division Staff White Paper introduces California Flexible Unified Signal for Energy (CalFUSE) as a proposed framework for dynamic rates.	CalFUSE framework outlines key considerations for RTP rate design.
9	2022-2024	CPUC DFOIR (R.22-07-005)	CPUC issues revised Rate Design and Demand Flexibility Principles in D.23-04-040. CPUC adopts HFP Pilot 1 (Ag) and 2 (Res, C&I) in D.24-01-032.
10	Sep 2024	PG&E RTP Proposal in 2023 GRC Ph. II A.24-09-014	PG&E submits its initial RTP proposal as part of its 2023 GRC Ph. II application to comply with the CEC LMS Directive to submit RTP Rates by January 1, 2025.
11	Aug 2025	DFOIR Track B Final Decision (D.25-08-049)	CPUC Issues a Final Decision in DFOIR Track B (Scoping issues 1-3) which provides guidance on RTP Rate Design, indicated Scoping Issues 4-6 on systems and processes will be handled in another Rulemaking, closes DFOIR.
12	Sep 2025	EDROIR (R.25-09-004)	CPUC opens EDROIR which is expected to address RTP rate systems and processes from DFOIR Track B, dual participation, and other policy issues.

1. Time-Varying Rates – Pre-2019

The CPUC has a long history of support for time-varying electricity rates, driven by the goal of achieving more flexible load to support electric system needs. PG&E has been actively engaged in these efforts and submitted numerous proposals pertaining to time-varying rates. Large Commercial and Industrial (C&I) customers have had experience with time-of-use (TOU) rates since the late 1970's or early 1980's, depending on the size of the customer.[12] These TOU rates, which provided varying pricing based on the time of day, were enabled by special interval meters that had the ability to measure electricity usage on hourly intervals.

Nearly two decades ago, the CPUC approved the deployment of Advanced Metering Infrastructure (AMI), consisting of more modern interval meters that can record usage on a temporally granular level—generally hourly—and communicate that information to the Utility.[13] AMI has been adopted widely across more customer sectors among PG&E's customer population, including Small Commercial, Agricultural, and Residential customers, which enabled TOU rates for these customer groups. Currently, approximately 99.1 percent of PG&E's customers are billed through AMI interval data. Building on AMI adoption and customer experience with TOU rates, the CPUC has further considered more dynamic time-varying rates in subsequent proceedings.

2. Joint Petitioners – 2019

In March 2019, the CPUC issued D.19-03-002 in response to Petition (P.) 18-11-004 submitted by the Joint Petitioners.[14] This Petition requested that the CPUC open a Rulemaking to consider RTP and other rate design proposals, and asked that the CPUC consider whether to order California's three large IOUs to offer RTP Rates to all customer classes. In D.19-03-002, the CPUC denied this Petition on procedural grounds, but

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12 D.08-07-045, p. 10.

13 D.06-07-027.

14 Consisting of the California Solar and Storage Association (CALSSA), California Energy Storage Association, Enel X North America, Inc. (Enel X), ENGIE Services, ENGIE Storage, OhmConnect, Inc., Solar Energy Industries Association, and STEM, Inc.

affirmed that RTP Rates may be proposed and considered in PG&E, SDG&E, and SCE's GRC Applications.[15]

3. PG&E's 2020 GRC – 2020-2022; DAHRTP Stage 1 Pilots

PG&E's 2020 GRC II Application (A.19-11-019) opened in late 2019. In August 2020, an Administrative Law Judge (ALJ) Ruling in this proceeding encouraged PG&E and other parties to present their proposals for RTP Rates. In November 2020, the Agricultural Energy Consumers Association (AECA), Joint Advanced Rate Parties,[16] and Small Business Utility Advocates (SBUA) submitted testimony in PG&E's GRC II proceeding that included proposals related to RTP rate design. In Supplemental Testimony submitted in March 2021, PG&E proposed an RTP Pilot for Large C&I customers taking service on rate Schedules B-19 and B-20.[17] PG&E also proposed to conduct further customer research to better understand RTP preferences among residential and agricultural customers. The recommendation for this additional research was driven by benchmarking review of other United States utilities' RTP programs which found limited experience with RTP Rates among residential and agricultural customers.[18]

A settlement agreement was signed by PG&E and interested parties in A.19-11-019,[19] which the CPUC approved in August 2022 through D.22-08-002. Per this settlement, optional hourly RTP generation rates with a Revenue Neutral Adder (RNA)[20] were approved, not only for Large C&I customers taking service on Schedule B-20, but also for Small Commercial

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15 D.19-03-002, p. 9.

16 The Joint Advance Rate Parties included CALSSA, Enel X, and OhmConnect.

17 A.19-11-019, Exhibit (PG&E-RTP-1), p. 4-1, lines 14-16.

18 A.19-11-019, Exhibit (PG&E-RTP-1), Appendix A. The Benchmarking Study of U.S. Regulated Utility Real Time Pricing Programs, Architecture and Design, Electric Power Research Institute, Final Report, March 2021. This study was also summarized in Exhibit (PG&E-RTP-1), Ch.2.

19 Per D.22-08-002, pp. 4-5, the settlement parties included: AECA, California Large Energy Consumers Association, the CALSSA, Enel X, Energy Producers and Users Coalition, Federal Executive Agencies, Public Advocates Office at the California Public Utilities Commission, and SBUA.

20 The RNA is a non-time-varying cents per kilowatt-hour (¢/kWh) amount that is added to the hourly price to ensure that non-marginal costs applicable to the otherwise applicable rate schedule are also collected. The dynamic price typically only includes marginal costs, while the RNA typically contains non-marginal costs.

customers taking service on Schedule B-6 and Residential customers taking service on PG&E's Schedule E-ELEC rate plan.[21] These DAHRTP "Stage 1 Pilots" could be followed by pilots for additional rate schedules once the Stage 1 Pilots were begun.[22] The opt-in Stage 1 DAHRTP pilots adopted in D.22-08-002 included hourly price signals based on California Independent System Operator (CAISO) day-ahead market wholesale prices, with a capacity adder.[23] The Stage 1 Pilots only included a day-ahead hourly *generation* rate and did not include a *distribution* or *transmission* RTP price component. The Stage 1 DAHRTP Pilots were limited to generation because a generation price signal was viewed as providing the most value in terms of a load management signal. Location-specific distribution RTP price components could be developed later once further experience and learnings were gained through the Pilot. For these Pilot rates, the RTP generation component would replace the generation component of the customer's OAT rate schedule and would include MEC, MGCC, and an RNA. Transmission and distribution cost components, as well as Public Purpose Program and other charges and taxes, would remain the same as those in the customer's OAT.[24]

The RTP rate Pilots approved in D.22-08-002 (DAHRTP Stage 1 Pilots) were initially scheduled to roll out in October 2023. On April 26, 2023, the Commission's Executive Director granted PG&E's request for an extension to February 28, 2024. On November 14, 2023, PG&E requested an additional extension to February 28, 2025. This requested extension was due to delays experienced in PG&E's multi-year Billing Modernization Initiative (BMI). The delay also made sense because the CEC had, effective April 2023, amended the LMS. The CEC's LMS recommendations were amended to include that RTP Rates should include not only an hourly *generation* rate component—which PG&E's DAHRTP Stage 1 Pilots were to include—but also hourly *distribution* and *transmission* price signals (which

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21 D.22-08-002, p. 5; p. 25, OP 1.

22 D.22-08-002, p. 5.

23 D.22-08-002, p. 17. A capacity adder reflects the cost of maintaining adequate resources to meet system reliability needs.

24 D.22-08-002, p. 7.

are not included in PG&E's DAHRTP Stage 1 Pilots).[25] The LMS also directed PG&E and other California IOUs to submit LMS-compliant rates to the CPUC by January 1, 2025[26] and make those rates available to all customer classes by January 2027.[27]

PG&E maintains that the generation-only rates being tested in the ongoing DAHRTP Stage 1 Pilots should not ultimately be implemented, given that the DAHRTP Stage 1 Pilot rates: (1) did not include the CEC's amended LMS requirement,[28] that RTP Rates should also include a distribution and transmission dynamic price signal; and (2) are not consistent with the RTP rate design in the HFP Pilots approved in D.24-01-032 (See Section D.11.d of this chapter). Instead, the DAHRTP Stage 1 Pilot eligible customers should be allowed to participate in PG&E's HFP Pilots[29] which include hourly RTP Rates for both generation and distribution and allow participation for similar customer segments, Large C&I, Small Commercial and Residential.[30] On March 3, 2025, PG&E was granted a further extension for the DAHRTP Stage 1 Pilots adopted in D.22-08-002 to February 28, 2026, or until the Commission rules on PG&E's petition to modify D.22-08-002.

4. Directives in Response to Summer Reliability; VCE AgFIT and SCE Dynamic Rate Pilot – 2021-Present

In response to rolling blackouts in August 2020, the CPUC opened a proceeding to address summer reliability challenges, R.20-11-003. In this

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25 20 CCR, § 1623(a)(1).

26 20 CCR, § 1623(a)(2).

27 20 CCR, § 1623(d)(2).

28 The CEC's LMS requirements establish guidance for hourly marginal cost-based RTP rates but also recognize that the CPUC ultimately must approve any RTP rate design for the electric IOUs, as well as assess implementation costs and approach, given the CPUC's exclusive jurisdictional authority over rate setting for the IOUs. See 20 CCR § 1621(g).

29 In February 2025, PG&E filed a Petition for Modification of D.22-08-002 (PFM) with an Amended Settlement, to make the appropriate changes in the decision. PG&E's PFM is awaiting a decision from the CPUC. The PFM can be accessed at the following link: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K603/556603718.PDF> and <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K602/556602509.PDF> (accessed Oct. 22, 2025).

30 D.24-01-032, p. 21.

Rulemaking, the Commission issued D.21-12-015 to authorize two reliability Pilots with RTP Rates: (1) the Agricultural Flexible Irrigation Technology (AgFIT) Pilot proposed by VCE, a CCA in PG&E's service area (VCE AgFIT Pilot)[31] and (2) an RTP pilot for Residential and C&I customers in SCE's service area (SCE Dynamic Rate Pilot).[32] Administration and evaluation of the VCE AgFIT pilot was funded under PG&E's Demand Response Emerging Technologies program authorized in D.17-12-003.[33]

a. VCE AgFIT Pilot

The objective of the AgFIT Pilot was to test the interest and ability of Agricultural customers to manage water pumping in response to RTP. The VCE AgFIT pilot included incentives for irrigation automation and scheduling software, as well as transactive forward pricing, a week-ahead hourly price available to participating customers. The generation price was determined by the CCA, and the distribution price signal was provided by PG&E, based on distribution circuit-level forecasts. The initial stage of the pilot also included a "subscription" option that provided bill protection for participating customers, as well as revenue collection protection for the generation Load-Serving Entity (VCE) and distribution service provider (PG&E).

The subscription level was based on the customer's historical usage. Usage below that subscription amount was credited at the RTP price, while incremental usage above the subscription amount was charged at the RTP price. This is illustrated in Figure 2-21 in Chapter 2 of this Testimony on Rate Design. The credits and charges were decremented or added to the amount the customer would owe—calculated based on the subscription level of usage and the customers' OAT—to determine the customer's bill in a given month. Under this structure, customers were only exposed to the RTP price for usage above or below their subscription level.

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[31] D.21-12-015, p. 89.

[32] *Id.* at p. 96.

[33] *Id.* at p. 87.

The VCE AgFIT Pilot contained a subscription only for its first year of operation. After the first year, the subscription based on usage was removed. Instead, a "price averaging" method was put in place, in which the forecasted prices for the coming week are all adjusted up or down, such that the average price over a two-week period is equal to the average actual retail price.[34] This change was done primarily because the pumping needs of the customers on the pilot varied significantly year-over-year. The standard subscription method did not work well when subscribed load was frequently above or below the actual load because customers would be charged retail rates on a load profile that was quite different from their actual usage and then be charged or credited for the difference on a dynamic rate. Customers were thus often underpaying or overpaying for electricity, relative to their cost of service.

Bill protection was provided in the VCE pilot through "shadow billing." With shadow billing, a customer's bill continues to be calculated as though the customer were on their OAT (a non-RTP rate) and a shadow bill is calculated based on the RTP rate. On a cumulative 12-month basis, customers are not responsible for paying more than they would have paid on their OAT but do receive credit if their shadow bill is lower under the RTP rate structure. The VCE AgFIT pilot was also designed with a transactive element that allowed participating Agricultural customers to see forecasted prices seven days out, and "lock in" the forecasted price for that day, at their option, which could facilitate scheduling irrigation pumping during lower cost hours. VCE was responsible for the generation RTP component and credit, while PG&E was responsible for the RTP distribution component and credit.

The VCE Pilot began providing RTP signals to customers in August 2022 and ran through the end of 2024. The RTP generation elements

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34 The price averaging method provides some insulation from high prices by ensuring that the average price over a two-week period remains constant. If extremely high prices are present, then the averaging mechanism either brings down the high prices and/or offers very low prices during other hours to mitigate the high price periods. Because all prices are shifted up or down by a constant factor, the within-day variation of the hourly prices is maintained.

were provided by VCE (the customers' CCA), while the RTP distribution elements were provided by PG&E. The customers enrolled in the Pilot were a mix of small, medium, and large Agricultural customers served by VCE that employ irrigation pumps to water different types of crops. Most customers enrolled in the pilot had multiple pumps (service accounts). Enrollment was:

- By September 2022: two customers with a combined total of 17 pumps.
- By September 2023, five customers with a combined total of 33 pumps.
- By September 2024, seven customers were enrolled with a total of 60 pumps.

The Final Evaluation report for the VCE AgFit pilot was issued in April 2025.[35] Key findings from the report were the following:

- Customers faced operational constraints in their ability to respond to price signals and adjust irrigation pumping load due to variability in weather conditions and other factors that affected pumping needs.[36]
- Load was at times highly responsive, but operational constraints meant that "one should not assume that a high percentage of the pumping load will be curtailed in response to a specific high-price event."[37]
- Automating pump operations supported customers' ability to respond to price signals.[38]
- Some customers were able to leverage transactive pricing to schedule pumping during lower price hours to achieve bill savings.[39]

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35 Hansen, D. and Clark, M., Christensen Associates, Final Evaluation of VCE's Agricultural Pumping Dynamic Rate Pilot (Apr. 17, 2025) (Final Evaluation of VCE's Pilot).

36 Final Evaluation of VCE's Pilot, pp. 2, 80.

37 Final Evaluation of VCE's Pilot, pp. 2, 80.

38 Final Evaluation of VCE's Pilot, pp. 2, 81.

39 Final Evaluation of VCE's Pilot, pp. 2, 81.

- The shadow bill credit method, with bill protection, confounded evaluation of load response, as at least some customers managed load to their OAT rather than the hourly dynamic price.[40]
- While two of the participating customers showed statistically significant price response during the VCE pilot, the evaluators found it difficult to attribute load response to the RTP price. This was due to the incentive that customers retained, under the shadow billing structure, to respond to their OAT price to avoid increasing their OAT bill, rather than the dynamic price.[41]
- Subscriptions can create structural winners and losers for customers whose load factors vary considerably from year to year.[42]

b. SCE Dynamic Rate Pilot

In D.21-12-015, the CPUC approved a different pilot, run by Southern California Edison (SCE), which was formally approved under the name the "SCE Dynamic Rate Pilot." also known as "The [SCE] Flexible Pricing Rate Pilot." This Pilot allows SCE Residential and Non-Residential customers with select devices—such as programmable communicating thermostats, energy storage devices, or an EV—to participate in the pilot, which ran from 2022-2024. SCE's Pilot included both a generation and distribution price signal and included 38 participants.[43] The Final Evaluation Report for SCE's Dynamic Rate Pilot, issued in February 2025, "did not find evidence of consistent and/or large changes in hourly energy usage due to customer price response."[44] That final evaluation study provided the following potential explanations for the lack of large or consistent changes in hourly energy usage:

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[40] Final Evaluation of VCE's Pilot, pp. 3, 82.

[41] Final Evaluation of VCE's Pilot, pp. 45-46.

[42] Final Evaluation of VCE's Pilot, pp. 3, 70-76.

[43] Hansen, et al., Christensen and Associates, Final Evaluation of Southern California Edison's Dynamic Rate Pilot (Feb. 28, 2025) (Final Evaluation of SCE's Pilot), p. 6, available at: <https://www.dret-ca.com/wp-content/uploads/2025/03/PUBLIC-SCE-DRP-Final-Evaluation-Report.pdf> (accessed Oct. 18, 2025).

[44] Final Evaluation of SCE's Pilot, pp. 7, 39-44.

- There was a delay in getting customers the pricing and billing feedback that might have helped them respond by modifying their load thereafter;
- Similar to the findings from the VCE AgFit evaluation report, the shadow billing construct may have led customers to focus more on managing their load/costs to the OAT rather than to the RTP rate; and
- Hourly price variability may not have been high enough to induce significant load response.[45]

Another finding from the study was that customer's subscription load profiles were the most important factor in determining whether a customer was due a shadow bill credit, rather than the customer's responsiveness to dynamic pricing. The report suggested that future research should address the optimal method for subscription pricing (e.g., whether/how to update quantities over time, how to deal with NEM and electric vehicle adoption).[46]

5. PG&E's Commercial EV RTP Rates Application; BEV RTP Rates – 2020-2022

Concurrent to the RTP Rates being considered in PG&E's 2020 GRC and the Summer Reliability proceeding (R.20-11-003), RTP Rates for EV charging were considered in PG&E's Application for a "Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot," (A.20-10-011). This EV RTP Application was informed by Senate Bill (SB) 676 (Bradford), which ordered PG&E and the state's other large IOUs to develop measures to achieve electric VGI integration targets set by the bill. The EV RTP Application was filed in response to D.19-10-055 (OP 9). In A.20-10-011, PG&E proposed hourly generation RTP Rates, but no other RTP rate elements because, as with the DAHRTP Pilots the CPUC approved in PG&E's 2020 GRC Phase II, the generation price signal was viewed as providing the most value in terms of a load management signal.[47] The two

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[45] Final Evaluation of SCE's Pilot, pp. 7-8.

[46] Final Evaluation of SCE's Pilot, pp. 54-55.

[47] A.20-10-011, Exhibit (PG&E-1), p. 2-15, lines 2-27.

rate options proposed, the DAHRTP BEV Opt-In Charging Rate and the DAHRTP BEV Non-NEM Export Pilot, are described below.

a. DAHRTP BEV Opt-In Rate

In A.20-10-011, PG&E proposed a dynamic rate option for commercial customers with EV charging infrastructure. The rate would have been open to customers enrolled on PG&E's Business Electric Vehicle (BEV) rate. Customers who would have participated in this opt-in rate would receive DAHRTP BEV pricing. As was the case with PG&E's Stage 1 Pilots approved through PG&E's 2020 GRC II proceeding, the DAHRTP BEV Opt-in Rate[48] was planned to include hourly marginal generation energy and capacity cost components, but no price signals associated with distribution and transmission costs. PG&E would have been responsible for providing the generation RTP rate component for bundled customers, while CCAs would have been responsible for providing the generation rate component for their unbundled customers.

PG&E's application for the proposed DAHRTP BEV Opt-In rate was approved in D.21-11-017 (OP 1), subject to a later decision on determining how to calculate the MGCC RTP cost component,[49] which was approved in D.22-08-002 (OP 2). The non-NEM export pilot for DAHRTP BEV customers was approved in D.22-10-024, but was dependent on implementation of the DAHRTP BEV Opt-In rate. However, the DAHRTP BEV Opt-In rate is not compliant with the more recent CEC LMS guidance requesting the CPUC to consider rate designs that include dynamic price components that also reflect distribution and transmission costs, in addition to generation costs. The DAHRTP BEV Opt-In rate implementation was originally scheduled for Q4 2023,[50] but was extended to February 28, 2024, by the Executive

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[48] This rate option has also been referred to as the "DAHRTP CEV Opt-in Rate" where CEV stands for Commercial Electric Vehicles. We will refer to rate as the "DAHRTP BEV Opt-In Rate" to reflect the underlying BEV rate on which customers must take service.

[49] D.21-11-017, p. 40.

[50] AL 6506-E, p. 10.

Director in a letter dated April 23, 2024. On February 20, 2024, PG&E requested an additional extension to February 28, 2025, which the Executive Director granted on February 28, 2024. The following year, on February 20, 2025, the implementation deadline for the DAHRTP BEV Opt-In rate and Non-NEM Export Compensation Pilot was extended to February 28, 2026, or until the Commission rules on PG&E's petition to modify D.21-11-017.

Instead of launching a separate DAHRTP BEV Opt-In rate, PG&E has extended to all BEV customers eligibility for Phase II of the VGI Pilot 2. Under Phase II of the VGI Pilot 2 rate, as discussed in Section D.6 of this Chapter, customers are exposed to generation *and distribution* RTP pricing, which is more in line with the CEC's LMS requirement, discussed in Section D.9 of this chapter. PG&E has requested that the CPUC's prior requirement for a separate DAHRTP BEV Opt-In rate be lifted[51] since PG&E made RTP generation and distribution rates available to BEV customers through Phase II of the VGI Pilot 2.

b. Non-NEM Export Pilot for DAHRTP BEV Customers

The DAHRTP BEV Opt-in Rate described above was intended to provide RTP price signals for usage from the grid (imports or electricity delivered to customers) but was not designed to provide compensation for exports to the grid. In D.22-10-024, the CPUC resolved whether and how to establish export compensation rules for PG&E customers taking service on the DAHRTP BEV Opt-in Rate through approval of a settlement between PG&E and intervening parties to the proceeding. Net Energy Metering (NEM) and Net Billing Tariff (NBT) customers already receive compensation for exports to the grid from on-site renewable generation, for example, rooftop solar. NEM and NBT customers are eligible for compensation under the NEM and NBT tariffs, and to get that compensation, cannot export stored electricity that was

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51 In February 2025, PG&E filed a Petition for Modification of D.21-11-017 (PFM) to modify the decision to remove the requirement to offer the DAHRTP BEV opt-in rate. The PFM is awaiting Commission decision. The PFM can be accessed at the following links: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K961/555961266.PDF> and <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K391/556391106.PDF> (accessed Oct. 22, 2025).

imported from the grid, back to the grid. Thus, the export compensation mechanism for customers on the DAHRTP BEV Export Pilot rate would be applicable only to non-NEM and non-NBT export compensation.

For this Non-NEM Export Pilot for DAHRTP BEV customers, exports were to be compensated at the MEC and MGCC, not including the RNA. As with PG&E's DAHRTP Stage 1 Pilots described in Section D.3 of this chapter, the design of the BEV Non-NEM Export Pilot did not include cost components associated with distribution and transmission services in the RTP price signal and was thus not consistent with the guidance set forth in the CEC's LMS. PG&E would have been responsible for the entire non-NEM export compensation for bundled customers, while CCAs would have been responsible for the generation portion of non-NEM export compensation for their unbundled customers.

PG&E has not yet launched the Non-NEM Export Pilot, due to interdependence with the DAHRTP BEV Opt-In rate which PG&E does not plan to pursue and instead has offered participation in the Phase II VGI Pilots described in Section 6 of this chapter. PG&E currently allows RTP compensation for exports during Phase II of the VGI Pilots, for eligible BEV customers (with bidirectional equipment interconnected under Rule 21).

6. DRIVE Rulemaking (R.18-12-006) and PG&E VGI Pilots – 2020-Present

SB 676 (Bradford, 2019) ordered PG&E and the state's other large IOUs to develop measures to achieve VGI targets set by the bill. In R.18-12-006, the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE) Rulemaking, the CPUC issued D.20-12-029, which encouraged PG&E and the other large IOUs to submit pilot proposals to support VGI.[52] PG&E proposed VGI Pilots in Advice Letter 6259-E.

Three VGI pilots were subsequently authorized by CPUC Res.E-5192 (May 2022): VGI Pilot 1 for Residential customers, VGI Pilot 2 for Commercial customers, and VGI Pilot 3 for microgrids. OP 5 from Res.E-5192 also directed PG&E to file a subsequent advice letter to

[52] D.20-12-029, p. 43.

propose dynamic rate structures for VGI Pilots 1 and 2.[53] In Res.E-5326 (July 2024), the CPUC approved the final RTP rate structures for this "Phase II" of the VGI pilots that included RTP rate structures.[54] In Phase II of the Residential VGI Pilot (VGI Pilot 1) and Phase II of the Commercial VGI Pilot (VGI Pilot 2), participants are required to enroll in an RTP rate with day-ahead hourly MEC and MGCC components, as well as a distribution cost component. The RTP design for Phase II of the VGI Pilots includes a subscription based on a pre-defined customer-specific load profile.[55] To distinguish the rate structure proposed for the Phase II VGI Pilots (generation + distribution signal with a scaled subscription) from the rate structure approved for the DAHRTP Stage 1 and DAHRTP BEV rates (generation signal with no subscription), we refer to the rate structure for the Phase II VGI Pilots as Hourly Flex Pricing (HFP).

The HFP structure, for Phase II of the VGI Pilots, better reflects the CEC's LMS recommendations as compared with the DAHRTP BEV Pilots, which would have only provided an hourly MEC and MGCC price signal (i.e., no distribution price signal). Under the HFP rate structure being used for Phase II of the VGI Pilots, PG&E provides the generation RTP rate component to bundled customers, while CCAs provide the generation RTP rate component to their unbundled customers. Under this structure, PG&E also provides a day-ahead hourly distribution price signal to both bundled and unbundled customers designed to recover the Primary Distribution Capacity Costs approved in D.21-11-016. The hourly distribution prices vary depending on the forecasted load on a representative circuit with load characteristics that are similar to the customer's circuit. PG&E's Residential Phase II VGI Pilot 1 and Phase II Commercial VGI Pilot 2 were launched in October 2024. As of October 1, 2025, there are 144 BEV sites (service agreements) and two distinct customers with 160 MW enrolled in Phase II of the VGI Pilots, with a single bidirectional customer with Rule 21 Interconnection in place and eligible for exporting to the grid. PG&E is still

53 Res.E-5192, p. 34, OP 5.

54 Res.E-5326, pp. 9-12.

55 PG&E AL 6694-E, pp. 2-13.

working with CPUC staff on the evaluation strategy for Phase II of the VGI pilots.[56]

As Phase II of the VGI Pilots has progressed, PG&E has gleaned some learnings that have shaped our RTP proposal here, as presented in Chapter 2. A key piece of feedback was that the rate structure was too complex, especially the scaled subscription which made optimizing load management to generate bill savings challenging.

Another learning so far has been that circuit-level distribution pricing is very challenging to manage from both an implementation and customer understanding perspective, due to the dynamic nature of the distribution system in which service points are switched to a different circuit as part of standard distribution operations procedure to manage load. By design, the HFP distribution price component is tied to the monthly forecasted load shape of the representative circuit used to determine the RTP distribution pricing. One customer participating in Phase II of the VGI Pilots experienced a significant change in pricing when additional load associated three large industrial customers was added to the customer's representative circuit which caused the forecasted circuit load to exceed the historical maximum on the customer's representative circuit and led to high prices at all hours. Then, after a few months, that additional load was removed from the representative circuit, which significantly lowered prices and removed arbitrage opportunity for the participating customer, leading to customer dissatisfaction. PG&E is still evaluating the appropriate approach to establishing an RTP distribution price signal and further learnings from the pilots will help inform that approach.

7. SDG&E's EV Charging Station RTP Pilot and Export Rate Pilot – 2017-Present

SDG&E has optional dynamic pilot rates for customers who receive an SDG&E-owned and operated Electric VGI charging station through its Power Your Drive program, which has deployed hundreds of sites

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[56] Res.E-5192 requires CPUC ED staff concurrence on the VGI evaluation scope and final report deadline.

with thousands of charging ports throughout SDG&E's service area.[57] SDG&E's "Schedule VGI" and "Schedule Public Grid Integrated Rate (GIR)" rate offerings provide day-ahead hourly price signals that include marginal energy and capacity cost components, as well as circuit-level distribution pricing signals.[58] These rates are different from the hourly pricing rates piloted by VCE, SCE, and PG&E, as the rate is composed of not only a "day-ahead" rate based on forecasted grid conditions, but also a Critical Peak Pricing adder for both generation and distribution. The generation adder is designed to reflect the system's top 150 system peak hours and the distribution adder is designed to reflect the top 200 annual hours of peak demand for the individual circuit feeding the VGI charging stations. Those adders, which are only applied on event days, are substantially higher than the other price components.[59]

a. Evaluation of Schedule VGI

In April 2025, an evaluation report of sites taking service under SDG&E's Schedule VGI was published.[60] The analysis leveraged 223 sites with port data available. Three main types of sites were analyzed: 1) workplace charging sites where electric vehicle drivers were exposed to the dynamic prices 2) charging sites at multi-family dwellings where drivers were also charged at the dynamic prices 3) charging sites where the site hosts were exposed to dynamic prices but not the drivers using the charging facilities. The evaluation found statistically significant load response for the workplace and multifamily dwelling sites at which drivers were exposed to the dynamic prices of Schedule VGI. Estimated load elasticities were in the range of -0.25 to -0.35, which indicates that

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57 Energetics on behalf of SDG&E, Power Your Drive Research Report (Apr. 2021).

58 Schedule VGI was adopted by D.16-01-045 and implemented in 2017. Schedule Public GIR was adopted by D.18-01-024 and implemented in 2019.

59 SDG&E Schedule VGI and SDG&E Schedule Public GIR, available at: <https://tariffsprd.sdge.com/sdge/tariffs/?utilId=SDGE&bookId=ELEC&sectId=ELEC-SCHEDS&tarfRateGroup=Miscellaneous> (accessed Oct. 18, 2025).

60 Demand Side Analytics, 2024 Load Impact Evaluation of San Diego Gas and Electric's Vehicle Grid Integration Rate (Apr. 2, 2025) (2024 SDG&E VGI Load Impact Evaluation), available at: <https://www.calmac.org/publications/DSA_PY2024_Vehicle_Grid_Integration_Report_Public_FINAL.pdf> (accessed Oct. 18, 2025).

a 10 percent increase in price was associated with a 2.5-3.5 percent reduction in usage.[61]

b. SDG&E's Challenges with Circuit-Specific Pricing

A component of SDG&E's schedules VGI and Public GRI includes a circuit-specific distribution price adder. SDG&E has reported challenges with implementing circuit-level-specific rates for the following reasons:

1) It was challenging to assign customers to a specific circuit given that customers were often moved between circuits as part of standard distribution grid operations to manage load (load switching).
2) Customers on more constrained circuits were subject to higher prices as more events with high distribution pricing were called for those customers. This raised fairness considerations because customers are unable to control which circuit serves their load.[62]

c. Additional Regulatory Background on Hourly Pricing for SDG&E

In December 2021, SDG&E proposed two RTP Pilots for approval by the CPUC per directives from D.20-12-023 and D.21-07-010 (OP 6) that would apply to a broader set of customers than the EV charging specific Schedule VGI and Schedule Public GIR. In A.21-12-006, SDG&E proposed an optional import-only RTP pilot for large Residential, Commercial, and Agricultural classes that would be based on hourly day-ahead CAISO pricing. That same month, SDG&E submitted A.21-12-008 to propose an optional RTP rate for exports of energy to the grid. This export rate would be available to customers taking service on SDG&E's Electric Vehicle High Power Rate. The RTP export pilot rate would provide credits to customers that export energy to SDG&E based on CAISO prices and generation capacity costs.

The Commission combined applications A.21-12-006 and A.21-12-008 into one proceeding and then adopted D.23-11-006 that approved the dynamic pricing export pilot (SDG&E Export Rate Pilot) but dismissed the proposed RTP import pilot. The SDG&E Export Rate Pilot for SDG&E's Small Commercial and Medium/Large C&I customers,

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61 2024 SDG&E VGI Load Impact Evaluation, pp. 4-5.

62 R.22-07-005, CPUC, DFOIR, Track B Working Group Report (Oct. 11, 2023), p. 78.

which includes a dynamic generation price signal but not a dynamic distribution price signal,[63] was implemented in January 2025. The Commission dismissed the dynamic pricing import pilot because it realized that the then-upcoming decision in the DFOIR Track B proceeding (R.22-07-005) would provide additional guidance on RTP rate design.[64] The DFOIR Track B Final Decision has directed SDG&E to submit an RTP proposal for deployment across customers sectors.[65]

8. CPUC DER Action Plan 2.0 – 2022

In December 2021, the CPUC released a draft DER Action Plan 2.0 which was finalized in April 2022. The Action Plan included a "Vision Element" to enable access to RTP for all customer classes by 2025 to facilitate decarbonization and affordability objectives.[66]

9. CEC's LMS – 2021 to Present

In December 2021, the CEC staff proposed amendments to the CEC's LMS in Docket 21-OIR-03, with the goal of establishing a statewide system of granular time- and location-dependent signals that would be communicated to automation-enabled electric end uses through a CEC platform, the Market-Informed Demand Automation Service (MIDAS), to provide real-time load flexibility. The purpose of this load flexibility would be to enable more effective utilization of electric system assets, particularly as beneficial electrification of transportation and other end uses increases demand on the electric grid.[67] After considering public comments on the CEC's proposed amendments, the CEC adopted its final LMS amendments

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63 D.23-11-006, pp. 13 and 18; p. 34, OP 2.

64 D.23-11-006, p. 10.

65 D.25-08-049, p. 146, OP 1. SDG&E requested an extension of the CPUC's deadline, and was granted leave to file by February 1, 2026.

66 CPUC, DER Action Plan 2.0 (Apr. 21, 2022), p. 8.

67 As outlined in the CEC's Load Management Rulemaking Final Staff Report, Analysis of Potential Amendments to the Load Management Standards (Nov. 2021), available at: <https://www.energy.ca.gov/publications/2021/analysis-potential-amendments-load-management-standards> (accessed Oct. 19, 2025).

in October 2022, which went into effect in April 2023.[68] The CEC's LMS amendments required the large IOUs, CCAs, and Publicly-Owned Utilities to provide optional hourly "Marginal Cost-Based Rate" proposals for all customer classes, which, in the case of the IOUs, will require adoption by the CPUC before becoming effective.[69] Under the CEC's amended LMS requirements, compliant LMS marginal cost-based hourly rates would need to be proposed to each utility's respective rate-approving body by January 1, 2025[70] with a goal of making any such approved new rate available to customers on an opt-in basis across all customer classes by January 1, 2027. However, this was contingent on approval of the rates and cost recovery by each utility's respective rate approving body—which, in the case of PG&E, SCE and SDG&E—requires CPUC approvals that have not yet been issued.[71]

The amended LMS required that proposed RTP Rates should include a marginal cost-based component not only reflecting hourly or sub-hourly generation energy and capacity costs, but also new RTP rate components that reflect hourly or sub-hourly distribution and transmission costs.[72]

As part of PG&E's Supplemental RTP Testimony in our ongoing 2023 GRC II application (A.24-09-014), PG&E herein proposes methods for providing hourly generation energy and capacity prices (See Chapter 2,

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68 The LMS regulations are contained in the California Code of Regulations (CCR), Title 20, §§ 1621-1625, and carry out the CEC's statutory mandate to establish utility programs that reduce peak electricity demand, help balance electricity supply and demand to support grid reliability and provide clean and affordable electricity services to Californians. The CEC proposed these amendments to the LMS to expand utility incentive programs to be better able to shift loads to periods of high renewable generation, in support of a carbon-free grid as envisioned by SB 100 (De León, 2018). (Initial Statement of Reasons, CEC Docket No. 21-OIR-03, Notice Published on Dec. 24, 2021.)

69 20 CCR, § 1623(a)(1). Streetlighting customers are not included.

70 20 CCR, § 1623(a)(2). See also: CPUC staff submission, LMS Docket 23-LMS-01 (June 8, 2023), *Load Management Standards Compliance Timeline.* Large CCAs and POUs are subject to a comparable requirement but have different time deadlines than the IOUs. The deadline for Large POUs to apply to their rate-approving bodies for approval of at least one marginal cost-based rate was April 1, 2025 and for Large CCAs was July 1, 2025.

71 20 CCR, § 1623(d)(2).

72 20 CCR, § 1623(a)(1).

Sections D-G of this testimony) and distribution prices (Chapter 2, Section H). PG&E does not propose hourly transmission prices here. PG&E plans to propose dynamic transmission prices to FERC in 2026 as FERC has exclusive transmission rate jurisdiction and thus must first approve transmission rates. PG&E is in the process of conducting studies and obtaining stakeholder feedback on the appropriate framework for establishing dynamic transmission price signals. Furthermore, as requested by the DFOIR Track B Decision, PG&E has conferred with SCE and SDG&E on our respective approaches to developing a dynamic transmission price signal.[73]

Per LMS requirements, PG&E submitted a Compliance Plan in October 2023, which was subsequently revised through March 2025[74] and approved by the CEC on May 8, 2025.[75] A subsequent annual compliance plan to the CEC is due on May 8, 2026 and PG&E will update our plan to reflect developments related to PG&E's next steps with RTP Rates per PG&E's A.24-09-014 and guidance over the next year on dynamic rates established through the EDROIR discussed in Section D.12 of this chapter.

10. CPUC Energy Division's CalFUSE Policy Framework – 2022

In June 2022, the CPUC Energy Division released a white paper and staff proposal titled "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation." In this paper, CPUC staff envisioned a California Flexible Unified Signal for Energy (CalFUSE) Policy Framework that it believed could support provision of RTP price signals to customers, with the objective of incentivizing load response. In that white

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73 D.25-08-049, p. 67.

74 PG&E's Second Revised Load Management Standards Compliance Plan, current as of January 1, 2025, with minor grammatical revisions added on February 24, 2025, (CEC submission Mar. 18, 2025), available at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-lms-01> (accessed Oct. 19, 2025).

75 Signed Orders Approving LMS Compliance Plans for PG&E, SCE, SDG&E, VCE, SJCE, and PCE from the May 8, 2025 Business Meeting (CEC submission May 16, 2025), available at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-lms-01> (accessed Oct. 19, 2025).

paper—which is referred to here as the "CalFUSE White Paper"— CPUC staff suggested the following policy vision:

> *To achieve widespread customer adoption of low cost, advanced flexible demand and DER management and compensation solutions across the state (and beyond) via a unified, universally accessible, dynamic economic signal.*[76]

The Commission referred to the CalFUSE White Paper in the DFOIR (R.22-07-005), where the Commission established Track B, to provide guidance to jurisdictional IOUs for future dynamic pricing rate design.[77] The CalFUSE White Paper was considered as part of the DFOIR Track B proceeding, as discussed in the next section.

11. DFOIR Track B

Building on the CalFUSE policy framework introduced in the CalFUSE White Paper and noting the CEC's LMS, on July 14, 2022, the CPUC launched R.22-07-005, the Demand Flexibility Order Instituting Rulemaking (DFOIR). This Rulemaking sought "to establish demand flexibility policies and modify electric rates to advance the following objectives:

a) [E]nhance the reliability of California's electric system;
b) [M]ake electric bills more affordable and equitable;
c) [R]educe the curtailment of renewable energy and [GHG] emissions associated with meeting the state's future system load;
d) [E]nable widespread electrification of buildings and transportation to meet the state's climate goals;
e) [R]educe long-term system costs through more efficient pricing of electricity; and
f) [E]nable participation in demand flexibility by both bundled and unbundled customers."[78]

The Rulemaking consisted of two tracks, A and B. Track A was focused on compliance with California Assembly Bill 205, which required the

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76 CPUC, Energy Division, Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022) (CalFUSE White Paper), p. 2.

77 R.22-07-005, Assigned Commissioner's Phase 1 Scoping Memo and Ruling (Nov 2, 2022), p.11. .

78 R.22-07-005, OIR to Advance Demand Flexibility through Electric Rates (Jul 22, 2022), p. 1.

authorization and implementation of a fixed charge for residential customers of California's IOUs. The objective of Track B of the DFOIR was to expedite the adoption of demand flexibility rates such as RTP for large electric IOUs.[79] The DFOIR was closed in August 2025 through the DFOIR Track B Final Decision.[80]

a. Rate Design and Demand Flexibility Principles

As part of the DFOIR Rulemaking, Track B, the CPUC established revised rate design principles and new demand flexibility principles in D.23-04-040 to guide assessment of future rate proposals by PG&E, SCE, and SDG&E. PG&E has considered these principles in developing our Supplemental RTP rate proposal, described in Chapter 2.

1) CPUC Revised Rate Design Principles

The Rate Design Principles represented revisions from the CPUC 2014 Rate Design Principles adopted in D.14-06-029. The revised Rate Design Principles[81] are the following:

1) All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost;
2) Rates should be based on marginal cost;
3) Rates should be based on cost causation;
4) Rates should encourage economically efficient: (1) use of energy, (2) reduction of GHG gas emissions, and (3) electrification;
5) Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner;
6) Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs;

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79 R.22-07-005, Assigned Commissioner's Phase 1 Scoping Memo and Ruling (Nov. 2, 2022), p. 2.

80 D.25-08-049, p. 148, OP 8.

81 D.23-04-040, pp. 36-37, OP 1.

7) Customers should be able to understand their rates and rate incentives and should have options to manage their bills;
8) Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals;
9) Rate design should not be technology-specific and should avoid creating unintended cost-shifts; and
10) Transitions to new rate structures should: (1) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (2) minimize or appropriately consider the bill impacts associated with such transitions.

2) CPUC Demand Flexibility Principles

The CPUC adopted Demand Flexibility Principles in 2023,[82] to guide the development of demand flexibility tariffs, systems, processes, and customer experiences. These adopted principles were :

1) Demand flexibility tariffs should be designed in accordance with all of the Commission's Electric Rate Design Principles;
2) Demand flexibility tariffs should provide a dynamic price signal in a standardized format that can be integrated into third-party DER and demand management solutions;
3) Dynamic prices should, to the extent feasible, accurately incorporate the marginal costs of energy, generation capacity, distribution capacity, and transmission capacity based on grid conditions;
4) The systems and processes for calculating dynamic price signals should be able to include bundled and unbundled rate components so that any LSE can elect to participate;
5) Customers (including low-income customers and those who receive a medical baseline or discount) should have access to tools and mechanisms that enable them to plan and schedule their energy use while managing the monthly variability of their bills; and
6) Demand flexibility tariffs should provide marginal cost-based compensation for exports to enable economically efficient grid integration of customer-sited electrification technologies and DERs.

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[82] D.23-04-040, p. 37, OP 2.

b. Track B Working Group and Report

As part of the DFOIR, the CPUC convened Working Group 1, which met every two weeks from January through August 2023 to consider RTP rate design, including how such rates should be designed to comply with the CEC's LMS. In accordance with the DFOIR Scoping Memo, the Joint IOUs submitted a report in October 2023 summarizing the Joint IOUs' proposal for RTP rate design, informed by the Track B Working Group discussions.[83] PG&E's RTP proposal here reflects some features of the RTP design proposals articulated in the Joint IOU Track B Working Group report, while incorporating refinements based on further considerations and learnings since October 2023 as well by the guidance provided in the DFOIR Track B Decision.

c. DFOIR Track B Expanded Pilots

In August 2023, the ALJ issued a Ruling in the DFOIR Track B Decision to consider the expansion of the pilots that were approved as part of the Summer Reliability proceeding in 2022; the VCE AgFIT and SCE Dynamic Pricing Pilots discussed in Section D.4 of this Chapter. After considering stakeholder feedback and proposals from PG&E, SCE, intervenors, and VCE, the CPUC issued a Final Decision on these Pilots in DFOIR Track B. This Decision (D.24-01-032) authorized expanded RTP rate pilots in PG&E and SCE's service areas.[84]

In D.24-01-032, the Commission directed PG&E to continue and build upon the VCE AgFIT Pilot and create two new pilots. The first pilot expands eligibility for RTP Rates to Agricultural customers on eligible rates throughout PG&E's service territory (HFP Pilot 1). The second pilot (HFP Pilot 2) expands eligibility for RTP to customers in PG&E's service territory on Large Commercial B19, B20 rates, Small and Medium Commercial B6 and B10 rates, as well as Residential electrification rates (EV2A and E-ELEC).[85]

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83 R.22-07-005, CPUC, DFOIR, Track B Working Group Report (Oct.11, 2023).

84 D.24-01-032, p. 83, OP 1. SCE's Expanded Pilot is also known as "The [SCE] Flexible Pricing Rate Pilot."

85 D.24-01-032, p. 21.

Please note that PG&E renamed these “Expanded” pilots the “Hourly Flex Pricing (HFP) Pilots” and we will refer to them as such in this Testimony. The pilots were authorized to extend until the end of 2027 and are to be available to CCA customers whose CCA elects to participate by providing a generation RTP rate component.

In AL E-7222,[86] PG&E proposed an implementation plan for the HFP Pilot for all Agricultural customers in PG&E’s service area (HFP Pilot 1) and for the pilot that would make RTP Rates available to customers currently taking service on certain Commercial/Industrial rates and Residential electrification rates (HFP Pilot 2). These pilots contain elements required to comply with the CEC LMS (MEC and MGCC components and an RTP distribution component), as well as additional elements that were outlined as part of the CalFUSE framework (e.g., subscription).[87] PG&E’s HFP Pilots began enrolling customers in November 2024.

As of October 1, 2025, PG&E has over 1,900 service agreements enrolled in the HFP Pilots, representing over 340 MWs of demand. PG&E has developed learnings from these pilots that informed the rate design proposed in Chapter 2.

Key learnings so far have been the following:

- *CCA Engagement:* Engaging CCAs adds significant coordination costs but is critical given that avoiding generation costs is a key potential value stream from RTP Rates and because a large portion of PG&E’s load is served by CCAs.
- *Subscriptions:* Some customers find subscriptions challenging to negotiate to achieve bill savings. Specific initial findings related to subscriptions included the following:
  - Customers with significant year-to-year variation in usage (e.g., Agricultural and some Commercial and Industrial customers) can experience challenges with subscriptions that are based on historical usage. A subscription that is too high can subject

86 AL 7222-E, PG&E Implementation Plans for PG&E’s Agricultural Pilot and Expanded Pilot 2 (submitted Mar. 25, 2024).

87 AL 7222-E, p. 14.

customers to inappropriately high charges (especially Demand charges) and a subscription that is too low can create structural winners (customers who achieve bill savings without changing load patterns) if load factors have also changed.

- The approach of scaling the subscription at the end of the month based on actual usage to address year-to-year load variability muddles the price signal customers face when changing usage in a given hour. For example, if a customer wanted to significantly increase usage during low RTP cost hours (without reducing usage elsewhere), they must first buy their historical usage profile at OAT prices. However, that profile is then scaled to reflect the higher total usage using a scaling factor that is not established until the end of the billing cycle (based on total monthly usage). This would mean that the customer would have to buy additional load at the OAT price during those low RTP cost hours, without certainty of what portion of their usage will be charged at the higher OAT vs. the lower RTP price

- *Shadow Billing:* Similar to the findings from the VCE AgFit Pilot and SCE Dynamic Rate Evaluation reports, PG&E is finding that shadow billing may make it challenging to clearly attribute load response to the RTP rate because customers have an incentive to pay attention to two sets of price signals at once (OAT rates and the hourly prices). A customer's response to the dynamic rate could result in an increase to their OAT bill, and customers have been found to be more mindful of managing their OAT bill rather than pursuing a credit for responding to the HFP price.

d. DFOIR Track B Final RTP Guidance Decision

The most notable regulatory development that has occurred since PG&E submitted our original RTP proposal in PG&E's 2023 GRC Ph II Testimony from September 2024, is the issuance of the DFOIR Track B Decision as part of the Demand Flexibility OIR Track B to which this

Supplemental RTP Testimony is responsive.[88] This Decision provided guidance for the Large Investor-Owned Utilities' (Large IOU), including PG&E, SCE, and SDG&E's Real-Time Pricing rate designs, which we will review at a high level here.

1) Marginal Costs

The DFOIR Track B Decision provides additional guidance on how PG&E's rate proposal should incorporate marginal costs, including Marginal Energy Costs (MEC), Marginal Generation Capacity Cost (MGCC), Marginal Distribution Capacity Cost (MDCC), Marginal Transmission Capacity Costs (MTCC), and Marginal Customer Access Costs. The DFOIR Track B's guidance for including each of these cost areas for RTP rate design is summarized in Table 1-3.

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88 On September 29, 2025, SDG&E filed an Application for Rehearing of D.25-08-049 (AFR) on the grounds that it is based on an insufficient record and insufficient procedural process, and fails to take into consideration any costs associated with the prescribed rate design, On October 14, 2025, PG&E filed a response supporting the AFR's position that D.25-08-049 lacks necessary cost effectiveness evidence and findings to support its direction to the IOUs for RTP rates. The Small Business Utility Advocates (SBUA), and Center for Assisted Technologies (CforAT) also each filed responses supporting SDG&E's request for rehearing. The Commission's decision granting any of the AFR's requests could result in modification to the guidance in the DFOIR Track B Decision.

TABLE 1-3
CPUC'S MARGINAL COST GUIDANCE IN D.25-08-049

Line No.	Cost Category	Guidance	Reference in the DFOIR Track B Decision (D.25-08-049)
1	MEC	Use CAISO's day-ahead energy market price at Default Load Aggregation Points as the MEC in DF Rate Proposals	p. 23, Conclusion of Law (COL) 2
2	MEC Line Losses	Use a price function that is a function of the IOU's load forecast (such as a quadratic or similar price function) instead of applying a uniform scaling price component in their DF Rate Proposals to recover the cost of electricity that is lost due to delivery through T&D lines.	p. 28-30, COL 3, COL 4
3	MGCC	Include an MGCC price component based on long-run marginal costs that are scaled to recover all long-run marginal generation capacity costs, include a peak MGCC price component that is a function of system net load, and a flex MGCC price component to provide a daily load shift price signal that supports system ramping needs and reduces renewable curtailment. MGCC values from the most recent GRC Phase 2 applications and the Avoided Cost Calculator (ACC) MGCC values should be submitted.	pp. 40 and 48, COL 5, COL 12, COL 13
4	MDCC	Must include an hourly MDCC component that is location-based (at a substation or circuit cluster level) and appropriately recovers the costs that vary with customer class and voltage level. Proposed non-coincident demand charges should recover specific non-peak distribution costs that are clearly shown to be caused by individual customer non-coincident demand rather than system or circuit peak loads	pp. 60-61, COL 14
5	MTCC	Large IOUs are directed to describe their plan to design MTCC price components that will be incorporated in DF Rate Proposal	p. 67, COL 16, COL 17

The DFOIR Track B Decision also provides guidance on how these marginal costs should be updated and gives the IOUs the opportunity to update MGCC and MDCC on an annual basis.[89]

2) Non-Marginal Costs

To collect costs that are not marginal (i.e., do not vary with the amount of energy used), the Decision directs the Large IOUs to use an Equal Percent Marginal Cost (EPMC) scalar applied to time-varying marginal prices, or use a time-differentiated Revenue Neutral Adder (RNA). IOUs that select a time-differentiated RNA must provide testimony, workpapers, and analysis in their proposals that provide a side-by-side comparison for using RNA in lieu of an EPMC scalar. Furthermore, IOUs are required in their RTP proposals to provide a detailed description of the elements and cost drivers comprising their proposed non-marginal generation costs. IOUs are also required to describe their approaches to recovering "revenue categories that are not already addressed through the scaling of time-varying rate components (e.g., marginal customer access costs, non-peak marginal distribution capacity costs, other non-marginal costs) through alternate rate design elements…." Finally, the IOUs are directed to show how recovering "costs through non-volumetric rate elements (e.g., fixed charges, non-coincident demand charges, customer load-shape subscriptions) … might affect a customer's incentive to shift load to low-cost and/or low-emission hours."[90]

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[89] D.25-08-049, pp. 86-88. On September 29, 2025, SDG&E filed an Application for Rehearing of D.25-08-049 (AFR) on the grounds that it is based on an insufficient record and insufficient procedural process, and fails to take into consideration any costs associated with the prescribed rate design, On October 14, 2025, PG&E filed a response supporting the AFR's position that D.25-08-049 lacks necessary cost effectiveness evidence and findings to support its direction to the IOUs for RTP rates. The Small Business Utility Advocates (SBUA), and Center for Assisted Technologies (CforAT) also each filed responses supporting SDG&E's request for rehearing. The Commission's decision granting any of the AFR's requests could result in modification to the guidance in the DFOIR Track B Decision.

[90] D.25-08-049 pp. 79-80 and COL 21.

3) Export Rates and Export Compensation

The Commission did not direct IOUs to provide export compensation as part of their RTP rate proposals, but provided guidance that, should an IOU elect to provide export compensation, that compensation should be asymmetric to the RTP price and should only reflect marginal costs. The CPUC notes that exports to the grid do not offset the non-marginal costs (such as wildfire mitigation and vegetation management, reliability improvements, safety and risk management of the distribution system, ongoing distribution operations and maintenance, among others) that are collecting through the non-marginal cost portion of the HFP price.[91]

4) Subscriptions and other Customer Protections

The CalFUSE framework included "two-part" rates on which a customer taking service on a dynamic rate would be billed. Such a rate is designed to limit customer exposure to very high RTP prices and improve revenue recovery assurance for the load serving entity. In this billing structure, what a customer owes in a given month is a function of two parts: One part would be charges using a pre-determined "subscription" level of usage (generally tied to a customer's previous twelve months of usage) and the Otherwise Applicable Tariff (OAT) on which a customer would be billed, i.e., the rate that would apply to them if they were not taking service on an RTP rate. The other part of a customer's bill would be a function of their actual usage and the hourly RTP price. Under this structure, usage below the subscription amount is credited at the RTP price, and only incremental usage above the subscription amount is charged at the RTP price. This is illustrated in Figure 2-21 in Chapter 2 of this Testimony. The credits and charges are decremented or added to the amount the customer would owe—calculated based on the subscription level of usage and the customers' OAT—to determine what the customer should be charged. The DFOIR Track B Final Decision does not require the

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[91] D.25-08-049, pp. 95-96, COL 24.

IOUs to offer two-part rates with subscriptions as part of their RTP rate proposal, but does leave the option available. The Decision allows the IOUs to maintain flexibility in how to address customer protections and identifies subscriptions, price adjustment, bill limiters and bill protection, as well as transactive prices as potential viable approaches.[92]

5) Transactive Pricing

Transactive Pricing in an RTP context involves the LSE developing an hourly price forecast and offering that forward pricing to a customer through a forward transaction. This can enable customers who are able to schedule loads in advance (such as water pumping load) to plan usage at times of locked-in low prices. The DFOIR Track B final decision found that it is reasonable for the Large IOUs to include Transactive Pricing in their RTP rate proposals but that forward transactions should be offered no earlier than a week ahead.[93]

12. Enhanced DR OIR and Implementation of RTP Rates

In September 2025, the CPUC issued R.25-09-004 to open a Rulemaking that "seeks to evaluate and enhance the consistency, predictability, reliability, and cost-effectiveness of demand response resources."[94] The proposed scope of this proceeding includes an update to the CPUC's Demand Response guiding principles, policies, and data system and process requirements.[95] The EDROIR preliminary scoping memo also discusses potential scope related to RTP rates as well as certain CEC LMS requirements that had originally been part of the Demand Flexibility Track B rulemaking, but were removed from scope by the DFOIR Track B Final Decision.[96] The DFOIR Track B Decision noted that issues relating to

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92 D.25-08-049, p. 144, COL 29.

93 D.25-08-049, pp. 117-118, COL 27.

94 R.25-09-004, Order Instituting Rulemaking to Enhance Demand Response in California (Sept. 18, 2025) (EDROIR), p. 1.

95 EDROIR, p. 9.

96 D.25-08-049, p. 13.

systems and processes to enable access to RTP Rates (referred to as Demand Flexibility Rates in the Decision) and implement the CEC's LMS would be addressed in one or more new rulemakings. The preliminary EDROIR scoping memo states that the EDROIR "will address the implementation of dynamic rates by developing the appropriate systems and processes but will not address the rate design aspects of the dynamic rates being used by these systems and processes."[97]

The full scope for the EDROIR is still being developed, but PG&E expects that this rulemaking will provide important guidance that will help guide PG&E's implementation plans for RTP (referred to as dynamic rates in the EDROIR) in terms of what systems and processes should be made available to support RTP. While the EDROIR scope is still being developed, the DFOIR Track B Decision provides some guidance as to what may be in scope of the EDROIR rulemaking related to the implementation of dynamic rates that was removed from the DFOIR Track B rulemaking. In the DFOIR Track B Decision, it states that "the Track B, Working Group 2 Issues 4, 5, and 6 that relate to systems and process to enable access to dynamic rates" as well as "Commission support on implementing amendments to the CEC LMS" will be addressed in a new rulemaking.[98] Issues 4,5, and 6 in the DFOIR Track B Final Decision were the following:

4. How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?
    a. What systems and processes should the Commission authorize for computation of dynamic prices for bundled and unbundled customers?
    b. What systems and processes should the Commission authorize to enable load serving entities to offer unbundled customers the option to take service on dynamic electricity prices?

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97 EDROIR, p. 8.

98 D.25-08-049, p. 13.

c. What systems and processes should the Commission authorize to enable third-party service providers (e.g., automation service providers, device manufacturers) to offer demand flexibility services to customers?

d. What systems and processes should the Commission authorize to enable customers to optimize and pre-schedule their energy use to provide demand flexibility (e.g., forward transactions)?

e. What are the costs associated with these systems and processes (for access to prices and responding to price signals), and how should these costs be recovered?

f. How should these systems and processes (for access to prices and responding to price signals) be managed and overseen (e.g., utility administration or third-party administration)?

5. How should the Commission support the implementation of the amendments to the California Energy Commission's Load Management Standards?

6. Should the Commission expand any of the existing dynamic rate pilots as a near-term solution that will benefit system reliability?[99]

PG&E plans to provide feedback on the appropriate scope of the EDROIR as it relates to dynamic rates and the CEC's LMS in our comments on the Rulemaking that will be submitted on November 13, 2025.

13. Summary of Learnings Thus Far from RTP Pilots

In the preceding sections of this chapter, we have discussed learnings from the RTP Pilot rates that have been deployed in PG&E's, SDG&E's, and SCE's service areas, as well as the VCE AgFit pilot run by the VCE. Here, we summarize key high-level learnings from those pilots that have informed the RTP rate design outlined in Chapter 2. Chapter 2 further discusses how pilot learnings to date have informed PG&E's revised RTP rate design proposal.

Please keep in mind that while the VCE AgFit Pilots, SCE's Dynamic Rate Pilot, and SDG&E Schedule VGI pilots have undergone formal

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99 Assigned Commissioner's Phase 1 Scoping Memo and Ruling (Nov. 22, 2022), R.22-07-005, pp. 5-6.

evaluations, PG&E will not have a formal public evaluation until the HFP midterm Evaluation Report planned for August 2026. Nonetheless, in sections 6 and 11.d of this Chapter, PG&E has shared some initial findings based on our experience, to date, with the Phase II VGI and HFP pilots.

Key learnings from the RTP pilots reviewed in this chapter include the following:

- *CCA Engagement:* It is important to devote appropriate resources to engaging CCAs, given that avoiding generation costs is a key potential value stream from RTP Rates and approximately half of PG&E's load is served by CCAs.[100]
- *Subscriptions*: Some customers find subscriptions challenging to negotiate to ensure they are optimizing bill savings. Customers with significant year-to-year variation in usage may face challenges negotiating subscriptions that are tied to the prior year's historical usage.[101]
- *Shadow Billing:* Shadow billing makes it difficult to attribute load response to the RTP rate because customers have an incentive to pay attention to two sets of price signals at once (OAT rates and the hourly prices). Furthermore, this structure has potentially attracted customers who are testing whether or not they can be structural winners on RTP rate design (i.e., get credits without changing load patterns).[102]
- *Distribution Pricing:* Circuit-level distribution rate design must be robust to the dynamic nature of the distribution system in which service points are switched to a different circuit as part of standard distribution operations to manage load. This can cause the distribution pricing (which is a function of circuit load) to change quickly and drastically, leading to significant changes in the opportunity for load management to

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[100] CPUC, Community Choice Aggregation and Energy Service Provider Formation Status Report (Feb. 28, 2024), Figure 2, p.7, available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/2024-status-report-on-community-choice-aggregation-formation.pdf> (accessed Oct. 3, 2025).

[101] Based on PG&E's initial HFP Pilot experience and Final Evaluation of VCE's Pilot, p. 3.

[102] Based on PG&E's experience with the HFP Pilots and a) the Final Evaluation of VCE's Pilot , pp. 3, 82; b) Final Evaluation of VCE's Pilot, pp. 70-73.

generate bill savings for customers. Proper systems and resources are required to monitor and maintain accurate prices and attribution of load response.[103]

[103] PG&E's experience with Phase II of the VGI Pilots and R.22-07-005, CPUC, DFOIR, Track B Working Group Report (Oct. 11, 2023), p. 78. May be accessed at link in footnote 12, ante.

(PG&E-5)

TABLE 1-4
SUMMARY OF RTP PILOTS UNDER DEVELOPMENT OR UNDERWAY IN CALIFORNIA

Line No.	LSE/UDC	RTP Rate/Pilot/Application	Decision	Eligible Customers	RTP Components Included[(a)]	Status
1	VCE	AgFIT Pilot	D.21-12-015	Ag	GI, D, S, TFP	Final Evaluation Report issued April 2025.
2	SCE	Dynamic Rate Pilot	D.21-12-015	Residential and Commercial	GI, D, S, TFP[(b)]	Final Evaluation issued February 2025
3		Flexible Pricing Rate Pilot	D.24-01-032	Residential and Commercial	GI, D, S	Launched in July 2025
4	PG&E	DAHRTP-BEV Opt-In Rate	D.21-11-017	Commercial Electric Vehicle (CEV) Charging	GI	On hold as subsequently approved pilots provide better coherence with CEC LMS.
5		DAHRTP-BEV Non-NEM Export Pilot	D.22-10-024	CEV Charging	GE	
6		GRC 2 DAHRTP Stage 1 Pilots	D.22-08-002	Residential, Small and Medium Businesses (SMB), Large C&I	GI	
7		Phase II of VGI Pilots 1 and 2	D.20-12-029, and Res.E-5192,	Residential, SMB, Large C&I, CEV	GI, GE, D, S	Launched in October 2024
		Hourly Flex Pricing Pilots	D.24-01-032	All customer classes, except Streetlight	GI, GE, D, S, TFP for Pilot 1	Launched in November 2024
8	SDG&E	Schedules VGI and Public GIR	D.16-01-045, D.18-01-024	CEV Charging with SDG&E-Owned Charging Stations	GI, D	Active rate schedules
9		RTP Export Pilot	D.23-11-006	Small Commercial and Medium/Large C&I	GE	Implemented in January 2025

(a) LMS RTP requirements: Generation Import (GI) which includes marginal energy and capacity costs, Distribution (D), Transmission (T) CalFUSE additional components: Generation Export (GE), Subscription (S), Transactive Forward Price Contracts (TFP).
(b) As of May 1, 2024, this element was not available.

E. Dual Participation

PG&E's RTP rate Pilots were designed to understand how customers can respond to RTP signals, including measuring how customers shift or reduce load in response to high prices. The pilots authorized to date have differing approaches for allowing simultaneous customer participation in RTP and other load management programs, which is typically described as "dual participation." It is important to clearly measure load impacts of customers participating in RTP pilots without combining the effects of other load management programs, or "double counting" for short. It is also important to ensure the same load reduction is not compensated for more than once by different programs, which is described as "double compensation." To mitigate these issues, some RTP pilots limit dual participation to certain specified programs. For example, the DFOIR Track B HFP Pilots[104] and the Phase II VGI Pilots allow dual participation only with Critical Peak Pricing (CPP) programs (i.e., SmartRate™ and Peak-Day Pricing) and certain subgroups within the ELRP.[105] However, what programs and subgroups are allowed to dual participate are not consistent across all of the RTP pilots described in this chapter. On top of limiting participation within our own programs, PG&E is required to implement dual participation rules that prohibit RTP pilot customers from also participating in certain CCA programs.[106] Dual participation between RTP Rates and other load management and technology incentive programs is an increasingly complicated issue.

PG&E believes a holistic approach to dual participation is needed. Many of these issues are better suited for the EDROIR involving all utilities and other interested parties, rather than this proceeding for PG&E alone,[107] particularly given the benefits of a consistent approach across all IOUs and other LSEs. However, some elements of dual participation are fundamental to the success of RTP Rates and should be addressed in this case, particularly if the EDROIR does not address dual participation policy with RTP Rates. Those elements

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104 As approved in D.24-01-032.

105 D.24-01-032 authorizes additional programs to dual participate with the HFP Pilots; however, PG&E's implementation of dual participation treats them as part of the customer's OAT for the subscription calculation.

106 D.24-01-032, pp. 63-64: pp. 81-82, Conclusions of Law 34 and 36.

107 R.25-09-004.

include a need for consistency in treatment of dual participation across all RTP rate options, clarity regarding dual participation where PG&E has limited visibility to implement bill credits and incentive payments to prevent double compensation (such as with third-party providers), and the overall impact of dual participation restrictions on enrollment.

In its current state, the HFP Pilots authorized by D.24-01-032 allow dual participation with the following: CPP programs (such as Peak Day Pricing and SmartRate™), electrification rates (E-ELEC), time of use rates (including Schedules EV2A, B-6, B-10, B-19, B-20, AG-A1, AG-A2, AG-B, AG-C), NEM and NBT, and the ELRP Subgroups A1, A3, and A6.[108] PG&E's implementation treats TOU, E-ELEC, and NEM and NBT as part of the customer's OAT for the subscription calculation. For CPP programs, PG&E is addressing potential double compensation by adjusting the RTP bill credit for customers on a TOU and CPP rate with the following formula:

RTP Bill Credit = MAX (0,OAT TOU including CPP – shadow bill)

PG&E uses a similar calculation for dual participation between the HFP Pilots and ELRP Subgroups A1, A3, and A6:

RTP Bill Credit = MAX (0,OAT TOU including ELRP incentive – shadow bill)

However, PG&E does not have information about whether the customer is in a CCA or other non-PG&E event-based load-modifying program (such as the CEC Demand Side Grid Support) to address double compensation.

The Phase II VGI Pilots have similar dual participation prohibitions, with the exception that they *require* customers to dual participate with ELRP Subgroup A5.[109] In this case, PG&E is not able to implement the formula described above in the same manner as it can for ELRP Subgroups A1, A3, and A6. The reason for this is that PG&E does not calculate individual customer-level performance and incentives for all customers participating in ELRP, particularly

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[108] PG&E AL 7223-E-B, p. 6. Subgroup A1 is for non-residential, non-DR customers, including Base Interruptible Program (BIP) and non-BIP enrollees. Subgroup A3 is for Rule 21 exporting DERs. Subgroup A6 is for residential customers, participating under the Power Saver Rewards name. Subgroup A6 sunsets at the end of 2027.

[109] Res.E-5192, p. 23, Section 10.3. Subgroup A5 is for EV and VGI aggregators.

those who participate via aggregations, including Subgroup A5.[110] To address double compensation between its RTP Program and its ELRP Program, PG&E will request its Subgroup A5 aggregators to voluntarily provide the information to calculate a customer's actual ELRP compensation to prevent double compensation, or alternatively, will otherwise assume the customer receives the full ELRP incentive. This creates an inconsistency that may be appropriate for a first pilot phase but should not set a precedent for future RTP Rates.

This example with ELRP is generally applicable to all PG&E programs involving aggregators. PG&E is not privy to the customer payment information where it is not directly administering such incentives. Moreover, lack of visibility into customer payments, where payment is controlled by others, including CCAs, CEC, third-party providers, and aggregators when the information is needed to administer the Commission's principle against double compensation is a major obstacle. At the same time, protecting confidential information of entities operating programs that compete in the market is very important, especially where the CPUC does not have jurisdiction over those entities' programs. In all instances, there is a need for more universally applicable, comprehensive systems and processes to administer dual participation rules and address double compensation, while balancing the other legitimate state interests, including support for RTP and gathering data for analysis and a longer-term policy.

For the RTP proposal in this proceeding, PG&E recommends that the Commission not set precedents based on these pilots and allow flexibility for a more consistent and reasonable approach should one be determined through the course of the new EDROIR, or through our experience with the HFP Pilots and the Phase II VGI Pilots. On an interim basis, PG&E intends to keep the

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[110] In instances where customers are participating via aggregations in ELRP, and where the aggregator does not have PG&E calculate individual customer-level performance and incentives, PG&E has no visibility or information on arrangements between the aggregator and the aggregator's customers. The aggregator may have relationships with the customers defining incentive payments that differ from the compensation outlined in the ELRP program's terms and conditions, and such aggregators have no obligation to provide the details of these agreements with PG&E. Therefore, PG&E cannot accurately address double compensation with customers in ELRP subgroups that utilize aggregation, including subgroup A5—which is relevant to the VGI Pilots. This applies for bundled and unbundled customers alike.

existing dual participation prohibitions and double compensation formulas in place for the GRC II RTP Rates at this time, and propose revisions in PG&E's January 2026 Stop-Gap Interim RTP Pilot Proposal.

F. Organization of This Exhibit

Exhibit (PG&E-5) has a total of four chapters. The remainder of this exhibit is organized as follows:

- Chapter 2: Real Time Pricing and Load Management Standard Requirements;
- Chapter 3: Community Choice Aggregator Collaboration; and
- Chapter 4: Regulatory Roadmap for RTP Implementation and Cost Recovery

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT A

COMPLIANCE WITH DEMAND FLEXIBILITY RATE DESIGN PROPOSALS, ELECTRIC RATE DESIGN PRINCIPLES, AND DEMAND FLEXIBILITY RATE DESIGN PRINCIPLES

DATED OCTOBER 29, 2025

Compliance with Demand Flexibility Rate Design Proposals, Electric Rate Design Principles, and Demand Flexibility Rate Design Principles

In the table below, PG&E summarizes various compliance-related activities presented within Exhibit PG&E-5.

SUMMARY OF COMPLIANCE ITEMS IN EXHIBIT PG&E-5

Line No.	Requirement	Reference
1	**Cal. Code Regs., tit. 20, § 1623, Load Management Tariff Standard, effective April 1, 2023:** “(2) Within twenty-one (21) months of April 1, 2023, each Large IOU shall apply to its rate-approving body for approval of at least one marginal cost-based rate, in accordance with 1623(a)(1), for each customer class.”	Chapter 2
2	**Decision (D.) 23-04-040, Conclusion of Law (COL) 1:** “It is reasonable to adopt the Electric Rate Design Principles in Ordering Paragraph 1 for the assessment of all rates of the large IOUs.”	Chapter 2
3	**D.23-04-040, COL 2:** “It is reasonable to adopt the Demand Flexibility Design Principles in Ordering Paragraph 2 to guide the development of demand flexibility tariffs, systems, processes, and customer experiences of the large IOUs.”	Chapter 2
4	**D.23-04-040, COL 3:** “The Electric Rate Design Principles should be followed in the event of any perceived conflict between the Electric Rate Design Principles and the Demand Flexibility Design Principles.”	Chapter 2

Line No.	Requirement	Reference
5	**D.23-04-040, Ordering Paragraph (OP) 1:** "This decision adopts the following Electric Rate Design Principles for the assessment of all electric rates of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. a) All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost. b) Rates should be based on marginal cost. c) Rates should be based on cost causation. d) Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification. e) Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner. f) Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs. g) Customers should be able to understand their rates and rate incentives and should have options to manage their bills. h) Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals. (i) Rate design should not be technology-specific and should avoid creating unintended cost-shifts. (j) Transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.	Chapter 2

Line No.	Requirement	Reference
6	**D.23-04-040, OP 2:** "This decision adopts the following Demand Flexibility Design Principles to guide the development of demand flexibility tariffs, systems, processes, and customer experiences of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. a) Demand flexibility tariffs should be designed in accordance with all of the Commission's Electric Rate Design Principles. b) Demand flexibility tariffs should provide a dynamic price signal in a standardized format that can be integrated into third-party distributed energy resource and demand management solutions. c) Dynamic prices should, to the extent feasible, accurately incorporate the marginal costs of energy, generation capacity, distribution capacity, and transmission capacity based on grid conditions. d) The systems and processes for calculating dynamic price signals should be able to include bundled and unbundled rate components so that any load serving entity can elect to participate. e) Customers (including low-income customers and those who receive a medical baseline or discount) should have access to tools and mechanisms that enable them to plan and schedule their energy use while managing the monthly variability of their bills. f) Demand flexibility tariffs should provide marginal cost-based compensation for exports to enable economically efficient grid integration of customer-sited electrification technologies and distributed energy resources.	Chapter 2
7	**D.25-08-049, COL 1:** "It is reasonable to …(b) direct PG&E to serve supplemental testimony in A.24-09-014 to comply with the guidance for DF Rate Proposals in this decision within 60 days of the issuance of this decision…"	Exhibit PGE-5
8	**D.25-08-049, COL 2:** "It is reasonable to require the Large IOUs to use CAISO's day-ahead energy market price at DLAPs as the MEC in DF Rate Proposals to comply with the CEC LMS and effectively incentivize customer load shifting."	Chapter 2

Line No.	Requirement	Reference
9	**D.25-08-049, COL 3:** "It is reasonable to require the Large IOUs to include a line loss factor in the MEC in their DF Rate Proposals to recover the cost of replacement electricity."	Chapter 2
10	**D.25-08-049, COL 4:** "It is reasonable to require that each of the Large IOU's proposed methodologies to calculate line losses reflect the time or load-dependent nature of these losses."	Chapter 2
11	**D.25-08-049, COL 5:** "It is reasonable to require that the MGCC price in Large IOU DF Rate Proposals must account for costs associated with both peak and flexible capacity needs during periods of grid stress."	Chapter 2
12	**D.25-08-049, COL 7:** "It is reasonable to direct the Large IOUs to propose a functional relationship between the peak MGCC price and net load that best balances strong price signals with revenue stability considerations."	Chapter 2
13	**D.25-08-049, COL 8:** "It is reasonable to require that Large IOU DF Rate Proposals must also include a detailed evaluation to demonstrate how the proposed MGCC price function (1) does not unreasonably impact annual revenue recovery stability and (2) performs across a range of system conditions and years."	Chapter 2
14	**D.25-08-049, COL 9:** "It is reasonable to require that each Large IOU's MGCC price function evaluation should include a comparison of revenue recovery variability with alternative functional approaches."	Chapter 2

Line No.	Requirement	Reference
15	**D.25-08-049, COL 10:** "It is reasonable to require that each of the Large IOU's implementation of flex MGCC components should be based on each IOU's current allocation of marginal generation capacity costs to flexible capacity: a. For IOUs with existing flexible capacity allocations: If a non-zero percentage of MGCC has been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as SCE, where 40% of the total MGCC is allocated to flexible capacity), then it is reasonable that each IOU's DF Rate Proposal should include a flexible MGCC price component that is calibrated to recover a similar proportion of the MGCC value being used for DF rate design purposes. This MGCC value may be either from the most recently adopted ACC model, or the calculated MGCC value from an IOU's latest GRC Phase 2 proceeding testimony. IOU applications may use the flexible MGCC price design that is a function of the 3-hoursystem net load ramp as proposed by Energy Division and TeMix in the Working Group report. b. For IOUs without existing flexible capacity allocations: If a percentage of MGCC has not been allocated to flexible capacity in an IOU's most recent GRC Phase 2 proceeding (such as PG&E and SDG&E), then it is reasonable to require that such IOUs should propose a reasonable nonzero percentage to allocated to flexible capacity for DF rates in their DF Rate Proposals. The IOU's DF rate proposal should include a flexible MGCC price component that is calibrated to recover this proposed proportion of the MGCC value being used for DF rate design purposes. The IOUs should follow the guidance detailed regarding the design of the flexible MGCC price function (i.e., use of the flexible MGCC price design that is a function of the 3-hour system net load ramp as proposed by Energy Division and TeMix in the Working Group report). If an IOU does not propose a non-zero percentage of MGCC that should be allocated to flexibility capacity in DF rates in their DF Rate Proposals, then the IOU must provide analysis and a rationale that supports this determination, a method to address system ramping costs in DF Rate Proposals and assess the impact on renewable curtailment."	Chapter 2
16	**D.25-08-049, COL 11:** "It is reasonable to require that MGCC values used for Large IOU DF Rate Proposals should be consistent with the rate design directives adopted by the Commission under the Net Billing Tariff."	Chapter 2
17	**D.25-08-049, COL 12:** "It is reasonable to require that Large IOU DF Rate Proposals should incorporate the statewide MGCC value from the most recently adopted ACC model as January 1, 2026 which is derived from IRP modeling and cost assumptions."	Chapter 2
18	**D.25-08-049, COL 13:** "It is reasonable to provide the Large IOUs with the option to submit the proposed MGCC values from their most recent GRC Phase 2 applications (i.e. non-settled MGCC values that were calculated, submitted in testimony, and supported by workpapers), or the settled MGCC values that were adopted by the Commission in their most recent GRC Phase 2 applications, and the MGCC values that is an input to the ACC in their DF Rate Proposals."	Chapter 2
19	**D.25-08-049, COL 14:** "It is reasonable to require that initial Large IOU DF Rate Proposals should include an MDCC that is location-based and appropriately recovers the costs that vary with customer class and voltage level."	Chapter 2

Line No.	Requirement	Reference
20	**D.25-08-049, COL 15:** "It is reasonable to require Large IOUs to limit non-coincident demand charges in DF Rate Proposals to only recover demonstrably customer-specific non-peak distribution costs that are clearly shown to be caused by individual customer non-coincident demand rather than system or circuit peak loads."	Chapter 2
21	**D.25-08-049, COL 16:** "It is reasonable to require the Large IOUs to include an hourly transmission capacity price component in DF Rate Proposals."	Chapter 2
22	**D.25-08-049, COL 17:** "The Large IOUs should describe a plan to design MTCC price components that will be incorporated in their respective DF Rate Proposals."	Chapter 2
23	**D.25-08-049, COL 18:** "It is reasonable to require that in DF Rate Proposals, marginal prices for import rates should be scaled to recover the EPMC allocated portion of each IOU's total authorized revenue requirement (i.e., the EPMC allocated portion of "non-marginal" costs)."	See discussion of compliance challenges in Chapter 2
24	**D.25-08-049, COL 19:** "It is reasonable to provide the IOUs with two options for recovering non-marginal costs in import DF Rate Proposals: (1) using an EPMC scalar applied to time-varying marginal prices, or (2) using a time-differentiated Revenue Neutral Adder."	See discussion of compliance challenges in Chapter 2
25	**D.25-08-049, COL 20:** "It is reasonable to direct the Large IOUs to provide a detailed accounting of the elements comprising non-marginal generation costs, describe how revenues associated with those costs have evolved over time, and identify the long-term cost-drivers of non-marginal generation costs in their DF Rate Proposals."	See discussion of compliance challenges in Chapter 2
26	**D.25-08-049, COL 21:** "It is reasonable to require that the Large IOUs recover revenue categories that are not already recovered through the scaling of time-varying rate components (e.g., marginal customer access costs, non-peak marginal distribution capacity costs, other non-marginal costs) through alternate rate design elements in DF Rate Proposals to ensure that DF rates are revenue neutral."	Chapter 2
27	**D.25-08-049, COL 23:** "It is reasonable for the Large IOUs to propose conducting a marginal distribution cost study in their respective GRC Phase 2 proceedings to propose MDCCs and escalation scalars."	Chapter 2
28	**D.25-08-049, COL 24:** "If a Large IOU elects to include export compensation in a DF Rate Proposal, then it is reasonable to require that the proposal use asymmetric pricing, where export rates are based solely on unscaled marginal costs, while import rates include a scalar or a time-differentiated Revenue Neutral Adder to recover the EPMC-scaled portion of an IOU's authorized revenue requirement."	Chapter 2
29	**D.25-08-049, COL 25:** "It is reasonable to require Large IOUs to provide customer protection options in their DF Rate Proposals for bill and revenue stability to enable wider adoption of hourly DF rates without creating large structural bill impacts for both participants and non-participants."	Chapter 2
30	**D.25-08-049, COL 26:** "It is reasonable to require that the Large IOUs must include appropriate customer protection options that provide bill and revenue stability benefits for each customer class in their DF Rate Proposals."	Chapter 2
31	**D.25-08-049, COL 27:** "It is reasonable to permit the Large IOUs to include Transactive Programs in their DF Rate Proposals that only allow forward transactions to be offered no earlier than a week ahead to certain DF rate customers that can plan and schedule their energy use."	Chapter 2

Line No.	Requirement	Reference
32	**D.25-08-049, COL 28:** "It is reasonable to require that customer protection options in Large IOU DF Rate Proposals must: a) ensure stability of revenue recovery and minimize structural rate impacts; b) reduce the impact of non-coincident peak demand charges and flat volumetric charges on customer incentives to respond to dynamic prices; and c) protect customers against extended periods of high dynamic prices which cannot be mitigated by load shift."	Chapter 2
33	**D.25-08-049, COL 29:** "It is reasonable to provide the Large IOUs with flexibility to design customer-class appropriate protection options in DF Rate Proposals and identify the following as viable approaches: a) two-part subscription tariffs, which may differ in design for different customer classes to account for differences in customer acceptance and load characteristics; b) an approach similar to VCE's price-adjustment, where the average of the dynamic price is adjusted with a scalar offset to recover the same revenues as a class-specific tariff; c) transactive pricing programs where forward transactions are offered no earlier than on a week-ahead basis to minimize potential forecasting risks, and offered to large customers that can plan and schedule their energy use; and d) bill limiters or bill protection, with clear demonstration of how cost shifts will be minimized and price incentives preserved."	Chapter 2
34	**D.25-08-049, COL 30:** "It is reasonable to require that all Large IOU DF Rate Proposals include the following analysis for any proposed customer protection option: a) estimated customer bill impacts such as those generated by the LBNL subscription design tool developed as part of the Working Group process; b) rate and revenue impacts for both participants and non-participants; c) potential for cost shifting from participants to non-participants; and d) whether incentives to respond to dynamic prices will be impacted, for example when a customer reaches their bill limit within a billing period."	Chapter 2
35	**D.25-08-049, COL 31:** "PG&E and SCE should each propose in their DF Rate Proposals how their own Expanded Pilots will consider and resolve the following questions: a) how DF rates can be designed to be user-friendly; b) how to identify and address the needs of low-income and DAC customers that may have an interest in subscribing to DF rates; and c) how to mitigate the impact of dynamic rates on low-income and DAC customers."	Chapter 2
36	**D.25-08-049, COL 34:** "It is reasonable to require the Large IOU's DF Rate Proposals to include a detailed description regarding how the Large IOUs will collaborate with CCAs on various features of DF rates and DF rate programs, including but not limited to: a) developing generation and distribution components and customer bill protection and management elements of DF rates, such as subscription design and transactive options; b) creating and launching LSE DF programs with IOU DF programs, to utilize lessons learned from IOU DF pilots and ME&O efforts and foster customer understanding of both bundled and unbundled DF rate offerings; and c) ensuring that LSE DF rates conform with CEC LMS requirements."	Chapter 3

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REAL-TIME PRICING AND

LOAD MANAGEMENT STANDARD REQUIREMENTS

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
REAL-TIME PRICING AND LOAD MANAGEMENT STANDARD REQUIREMENTS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E or the Utility) presents its supplemental proposal for a “Real-Time Pricing” (RTP) rate that would provide an optional set of hourly prices to customers on specified schedules, on a day-ahead basis.[1] This dynamic rate would have different rate levels for every hour and change on a daily basis to reflect the current conditions, both at the system level and at a localized distribution level. RTP rates are designed to reflect the Utility’s costs in a more granular and accurate manner than traditional Time-of-Use (TOU) rates and aim to reward customers for load response that reduces costs for the system and reduces greenhouse gas emissions.

Our proposal for this rate is responsive to regulatory directives from both the California Energy Commission (CEC) through the agency’s Load Management Standards (LMS),[2] as well as guidance provided by the California Public Utilities Commission (CPUC or Commission).[3] Along with the CEC, the CPUC, utilities, and intervenors in CPUC proceedings have provided considerable thought leadership around RTP rates for customers of California’s large electric Investor-Owned Utilities (IOU), namely: PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company. PG&E’s current proposal builds on CEC and CPUC guidance provided over the last few years.

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1 Throughout this chapter, the terms “RTP rates” and “dynamic rates” are used interchangeably and both refer to the same concept.

2 California Public Resources Code, § 25403.5 and California Code of Regulations, Tit. 20, Div. 2, Ch. 4, Art. 5, §§ 1621-1623.

3 Specifically, guidance articulated in Decisions (D.) 25-08-049, D.23-04-040, and the CPUC, Energy Division, Advanced Strategies for Demand Flexibility Management and Customer Distributed Energy Resource Compensation, Energy Division White Paper and Staff Proposal (California Flexible Unified Signal for Energy (CalFUSE) White Paper) (June 22, 2022).

PG&E has been working with interested stakeholders on these complex topics for several years. PG&E wants to acknowledge that RTP is the most complex rate design that any California utility has ever proposed by a long shot, both in terms of its sheer number of interconnected and interdependent components, and regulatory history. Therefore, we respectfully request that all parties keep this in mind, especially when thinking about how customers might understand and interact with these rates.

Implementation for the proposed supplemental RTP rate design presented here is addressed in Exhibit (PG&E-5), Chapter 4.

B. Summary of Proposals

PG&E proposes to utilize some of the existing rate designs from both the PG&E Hourly Flex Pricing (HFP) Pilots authorized in D.24-01-032[4] and the Phase II Vehicle-to-Grid Integration (VGI) Pilots[5] for future RTP rates, adjusted for some feedback received from those pilots, and modified by the guidance given in D.25-08-049. Given that D.25-08-049 required PG&E to submit this Supplemental RTP Testimony within only 60 days, this chapter represents PG&E's best effort to provide updated designs and analyses within that time limit. However, PG&E will need to submit Q3 2027 Updated Supplemental RTP Testimony, which is described in Chapter 4 of this exhibit, as new learnings from the Hourly Flex Pricing (HFP) pilots are developed and additional time is spent on analyses that require more than 60 days.[6]

For example, PG&E is presenting some new analysis here that attempts to assess price responsiveness as a function of rate design. The new analysis reveals some hidden dangers of extreme price differentials that warrants a deeper look. PG&E will continue to research and analyze potential RTP designs in the coming months and years.

The main features of PG&E's proposed Supplemental RTP rates include:

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4 D.24-01-032, p. 83, Ordering Paragraph (OP) 1. Pilots ordered in D.24-01-032 are referred to as the "Expanded Pilots."

5 Resolution (Res.) E-5326 (July 11, 2024), PG&E Advice Letter (AL) 6694-E and Supplemental AL 6694-E-A request approval of rate structures and methodology for avoiding double compensation for the Emergency Load Reduction Program for vehicle grid integration pilots, pursuant to Res.E-5192, pp. 24-25, OPs 1-5.

6 See Chapter 4, for more details.

- A day ahead hourly generation rate for bundled customers designed to collect Marginal Energy Costs (MEC), line losses, and Marginal Generation Capacity Costs (MGCC). The MGCCs will be allocated using the scarcity pricing concept to the various hours of the year using the sigmoidal function developed for the Day-Ahead Real-Time Pricing rates and approved in D.22-08-002.[7] For unbundled customers, Community Choice Aggregators (CCA) will have the option to customize the coefficients of the MEC, line loss, and MGCC formulas and/or apply a modifier. PG&E is working with interested CCAs to provide options to develop more customized dynamic generation rates for their customers if necessary. However, such customizations beyond the structure of PG&E's generation RTP rate design will need to be funded directly by the requesting CCA. CCAs that want to use a different generation marginal RTP price for their unbundled customers may also contract with another entity to develop that price and calculate their unbundled customer's generation RTP bill. Current eligibility for unbundled customers depends on whether the customer's CCA elects to participate by offering a generation RTP rate. However, once RTP rates have been built into the billing system, PG&E plans to offer its distribution & transmission RTP to unbundled customers, even if the customer's CCA does not offer a generation RTP rate. See Exhibit (PG&E-5), Chapter 3 for more information about LSE coordination.
- A day-ahead hourly distribution rate designed to collect primary distribution capacity costs. The hourly prices will vary depending on the location of the customer and will be determined using the scarcity pricing concept, with prices dependent on the forecasted load on a representative circuit with similar load characteristics as the customer's circuit. It will use a sigmoidal pricing function similar to that used for PG&E's CPUC-adopted MGCC.

[7] D.22-08-002, p. 25, OP 2.

- A transmission rate equal to the transmission rate on the customer's Otherwise Applicable Tariff (OAT) until a different dynamic version is approved at the Federal Energy Regulatory Commission (FERC).[8]
- Non-marginal costs will be added to the rate for delivered energy in order to make it revenue neutral to retail rates. This will take the form of a Revenue Neutral Adder (RNA) that will vary by rate schedule and sometimes by TOU period.
- An optional subscription component that collects revenue equal to the OAT rates applied to a predefined, customer-specific load profile. This component helps protect the customer from bill volatility because the dynamic components are only applied to deviations from this load profile.

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8 PG&E is currently researching and developing what should go into an hourly transmission rate component. As outlined in PG&E's LMS Compliance Plan, substantial research still needs to be done to design a dynamic transmission signal that accurately reflects the scarcity concept. PG&E's current plan is to propose an hourly transmission rate component to the FERC in Q3 of 2026, for implementation on January 1, 2027. PG&E's Revised Compliance Plan for the LMS (Jan. 9, 2025), CEC Docket No. 23-LMS-01, TN# 262235 (docketed Mar. 18, 2025), available at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-lms-01> (accessed Oct. 7, 2025).

TABLE 2-1
SUMMARY OF PROPOSED RTP ELEMENTS

Line No.	Proposed Item	Summary of Proposed Changes Compared to Existing Pilots	Discussed in Section
1	MEC	None	D
2	MEC Losses	Losses proportional to the square of PG&E load.	E
3	MGCC	None	F
4	Marginal Flexible Capacity Costs	None	G
5	Marginal Distribution Capacity Cost (MDCC)	A revision to the maximum price for the sigmoidal function.	H
6	Marginal Transmission Costs	No formal proposal yet.	I
7	Non-Marginal Costs	Non-marginal costs included in the dynamic signal for delivered energy, likely through a schedule-specific adder. More analysis is needed to consider other options.	J
8	Annual Marginal Cost Updates	Annual updates are optional and PG&E is unsure how often it will update. PG&E will follow D.25-08-049 guidance if needed.	K
9	Export Compensation	None	L
10	Subscription Protection	Offer customers an optional subscription based on their usage profile prior to enrollment. No scaling is needed. Usage profiles may be updated after several years. Other subscription options are under consideration.	M
11	Forward Transactions	Determine if applicability to other classes should be expanded after gaining pilot experience.	M
12	Bill Protection	Offer bill protection only to Residential customers for their first year.	M
13	Eligibility	Change the eligibility requirements of E-ELEC to allow RTP participants without any specific technology.	P

The proposed RTP rates would not be able to be part of PG&E's billing system until our Billing Modernization Initiative (BMI) is completed expected in Q4 2029 or later, and they could be programmed into the modernized billing system in 2030 or later, and launched in 2031 or later. Until that time, the RTP rate elements, RTP subscription element, and RTP transactive element (if any), would be implemented using shadow billing, as described in Exhibit (PG&E-5), Chapter 4.[9]

C. Organization of the Rest of This Chapter and Witness Responsibilities

The remainder of this chapter is organized as follows:

- Sections D to J – Detail key rate design elements of the proposal;
- Section K – Discusses how PG&E proposes to update marginal cost parameters on an annual basis between General Rate Case (GRC) cases;
- Section L – Discusses export compensation;
- Section M – Discusses customer protection options including subscriptions and forward transactions;
- Section N – Discusses how demand charges will work in conjunction with RTP rates;
- Section O – Covers miscellaneous topics that may affect future RTP rate designs;
- Section P – Outlines which rate schedules are compatible with RTP;
- Section Q – Conclusion.

The witness responsibilities for this chapter are as follows:

- Tysen Streib – All sections of this chapter except for Section M.4;
- Iris Cheung – Section M.4.

D. MEC Design

The MEC will be equal to the California Independent System Operator (CAISO) hourly forecasts of day-ahead energy prices in dollars per megawatt-hour or cents per kilowatt-hour (¢/kWh) at the PG&E Default Load Aggregation Point (DLAP).

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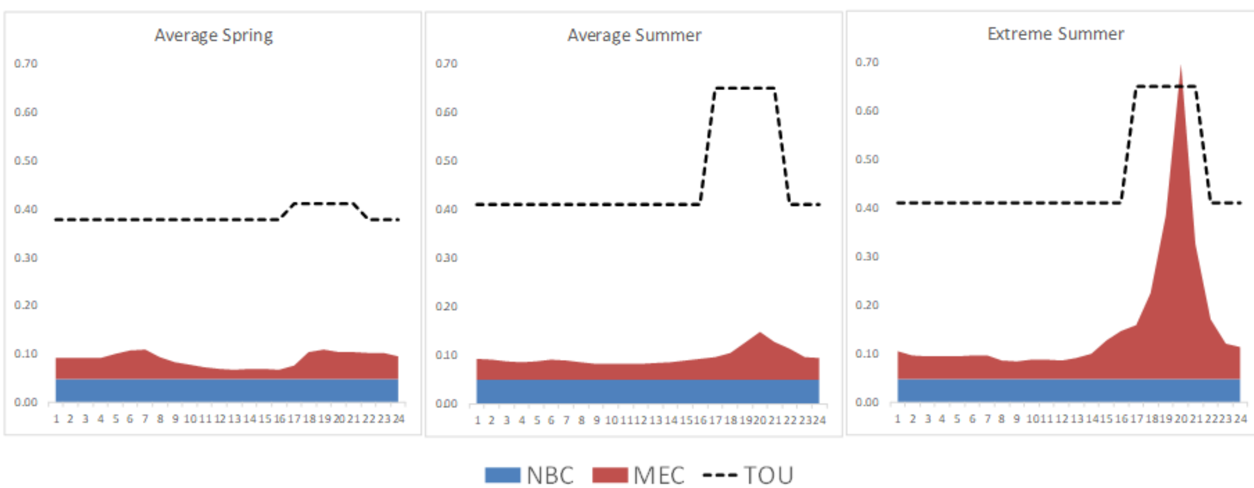
9 A "shadow bill" is calculated outside of PG&E's billing system in a separate rate calculation engine.

To help illustrate the effects of the various components of the dynamic rate, we will be building up several examples of the dynamic rate component by component for three different example days:

- A typical spring day (March 8, 2024);
- A typical summer day (July 18, 2024); and
- A 99th percentile[10] day (July 11, 2024).

The example will be for a residential customer so that we can initially ignore the effects of demand charges. A discussion of demand charges and their effect on the dynamic rate will be in Section N.

FIGURE 2-1
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER KILOWATT-HOUR (kWh))



For now, the first two layers of the different rate components contain just the Non-Bypassable Charges (NBC) and the MEC from the CAISO. The full proposed retail TOU rate (containing all rate components) is given as a reference. We can already see the low solar prices in the spring as well as the expensive peak on the hot day.

E. MEC Losses Design

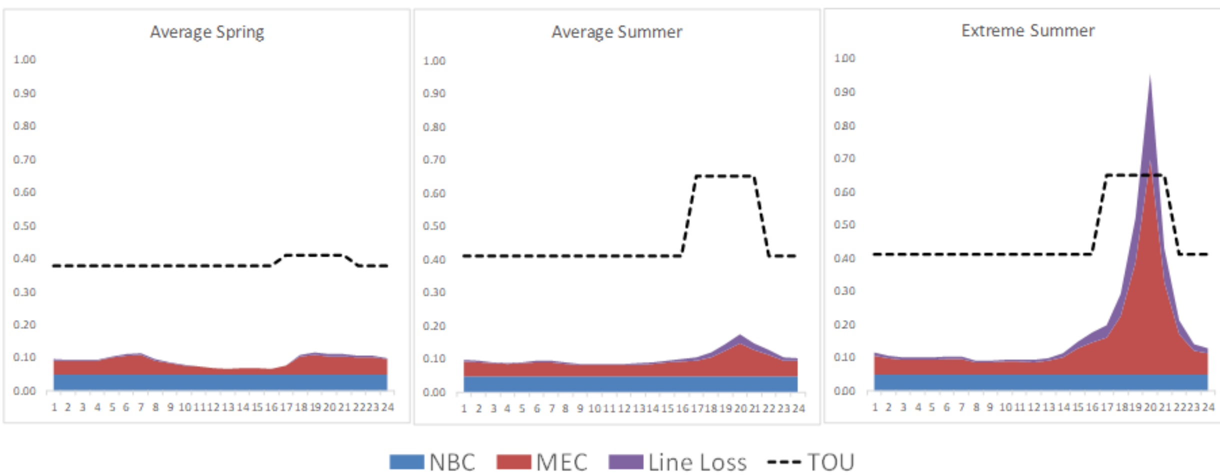
In the past, PG&E used a fixed Loss Factor assigned to the MEC. PG&E will modify the current fixed Loss Factor to one that varies non-linearly with the load. Transmission losses are quadratic in nature. $Losses = I^2R$, where I is

10 This is the day with the 7th highest prices in a 2-year period (2023-2024).

proportional to the power flow, resulting in $Losses \propto Power^2$. An updated loss factor will be based on marginal load factor, and more reflective of real-world loss. PG&E intends to work with IOUs to finalize a methodology for the loss factor, that accurately represents the actual load procurement after accounting for the line losses. For now, we will model the losses to be proportional to the square of all PG&E load.

Note that the scale is changing for each of these graphs in order to accommodate the high prices.

FIGURE 2-2
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



F. MGCC Design

In accordance with Demand Flexibility Principle #3,[11] the MGCC portion of the RTP rate will be a day ahead hourly rate that allocates an approved MGCC annual value. Following the guidance of D.25-08-049, this MGCC value is usually:

1) PG&E's proposed MGCC value during an ongoing GRC Phase II, or
2) The approved MGCC value following a GRC Phase II Decision.

These values may be updated annually following a decision, as described further in Section K below.

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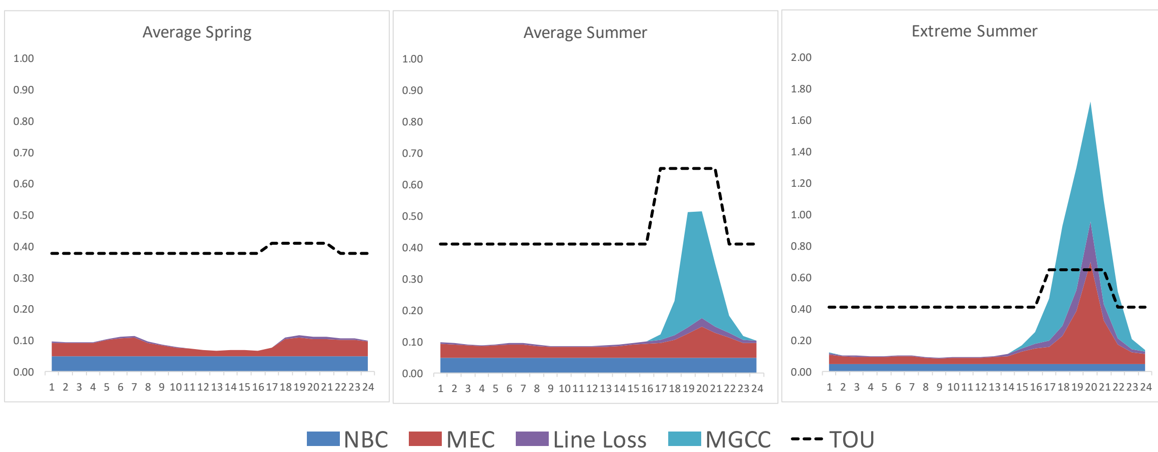
[11] D.23 04-040, p. 37, OP 2.

The allocation of the annual MGCC to various hours will be determined based on the MGCC Study, which was included in PG&E's 2020 GRC Phase II, and is included here as Attachment A. This essentially allocates capacity dollars to hours in proportion to the likelihood of the CAISO calling an alert, warning, or emergency. This allocation method was a collaboration between PG&E and multiple intervenor parties and represents the best cost-based allocation method that PG&E has developed.

FIGURE 2-3
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



With the addition of MGCC the scale of these three scenarios has been changed, as the prices are already exceeding $1.60/kWh.

D.25-08-049 also requires the IOUs show the MGCC values from the Avoided Cost Calculator (ACC), even if the IOU is not proposing to use that value in its rates.[12] When averaged over the same time period that PG&E uses to calculate its MGCC, the ACC provides an MGCC value that is about $140/kilowatt (kW)-year. Compared to PG&E's proposed value of $86.51, using the ACC value would provide MGCC values that are 1.6 times as big.

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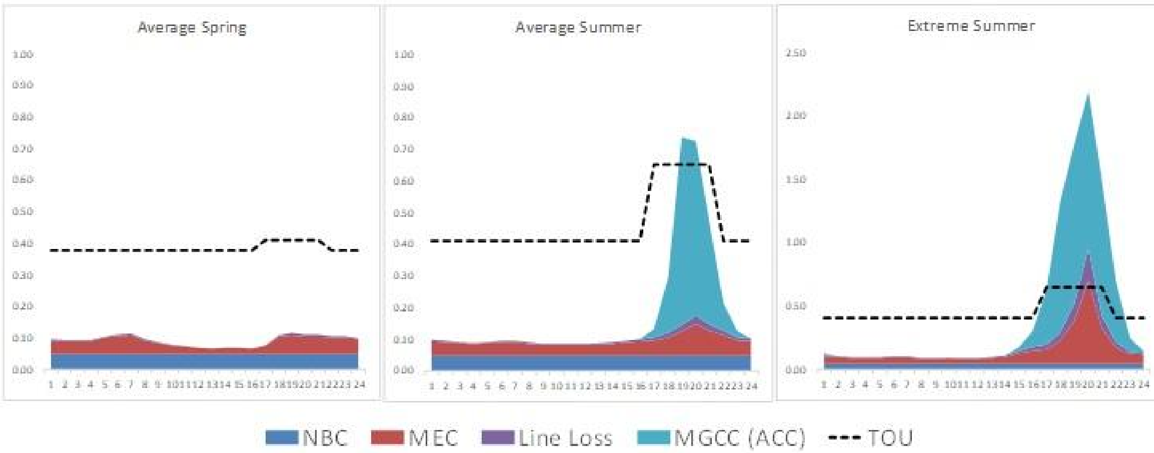
12 D.25-08-049, p. 141, Conclusion of Law (COL) 13.

FIGURE 2-4
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



PG&E notes that if D.25-08-049's Equal Percent of Marginal Cost (EPMC) scaling method is used (as discussed in Section J below), the choice of MGCC value becomes mostly irrelevant because the non-marginal costs will scale the prices to the same point in either case. The choice of MGCC is still relevant for exports and if EPMC scaling is not applied.

All of the IOUs and many intervenor groups argued against the use of the ACC value on the basis that the ACC was not developed in a rate-setting procedure, did not have the same rigor and analysis that is involved in a GRC-derived MGCC, and contains elements that are not marginal costs. PG&E believes that its own MGCC value derived in this proceeding is a more accurate representation of its costs and will use that in its proposals.

Since dynamic generation represents the vast majority of the value of RTP in most hours and more than half of PG&E's load is unbundled and served by CCAs, the involvement and engagement of CCAs will be critical to the success of RTP. PG&E has been working closely with CCAs over the last several years to get them involved and ready to propose RTP generation rates in PG&E's pilots. This involvement will be on-going, including in the pilots.

To support unbundled customers, PG&E intends to continue working with CCAs to use PG&E's structure for the generation RTP element, with the flexibility to modify the coefficients of the MGCC formulas and/or apply a modifier. We have also worked with CCAs to provide options to develop more customized dynamic generation rates for their customers if necessary. However, such customizations beyond the basic structure of the PG&E RTP generation rate design will need to be funded directly by the requesting CCA. CCAs that want to use a different generation marginal RTP price for their unbundled customers may also contract with another entity to develop that price and calculate their unbundled customer's generation RTP bill.

G. Flexible Capacity Cost Design

D.25-08-049 states:[13]

> If an IOU does not propose a non-zero percentage of MGCC that should be allocated to flexibility capacity in DF rates in their DF Rate Proposals, then the IOU must provide analysis and a rationale that supports this determination, a method to address system ramping costs in DF Rate Proposals, and assess the impact on renewable curtailment.

PG&E is proposing a zero percentage of MGCC be dedicated to flexibility capacity and provides the following rationale. The rationale for including the flex-cost suggested in D.25-08-049 is to improve system reliability and renewable integration. However, these facets hold true only with a stagnancy of battery storage deployment, which is in contradiction of reality. California has been increasing battery deployment at rates far exceeding forecasts, and that has led to several predictions (on which D.25-08-049 is based) to be factually incorrect. Let us look at them one by one:

D.25-08-049 claims that "duck curve" is exacerbated with increased renewable (solar) integration.[14] While this has been true in the past, it is not true anymore. CAISO data is showing that the duck belly has started to reach an asymptote, despite record increases in solar integration. While the increase in demand has played a minor role in this observation, the major factor driving this trend has been significant recent increases in battery storage which provides the opportunity to charge-up during low-cost/high solar production hours, as illustrated in the charts below.

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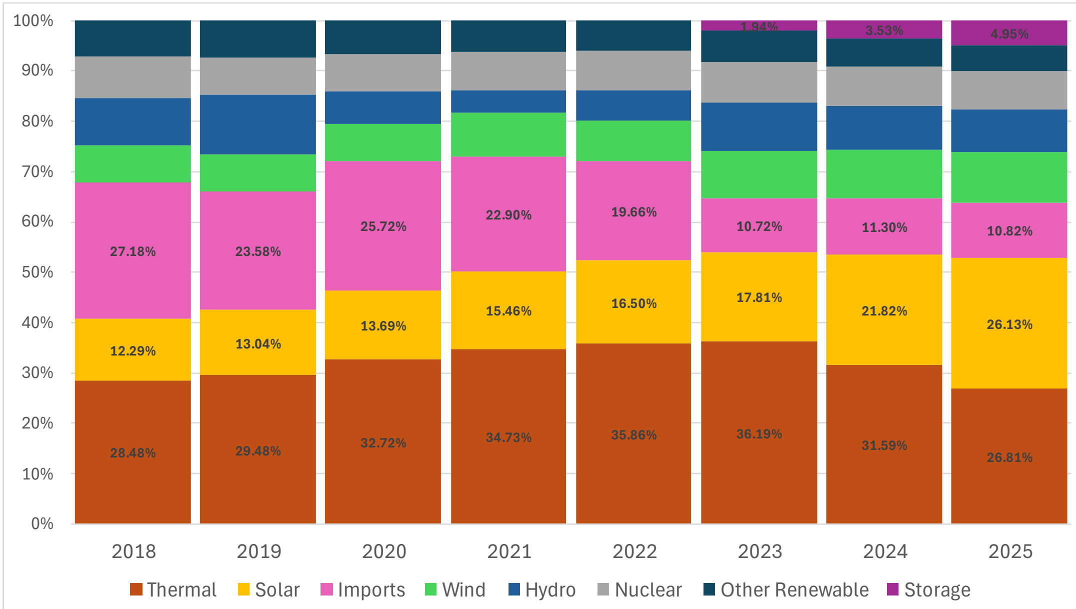
[13] D.25-08-049, p. 140, COL 10(b).

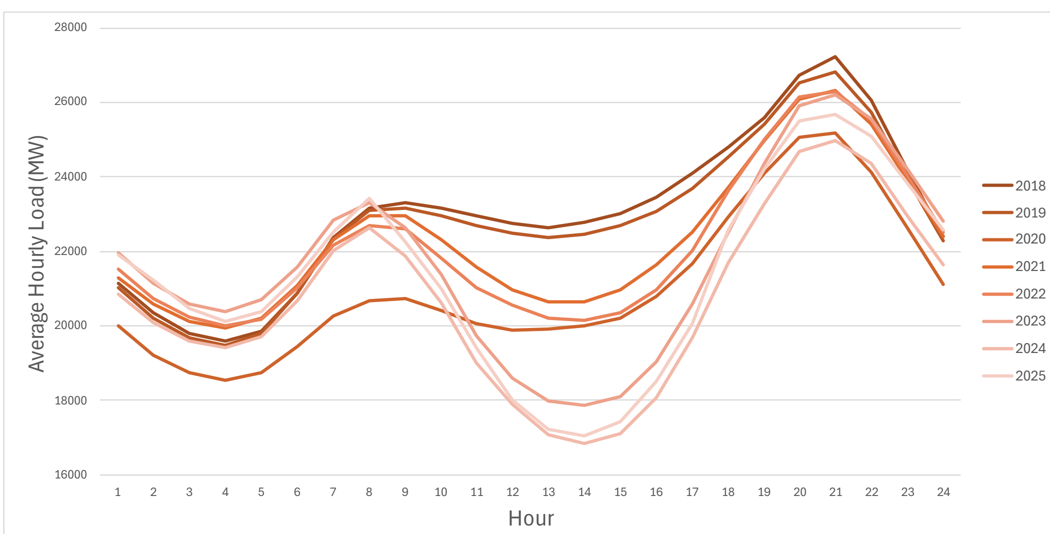
[14] D.25-08-049, p. 45.

FIGURE 2-5
CAISO GENERATION BY TECH TYPE 2018-2025



As seen above, even though solar adoption has continued to increase, California is also now seeing a significant increase in battery storage. The combination of these two factors has for the past three years resulted in a stabilizing duck curve as seen in the overlapping lighter colored curves for 2023-2025 shown in the figure below:

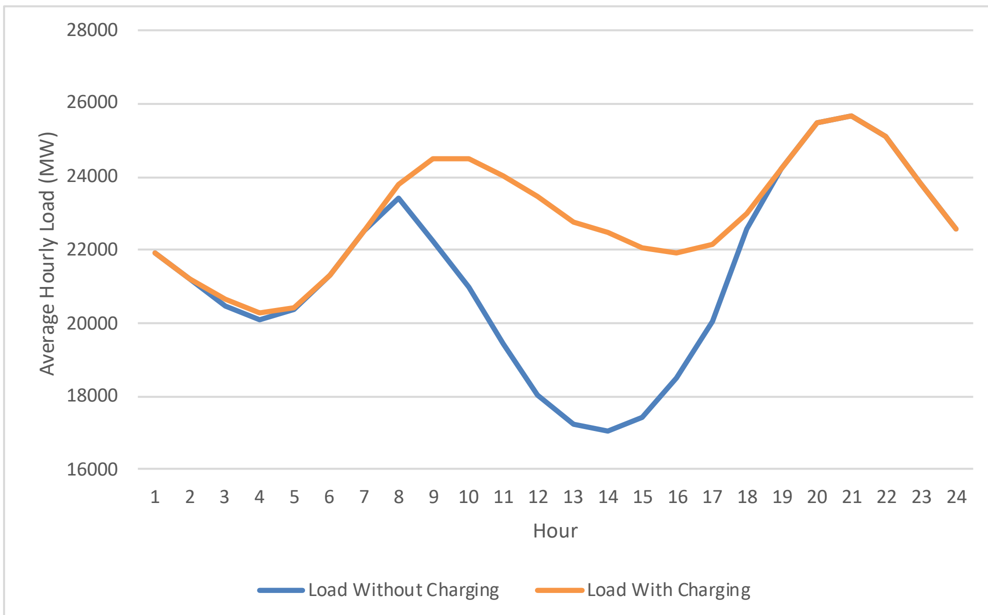
FIGURE 2-6
APRIL AVERAGE HOURLY DEMAND (WITHOUT BATTERY CHARGING)



In fact, battery deployment has so outweighed renewable integration, that the demand inclusive of battery charging follows a significantly flatter duck belly in 2024 and especially 2025, expected to further flatten as more battery storage continued to be deployed.

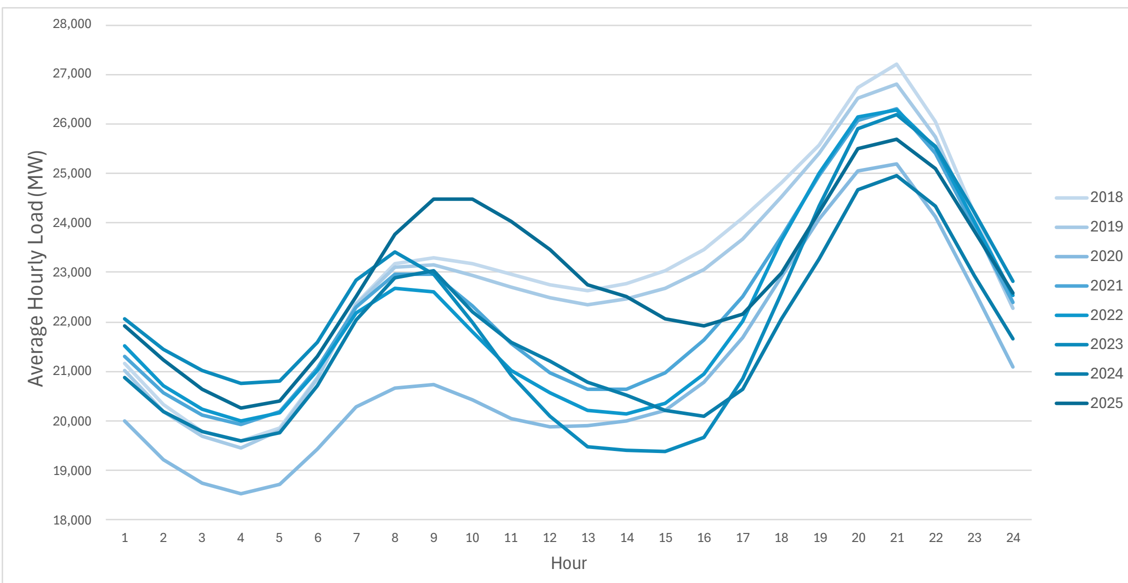
The following specific hourly profile for April 2025 shows how drastically battery charging flattens the duck curve.

FIGURE 2-7
APRIL 2025 AVERAGE HOURLY DEMAND AND BATTERY CHARGING



The other rationale provided for the inclusion of flex-capacity is the necessity of ramping resources during periods of rapid changes in net load. The flex marginal cost is a relic of a period when natural gas generators were solely responsible to respond to the sudden increase in load, and because of their inability to ramp quickly enough, one would need to dispatch more generators, resulting in an added cost. This is certainly not the case anymore. While natural gas generators continue to play a significant part in ramping up (and down) the load outside of solar hours, their ramp has become shallower (and not steeper) with the increase in battery deployment. Indeed, in PG&E's 2020 GRC Phase II, the CPUC determined that the marginal generation unit is 4-hour battery storage rather than the historically-used combined cycle combustion turbine.[15] What this means is that, because of a less steep ramp up (and down) period, PG&E does not foresee an increase in gas generators merely to fill the ramp requirements. On the other hand, PG&E foresees a further slowing down of the ramp, as battery deployment continues at the current breakneck speed. As opposed to natural gas generators, which have significant startup and variable operations and maintenance (O&M) (fuel) costs, batteries operate with negligible O&M costs, necessitating no additional flex costs.

FIGURE 2-8
APRIL AVERAGE HOURLY LOAD 2018-2025



Overall, looking into a future with abundant solar and battery storage in California, PG&E believes California's duck curve will continue to become shallower (beyond the current steady profile), such that flex-capacity cost will remain unjustified. Overall, having a non-zero flex-capacity amount may increase the price differential beyond the reality of markets, forcing a less accurate dynamic rate design. Thus, PG&E proposes to include no flexible capacity in its MGCC design.

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[15] D.21-11-016, p. 159, Finding of Fact 23 and 24.

H. MDCC Design

1. Introduction

A dynamic distribution component was not proposed in PG&E's 2020 GRC Phase II RTP design. During design discussions with intervenors, a dynamic distribution component was considered and ultimately rejected because the magnitude of the price signal would be much smaller than generation and the determination of a location-specific distribution cost would be much more complex.

Over the last several years of discussion, and in light of the CPUC's dynamic rate guidance and CEC developments, PG&E decided to include a distribution component in its HFP pilots and includes a very similar distribution design here. While PG&E still believes that dynamic distribution will have a much smaller price signal on average, there may be times when a dynamic signal may be useful.

In accordance with Demand Flexibility Principle #3, PG&E is proposing a dynamic distribution signal that collects Primary Capacity marginal costs, is location specific, and is priced based on the forecasted hourly load of a representative circuit with a similar load profile to the customer's circuit.

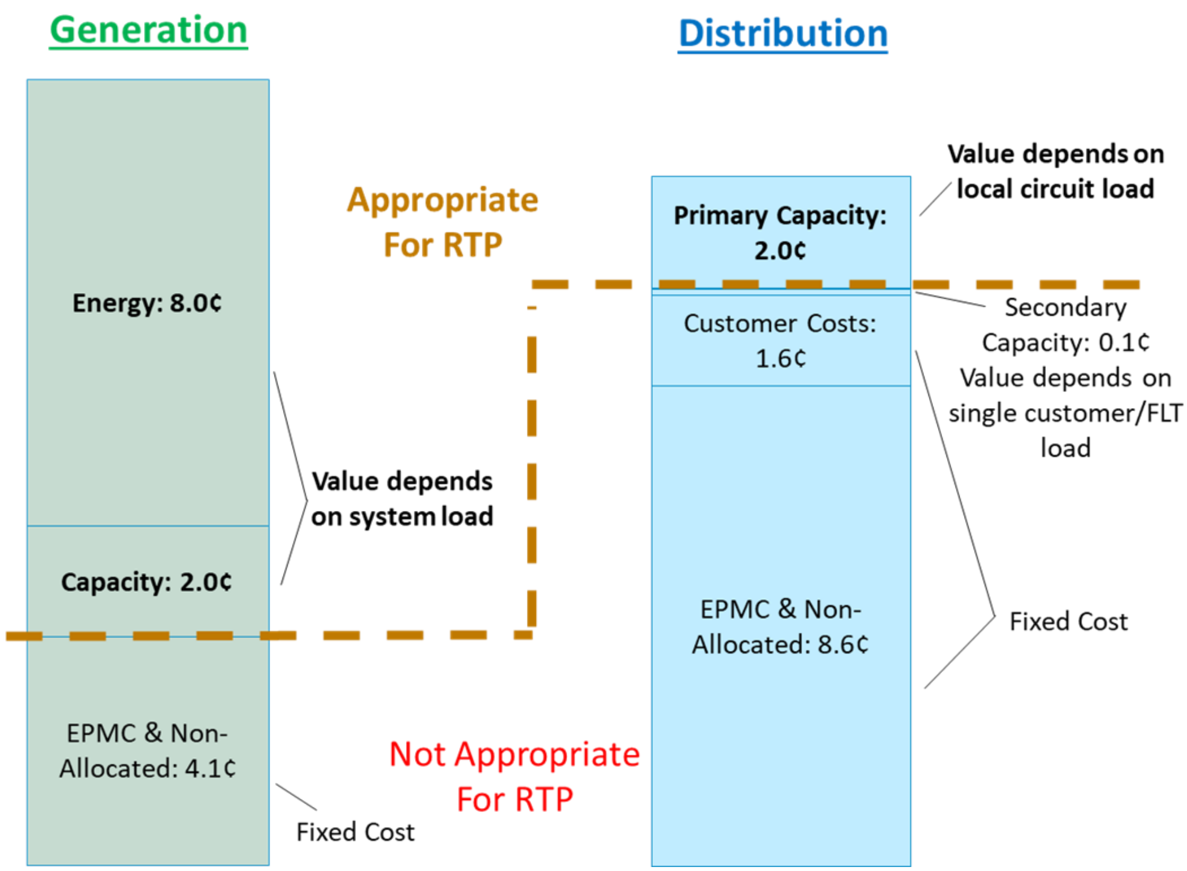
2. Distribution Capacity Costs and Appropriate Cost Drivers

Distribution is fundamentally different from generation because the cost drivers for each are completely different. Distribution costs are largely fixed, and the remaining variable costs depend only on the capacity requirements at the customer/Final Line Transformer (FLT)[16] level or at a circuit level—there are no costs that vary with energy usage (i.e., all costs vary by kW capacity, not by kWh). Generation, on the other hand, has a lot of pure energy costs, plus some capacity costs at the system level, with relatively few fixed costs. This means that the value for RTP comes almost entirely from generation. There is some distribution grid benefit that can be captured from local grid conditions, but it is generally much smaller than the generation benefit.

[16] Please see Exhibit (PG&E-2), Chapters 6-7 for details about FLTs and other Distribution marginal cost topics.

Below is an illustration of those differences based on the marginal cost data from Exhibit (PG&E-2) and using present rates from July 1, 2024. Costs are converted to a ¢/kWh figure for comparability; this does not imply that an energy charge is appropriate for all these costs.

FIGURE 2-9
AVERAGE NON-NET ENERGY METERING (NEM) COSTS
FOR DISTRIBUTION AND GENERATION
(CENTS PER kWh)



Generation is comparatively easy to create a real-time price for—the rates can be set at a system level and because the price can be set per hour, capacity charges can be converted into energy without a loss of cost causation because the capacity needs are systemwide and the peak timing is coincident. EPMC multipliers and non-allocated costs would ideally be collected through a fixed charge from a cost causation principle but are being added to the dynamic rate through the mechanism described in Section J, as directed by D.25-08-049.

In contrast, distribution has many more complexities when trying to design an RTP rate. First, Primary Capacity costs have a cost driver that is dependent on the load on the customer's circuit.[17] Since circuits typically serve thousands of customers, the circuit load is fairly independent of any one particular customer's load patterns. Therefore, circuit level forecasts can be developed and RTP prices can be developed from that forecasted circuit load profile. However, even though circuit forecasts are developed for distribution planning purposes, developing the rates associated with each circuit is not easy. PG&E has over 3,000 circuits in its service territory, which would ideally require deriving 3,000 separate sets of 24-hourly prices based on 3,000 different forecasts of distribution capacity planning needs. Thus, any rate that is developed based on the forecast would likely not reflect the actual primary capacity costs if not refreshed frequently. Additionally, circuit-level forecasting models are not as robust as system-level forecasts, leading to larger forecast errors.

Secondary Capacity costs are for distribution equipment that is much closer to the customer.[18] The cost driver for these components is load at the customer's FLT, which in many cases is just a single customer's load. In order to make a cost-based RTP rate for these components, that rate would essentially have a price that is dependent on the customer's own load - in other words, a demand charge. Therefore, it is not possible to have

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17 *Ibid*.

18 Previous discussions of distribution costs also included New Business Primary Capacity Costs in the same category as Secondary Capacity Costs. For this case, PG&E is now calling these costs Line Extension Costs and are allocating them on a per-customer basis, rather than on a per-kW basis.

cost-based day-ahead prices created for these components as there is nothing for the customer to react to. Unlike generation, these capacity charges cannot be converted to hourly prices since the high-priced hours are simply the hours in which the customer itself uses the most electricity. If a customer shifts their peak load to another time of day, the costs are still there and are simply allocated to the shifted load. This is why many cost-based rate designs use noncoincident demand charges; they are the best tool to reflect the costs that customers put on the system—and they do not depend on the time of day. These costs do not have an hourly profile that could be included in an RTP rate.

Finally, Distribution Customer Costs, the EPMC multiplier, and non-allocated revenues are all fixed costs that do not depend on customer usage and therefore PG&E does not believe they are appropriate for an RTP rate. When a customer uses an extra kWh of energy, the added cost to the Utility is just the marginal cost, not the EPMC scaled cost. If the customer reduces load because of an EPMC scaled signal, the Utility loses more revenue than it saves in costs. EPMC scaling of price signals therefore creates negative contribution to margin and a cost shift.

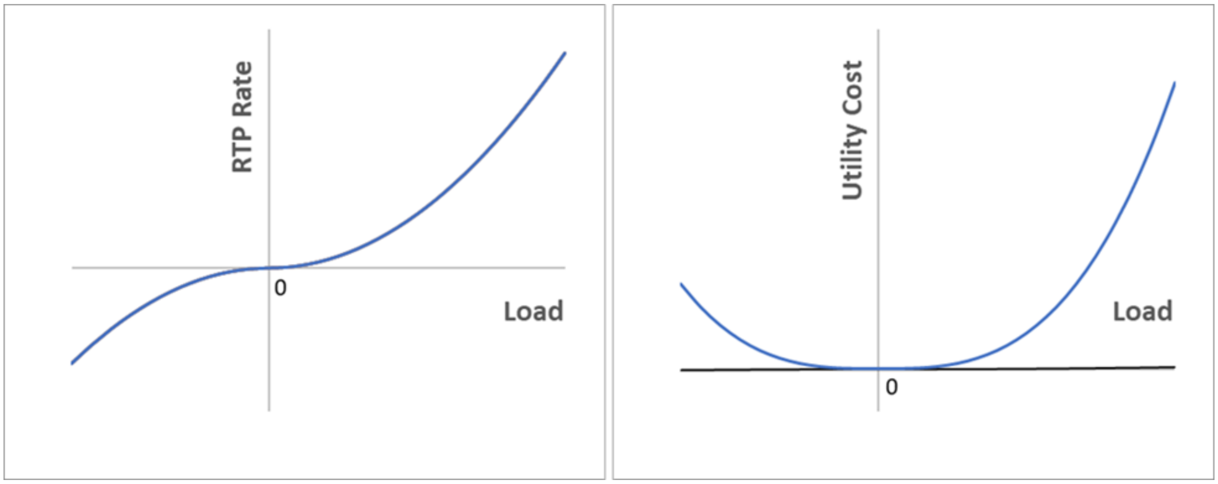
PG&E notes that in the settlement agreement for RTP approved in D.22-08-002, multiple intervening parties met and discussed cost causation for about a year, over 30 separate settlement discussions. The final proposal from that intensive collaboration was an RTP signal that did not include EPMC scaling.

However, D.25-08-049's guidance purports to require EPMC (or similar) scaling, so these costs may need be included in the dynamic price signal. More discussion on this can be found in Section J.

3. Distribution RTP Price Curves

The CalFUSE framework provides an example of how distribution RTP rates can be designed. Under CalFUSE, the RTP prices in each hour are derived using scarcity pricing where the price increases with higher demand on the grid, encouraging conservation during times of grid stress. The charts below illustrate how these price curves typically look, as well as how that relates to the Utility's cost.

FIGURE 2-10
CalFUSE MODEL OF DISTRIBUTION RTP PRICE CURVES AND UTILITY COSTS



The Utility's cost for the circuit depends on the load on the circuit, but it does not matter which direction the electricity flows. If there is a large amount of on-site generation so that the overall load is negative (net exporting) then that has a local distribution cost (not a benefit), and that cost gets higher with additional exports. This is modeled by inverting the price signal when the load on the circuit is negative. During typical conditions when the circuit load is positive, the RTP price is positive (consumption is charged and exports receive a credit). However, during the hours when the entire circuit has negative load, the RTP price becomes negative (such that exports are charged and consumption is credited). This incentivizes the correct behavior because during these times additional exports increase circuit costs. This pricing mechanism supports Demand Flexibility Principle #6 and ensures that exporting technologies are rewarded appropriately.

The above price curves are one way of allocating Distribution Primary Capacity costs based upon circuit load. One could theoretically design a similar RTP rate for Secondary costs, but they would be dependent on load at the FLT, not load at the circuit. Unfortunately, as mentioned in the prior section, FLT load is usually just the customer's own load and therefore not something that can be forecast to give an RTP signal.

Given this limitation, PG&E sees three options regarding Secondary marginal costs in an RTP rate:

1) Include Secondary marginal costs with the Primary Capacity costs and model them as if they all varied by circuit load;
2) Treat Secondary as a marginal cost, but one that does not vary by circuit load (i.e., a fixed dollars-per-kilowatt-hour ($/kWh) adder); and
3) Treat Secondary costs as non-marginal.

Option 1 is the way distribution rates were designed for the first two years of the Valley Clean Energy (VCE) RTP pilot.[19] However, that pilot was implemented with limited time to design the rates, and after further consideration and analysis, PG&E does not believe this option is optimal. The main reason for this belief is that FLT load is often poorly correlated with circuit load. This is because FLTs typically only serve a small number of customers (or even a single customer) and therefore have load profiles much more sensitive to specific customer loads, compared to the circuit level load which reflects the diversity of all customers on the circuit. To illustrate this, Figure 2-11 below plots the Peak Capacity Allocation Factor (PCAF) hours[20] against FLT hours[21] for a sample circuit.

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19 PG&E AL 6495-E-A.

20 PCAF hours are hours in which the circuit-level load is 80 percent or more of the circuit's annual maximum load. Figure 2-11 plots 193 PCAF hours for the sample circuit.

21 FLT hours are hours with the maximum annual FLT load. Figure 2-11 plots the peak hours of 86 FLTs on the sample circuit.

FIGURE 2-11
COMPARISON OF PCAF AND FLT HOURS FOR A SAMPLE CIRCUIT

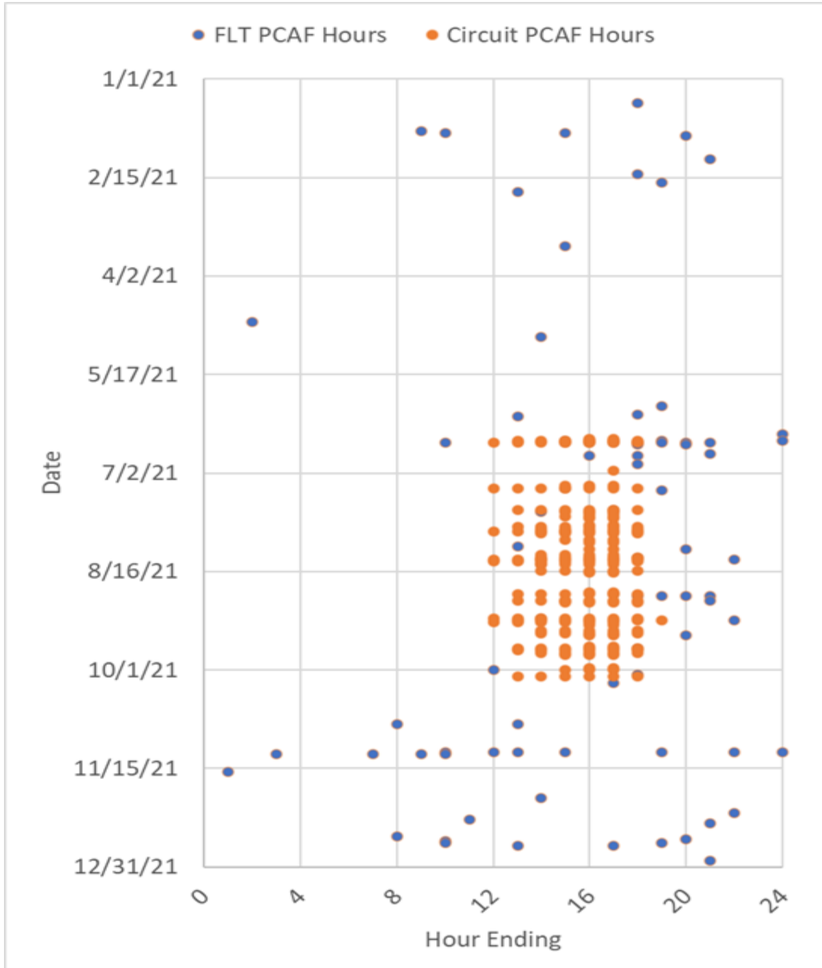
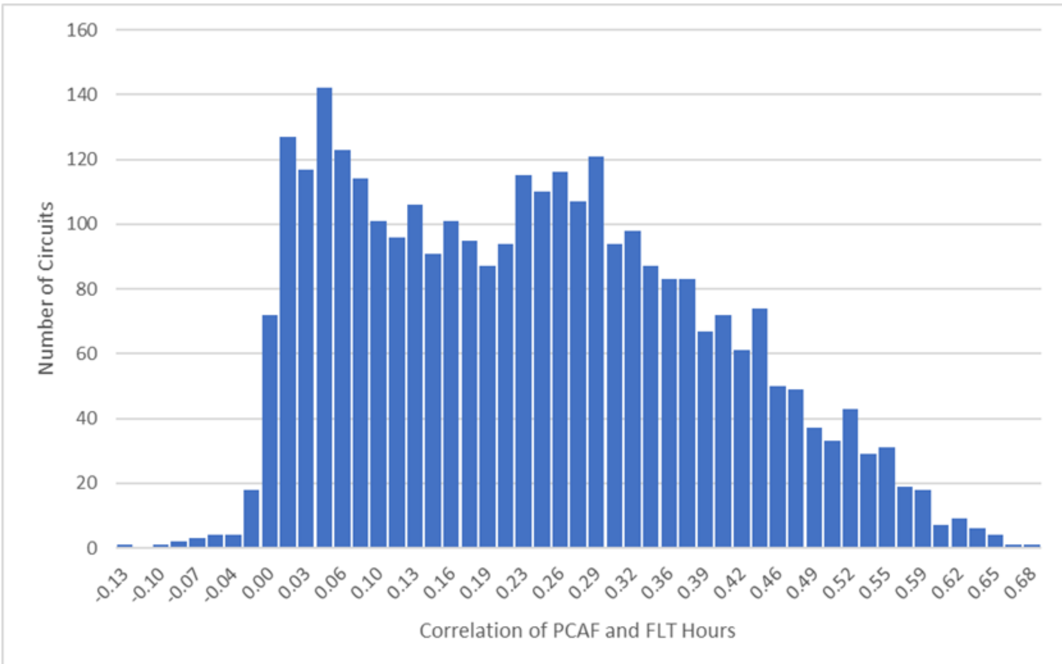


Figure 2-11 shows how PCAF hours on this circuit are tightly grouped, typically in the afternoon/evening hours during summer months, whereas the FLT peaks on this circuit can occur in any hour of the day, during any part of the year, with very little correlation to the PCAF hours. If we wanted to use the circuit load to allocate FLT costs, that would mean sending high price signals on the orange dots when the actual signals should be on the blue dots.

The actual correlation measurement of PCAF vs FLT hours on this circuit sample is 0.12 (very low). PG&E calculated the PCAF to FLT hour correlation for its 3,124 circuits and found that the average correlation is 0.22. A frequency distribution of the circuit-specific correlations is provided in Figure 2-12 below.

FIGURE 2-12
FREQUENCY DISTRIBUTION OF CORRELATION BETWEEN PCAF AND FLT HOURS BY CIRCUIT



To recap, PG&E does not recommend using Option 1, as it would send incorrect price signals and potentially increase system costs overall.

Option 2 acknowledges the marginal cost of the load, but decouples the price signal from the circuit load and treats it as a flat adder per kWh. This would be PG&E's preferred option if it were not for the fact that this would not appropriately value exports. Using a fixed adder for Secondary costs would not be appropriate for exports because exports actually increase utility costs for these components, rather than reducing them (i.e., the FLT costs actually look like the second diagram in Figure 2-10, above). Including these costs in the RTP rate would subtract a constant value from export compensation, so Option 2 is not ideal. PG&E recognizes that reducing the value of exports is the correct thing to do from a marginal cost perspective, but does not currently recommend this option, as it may discourage participation.

Option 3 is PG&E's proposal for RTP rates and collects Secondary costs as though they were non-marginal. PG&E's proposal is to collect maximum demand charges from those customers that have demand charges on their OAT. Therefore, this revenue is already removed from the non-marginal portion of the dynamic rate for any customer that has a maximum demand charge, and so this treatment only affects rate schedules without a maximum demand charge.

4. Scarcity Price Curve Equation

During the Demand Flexible (DF) Order Instituting Rulemaking (OIR), PG&E investigated many potential scarcity price curves including quadratic (and higher powers, with and without offsets), exponential, PCAF-like curves, and sigmoidal functions. After reviewing the resulting price distributions, PG&E concluded that the best function to use was a sigmoidal function, similar to what is used for the generation RTP signal. A sigmoidal function concentrates most of the price signal to the few hours when capacity is constrained most, but also provides a cap that prevents unlimited price increases. The coefficients for the sigmoidal function will vary from circuit to circuit, capturing the forecasted load characteristics, and capture the Primary Capacity marginal cost revenue. More details are in Section H.7, below.

5. Primary and Transmission Voltage Level Customers

Customers that take service at the Primary voltage level do not incur Secondary marginal costs, but they have the same Primary costs as Secondary level customers. Therefore, the RTP prices for Primary customers will be the same as for Secondary level customers, with the reduced costs reflected in non-marginal portion.

Transmission voltage customers do not have any MDCCs, which would lead to a distribution value of zero in all hours. All of a Transmission customer's distribution revenue will be collected though customer and demand charges.

6. Clustering of Circuits for Location Based Pricing

PG&E has more than 3,000 circuits in its service territory and developing hourly forecasts each day for every circuit would be a major computational and operational effort. Therefore, PG&E has started a clustering analysis in an attempt to group circuits with similar load profiles together so that a smaller number of RTP prices can be developed.

PG&E’s clustering analysis groups circuits into about 60 clusters, with an average of about 50 circuits per cluster. The raw hourly usage data for each circuit includes 24 hours for each of 365 days in a calendar year for a total of 8,760 hours. PG&E looked at the historical RTP prices that would have been developed for each circuit individually and then grouped together the circuits that have the most similar prices. As a result, circuits within a cluster share the same overall load characteristics, such as the timing of high-load versus low-load hours, ramp periods, etc., even if the underlying load magnitudes or geographic locations are different (i.e., a 5 megawatt (MW) circuit and 20 MW circuit can have the same load shape, and therefore be in the same cluster.). Clustering circuits in this manner means that a single RTP rate can be utilized for all the circuits within a cluster, vastly reducing the number of circuit level load forecasts to be modeled.

PG&E’s experience with clustering during the operation of the HFP Pilots reveals that it may also not be the ideal solution. Clusters are still operationally challenging to manage and there may be reduced alignment between a customer’s actual circuit and their representative circuit if frequent recalibrations are not employed. Frequent recalibrations bring their own challenges, such as increased analytic support and possible overcorrections if recent data history is given too much weight. PG&E will need to find the right balance between this clustering method, individual circuit forecasting, or some other topological aggregation to ensure prices accurately represent grid conditions, load modifications deliver value, and scalable operational processes are maintained.

7. Developing RTP Rates With Clustering

RTP hourly rate coefficients will be developed for each cluster. To do so, a single representative circuit (the circuit closest to the centroid of the cluster) will be selected from each cluster and used to calibrate the scarcity price curves. PG&E will forecast the loads for these representative circuits to be input into the scarcity price curves to develop a day ahead hourly RTP for each representative circuit. Lastly, the RTP for each representative circuit will apply to all customers/circuits in the representative circuit’s respective cluster.

While using the quadratic scarcity method to develop the rates in the VCE pilot, it was initially observed that the rates varied highly between circuits. This had to do with a fundamental assumption in the CalFUSE method[22] of scaling, which the following example clarifies:

Suppose that you have two circuits (Circuit A and Circuit B) that are identical and they both have a maximum capacity of 10 MW. The CalFUSE assumption is that they both should collect the same amount of revenue for marginal costs, based on a $/kW capacity cost. However, assume that Circuit A is highly utilized while Circuit B has low utilization. Since the revenue collected from both circuits is identical, Circuit B will have much higher RTP rates.

To rectify this inequity, PG&E proposed to change the scaling method in the VCE pilot so that every circuit collects the same average $/kWh rate, rather than trying to collect the correct capacity cost in each circuit. PG&E proposes to use the same scaling logic for these rates. Rates will still vary by location at different times of the day, but all circuits will collect the same average revenue and hopefully address many equity concerns.

PG&E has chosen a sigmoid functional form to calculate real-time prices. However, being non-linear, this function has coefficients that cannot be determined algebraically (i.e., with the usual "paper and pencil" method) and quickly results in a system of equations that cannot be solved easily. For this reason, PG&E has employed mathematical optimization with computers. The basic idea here is to guess values for the coefficients iteratively until it is possible to minimize an appropriately chosen error function, which actually measures quantitatively how far the current coefficients are from the optimal solution. Since RTP rates have the goal of recovering costs through revenue, this error function calculates a “revenue discrepancy,” the absolute difference between expected revenue and the actual revenue as calculated by the price function. Changes to the marginal cost will impact the total marginal cost revenue to collect and will create

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22 After seeing this effect, Energy Division changed its recommendation and now recommends using the method that PG&E is proposing.

proportional changes to the maximum price achievable in the sigmoid function.

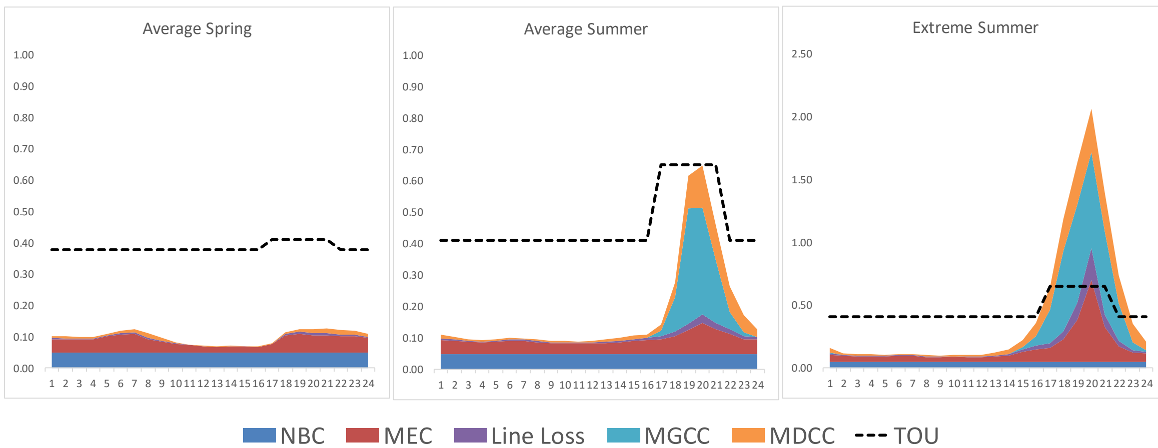
One of the parameters in the sigmoid function is the maximum price that the MDCC can reach. PG&E first determined a “high target” price that would be reached when the circuit is at its maximum historical load. To produce a cost-based target, PG&E looked at its PCAF weightings that are used to derive the MDCC; PG&E found that its highest PCAF hour in recent history provided an hourly MDCC value of about $0.37/kWh. However, setting the cap at $0.37 would not be ideal because the sigmoid curve would flatten out well before the historical max load and not provide much price sensitivity. Therefore, PG&E set the cap price to be 25 percent higher than the historical maximum, to provide additional sensitivity and to accommodate loads higher than the historical maximum.

While setting the “high target” price based on the historical max load for each circuit makes things more equitable between circuits, it does have the unintended consequence of creating false price variance on circuits that are well below their capacity constraints. Most circuits in PG&E’s territory never get above 50 percent of their capacity utilization, even under the most extreme conditions. Sending high price signals for these circuits just because the load is near the historical maximum does not make sense because there really is not a capacity constraint to avoid.

A better system would take capacity constraints into consideration, but that would mean very different behavior from circuit to circuit. Most circuits would have no dynamic distribution signal at all, or perhaps a small one. Circuits that are closer to their capacity limits would have a strong signal like we model here where the rate is zero most of the time but can get very high during high utilization. However, PG&E is keeping this system for now because there is a fear that customers on different circuits may have very different opportunities for load shifting savings. More research and analysis is needed to produce improved designs, but that was not possible within the 60-day time limit imposed on PG&E by D.25-08-049.

We will now look at how the MDCC layers on to our prior rate components. Although the actual distribution price will vary between circuits, we have chosen the “most typical” cluster in PG&E’s territory to provide example rates.

FIGURE 2-13
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



With these graphs it becomes very clear that the extra value added from distribution is usually small compared to generation.

8. Circuits With Very Few Customers

Some of the circuits in PG&E’s territory serve only a single customer or very few customers. This raises the same issue as occurs with FLT load—it will be extremely difficult to forecast load on a circuit if a majority of that load is going to be reacting to the prices derived from that load. This “feedback forecasting” may only be possible once PG&E has significant experience in dealing with RTP customers and builds more sophisticated models for how customers react to price signals. Therefore, as a temporary measure, PG&E proposes that any customer that is more than 15 percent of the total load on their circuit would not receive the distribution component of the RTP rate at this time, instead they will be charged their OAT distribution rate.

These customers would still receive the generation RTP signal and would still capture a majority of the value of RTP. When PG&E created its circuit analysis in 2023, it identified 3,948 customers that were more than 15 percent of their circuit’s total load.

9. Changing Circuit Configurations

The factors driving circuit level forecasts can vary significantly over short periods of time, resulting in forecasts that can quickly become outdated or stale. Circuit switching conditions change on a routine basis to manage events like maintenance and construction, outages, as well as environmental events like Public Safety Power Shutoff. This reduces how many customers are impacted from an outage by isolating, reconfiguring, and restoring power to healthy sections of a circuit, but these changes also increase load volatility significantly, making load forecasting impractical. SDG&E noted that it has considerable difficulty tracking which customers were on which circuits and that customers could switch circuits throughout the day.[23]

PG&E has also encountered several difficulties with changing circuit configurations in the current HFP pilots as well. One notable example had a circuit reach loads of 19 MW when the max historical load used for calibration was 12 MW. This caused the distribution portion of the dynamic rate to be maxed out almost 24 hours a day. The cause of this situation was a reconfiguration which switched three large industrial customers onto the representative circuit. While PG&E has a short-term fix for this situation by changing the circuit forecast to only consider customers that were on that circuit during calibration, this may not be an ideal long-term solution. Even with this fix, PG&E still sees distribution circuits changing load patterns/levels, causing circuits to drift out of calibration, and have abnormally high or low prices.

It will be undesirable if customers performed to a price signal that was contradictory to the actual circuit conditions. PG&E will need to determine the best way to handle forecasts and cluster assignments when these events occur. One potential solution is to forecast at a more aggregated level so that switching between circuits is still covered under the same aggregated umbrella. However, this process requires much more analysis and could take a while to develop.

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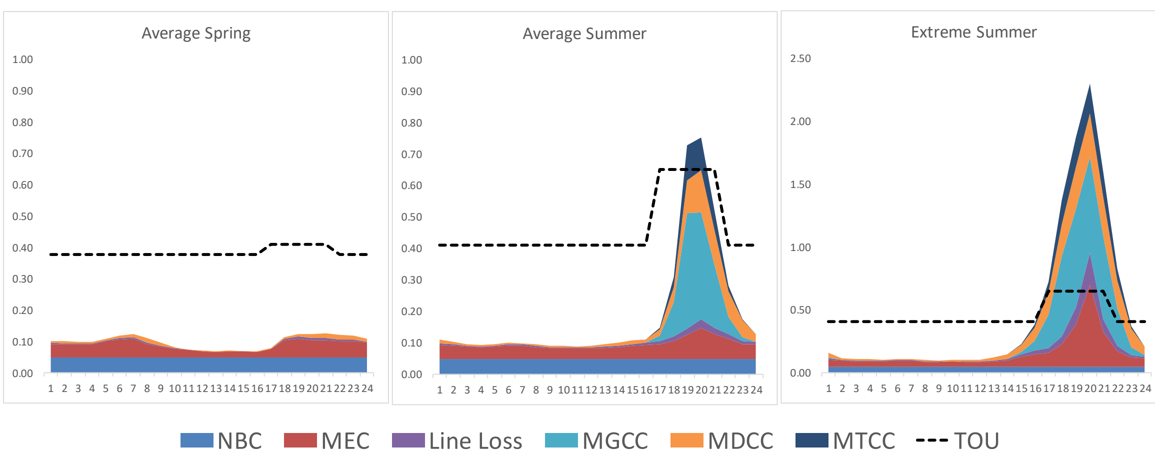
[23] R.22-07-005, CPUC, DF OIR, Track B Working Group Report (Oct. 11, 2023), p. 78.

I. Marginal Transmission Capacity Cost Design

PG&E is still developing its dynamic Marginal Transmission Capacity Cost (MTCC) rate design and is on track to file its rate design proposal with FERC to be effective by the CEC compliance date of January 1, 2027.

Although PG&E does not have a finalized, FERC-approved rate design for MTCC yet, for illustrative purposes of constructing these rate layers, PG&E is making the MTCC price proportional to the MGCC price as a rough proxy. PG&E's analysis into MTCC shows that approximately 14.4 percent of transmission investments are capacity related,[24] so the graphs below allocate 14.4 percent of the transmission revenue requirement proportionally to the MGCC allocation.

FIGURE 2-14
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



J. Non-Marginal Cost Design

PG&E's current pilot rates have a marginal-only dynamic price. This had the advantage that the price was symmetric for imports and exports, but it had the downside that accurate subscription levels were required to collect the non-marginal costs.

D.25-08-049 requires the IOUs to include the non-marginal costs into the dynamic rate in order to make it revenue neutral to the retail rate.[25] With a

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24 See workpapers supporting Exhibit (PG&E-2), Chapter 5.

25 D.25-08-049, COLs 18-19, pp. 141-142.

revenue neutral rate, there is now much more flexibility in subscription offerings including the possibility of subscribing to less than 100 percent of expected load, or to do away with subscriptions altogether.

This now brings us to the question: what is the best way to allocate these non-marginal costs? Non-marginal costs, by their very definition, do not vary with the amount of usage or the timing of that usage. Therefore, it seems that the most cost-based place to collect these costs is in a fixed charge (or subscription), and to keep them out of the dynamic rate. The CPUC's guidance in D.25-08-049 gave a different opinion, positing that non-marginal costs should be used to enhance the price differences between high- and low-cost hours.[26] While PG&E disagrees with this guidance, we will present various options below that use this methodology and examine the effects.

The preferred approach given by D.25-08-049 is EPMC scaling in order to bring up the marginal rate to the retail level. This would be done component by component, so if a rate component had an average marginal cost of $0.05/kWh and an average retail rate of $0.10, then the EPMC scaling is 2.0 and we would double the marginal rate in each hour to get a retail equivalent. I will refer to this approach as "Literal EPMC Scaling."

The graphs below show how Literal EPMC Scaling will affect our Residential dynamic rates. Keep in mind that with the addition of the non-marginal costs, these rates are now equivalent to retails rates and can be directly compared to the dashed lines representing the TOU rate.

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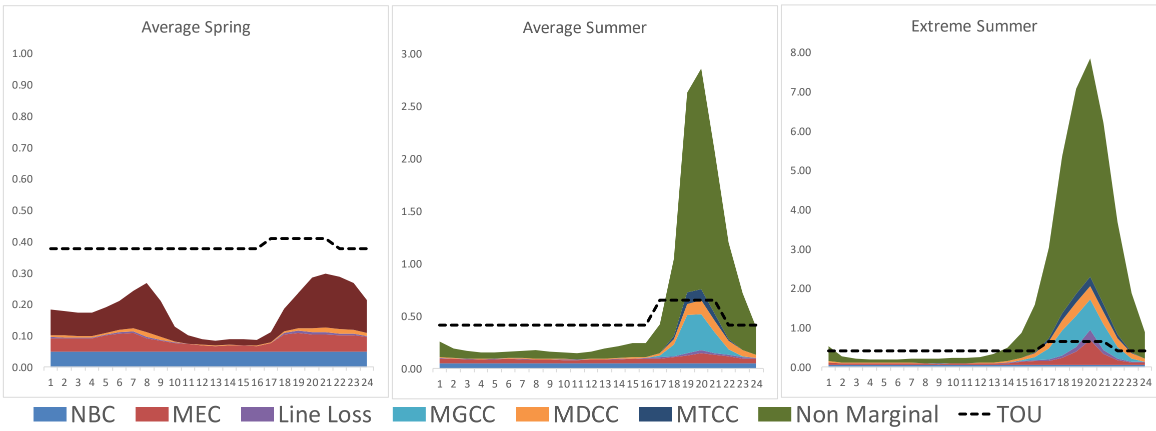
[26] D.25-08-049, pp. 77-80.

FIGURE 2-15
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



PG&E notes several potential issues with this method. We are now seeing prices of $3/kWh on a regular basis during the summer, even when the weather is normal. During the extreme prices on the right, we now see prices at $8/kWh on this example day; prices were even higher during some of the days in the 2-year sample we looked at. While we do not know how high prices should be during a heat wave, $8/kWh is excessive.

The EPMC scaling for the different components also varies widely—it is about 1.7 for generation, but 9.8 for distribution and 7.0 for transmission. This multiplies the price signal for distribution wildly and makes distribution more of a contributing factor than the generation component.

The other major issue is just how extremely concentrated a majority of the non-marginal costs are and how much of a seasonal difference it makes. Although PG&E's summer on-peak makes up only 7 percent of the hours in a year, it contains 49 percent of the non-marginal cost. By using this method, you are essentially putting most of the fixed cost responsibility onto those customers that cannot get away from summer peak usage. It makes enrolling in this rate option absolutely unthinkable for anyone in warm/hot climate zones and generally a "can't-lose" proposition for cooler climates. PG&E believes there will be extreme self-selection biases and a large number of free riders.

What if the CPUC were willing to live with these consequences in the name of increased load response? How much load shifting will happen and what kind of savings can we expect for the grid? To answer these questions, PG&E has constructed a simplified load-response model using price elasticities. While PG&E fully acknowledges that price elasticities are not constant from customer to customer or even from hour to hour, using constant elasticities will give us a ballpark price responsiveness and likely will not be too far from the truth. Using a more detailed model was not possible in the 60 days allowed by D.25-08-049 and an approximate answer will still provide significant insight.

The constant elasticity model looks at each hour and compares the dynamic price to the TOU price that the customer paid. It then predicts the adjusted load that the customer would have had, given the price difference. The model gathers statistics over the 2-year period of 2023-2024, which contains a cool and a warm weather year. The arc elasticity equation is:

$$E_d = \frac{(Q_2 - Q_1)}{(Q_2 + Q_1)/2} \div \frac{(P_2 - P_1)}{(P_2 + P_1)/2}$$

Where:

- E_d = Price elasticity of demand
- Q_1, Q_2 = Initial and new quantities demanded
- P_1, P_2 = Initial and new prices

We can use this equation to solve for Q2, which is the expected load used at the new price:

$$Q_2 = \frac{Q_1(-E_dP_1 + E_dP_2 + P_1 + P_2)}{E_dP_1 - E_dP_2 + P_1 + P_2}$$

There is no agreed upon value to use for the price elasticity of demand coefficient, however EPRI's 2021 RTP benchmarking report looked at 31 different elasticity studies and found that most measurements fell between -0.01 and -0.30 (although 68 percent of the measurements were between -0.01 and -0.10).[27] For purposes of discussion here, we call the value of -0.10 "average responsiveness" and -0.30 "optimistic responsiveness." While the median elasticity is smaller than -0.10, we conclude that it is reasonable to call -0.10 the average for customers who choose to take service on a dynamic rate.

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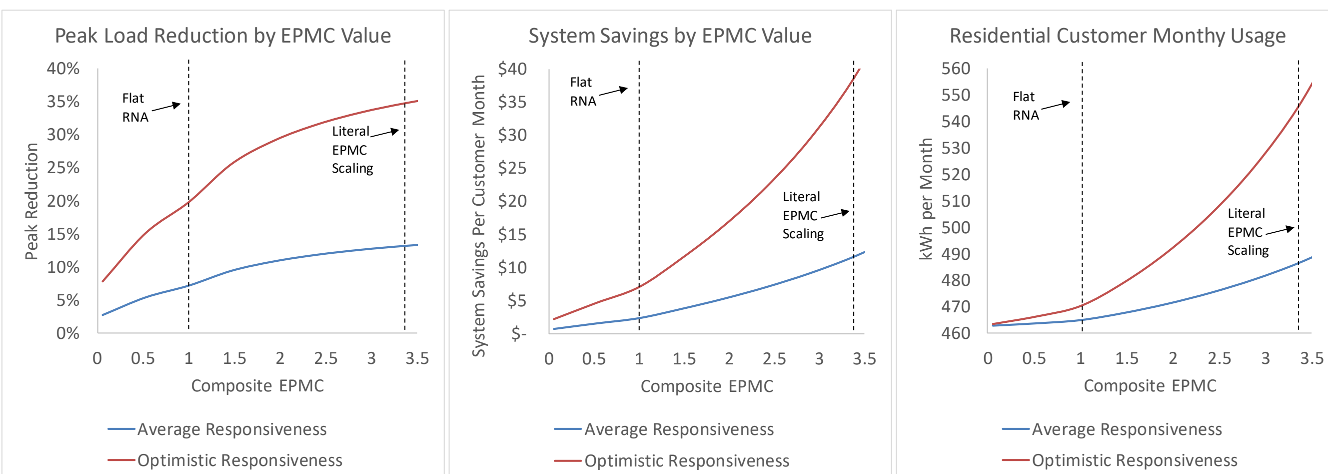
27 EPRI, Benchmarking Study of U.S. Regulated Utility RTP Programs, Architecture and Design (Mar. 2021), p. 5-2.

The EPMC scalar for residential customers varies by component, but when taken as a composite, it averages to about 3.4. We can therefore model different degrees of inclusion of EPMC scaling by varying this composite EPMC value and collecting the remaining revenue in a flat adder. Under this definition, a composite EPMC value of 3.4 represents full Literal EPMC scaling (with no adder), and a composite EPMC value of 1.0 represents no additional scaling and a flat RNA. If we take the hourly load profile of the average residential customer and then model the expected load shifts using the elasticity equation, we can model how much load shifting there will be at different values of composite EPMC.

FIGURE 2-16
PEAK LOAD REDUCTION, SYSTEM SAVINGS, AND CUSTOMER USAGE BY VARYING COMPOSITE EPMC VALUES

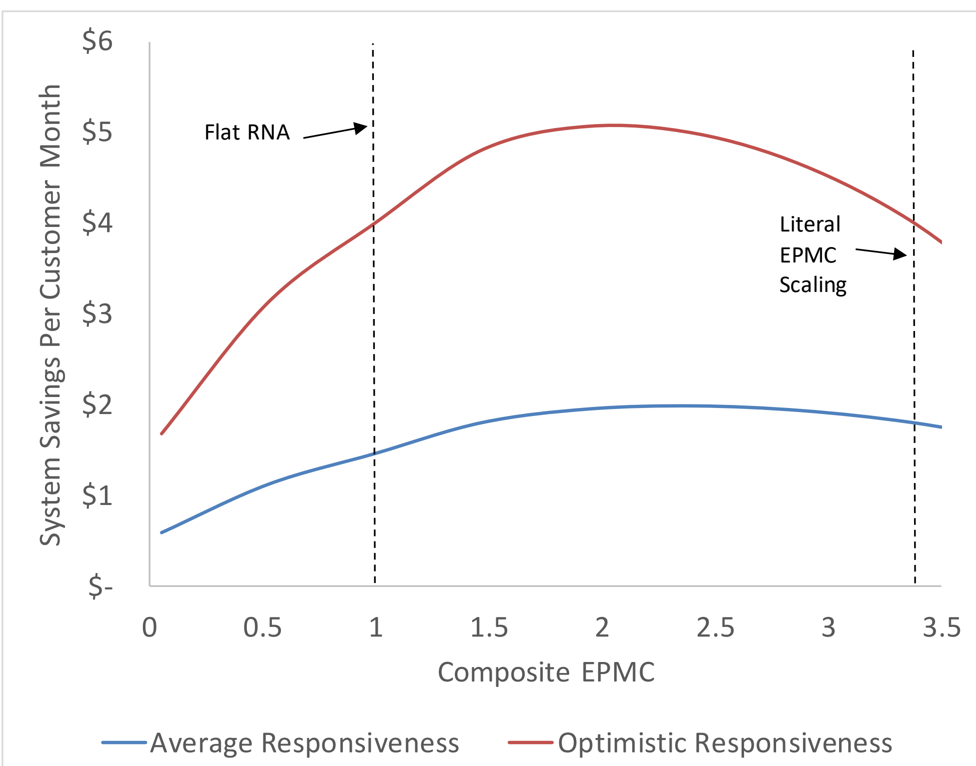


The graph on the left shows the load reduction in the top 100 hours of each year for both the average and optimistic responsiveness scenarios. It shows what we would expect—increasing the price differentiation during the most expensive hours helps lower peak usage, although there are diminishing returns at higher EPMC values because customers are only willing to shift so much, even if prices get very high. A composite EPMC value of less than 1.0 would represent a price signal that is dampened below marginal cost. These graphs show that some load reductions can still be obtained, even with a dampened signal.

However, focusing on peak reduction is not what is best for the system overall—the point is to reduce costs because dollars are what matter, not MWs. The middle graph shows how much the system costs are being lowered as we increase the EPMC factor. Again, we see increasing system savings with increasing EPMC. However, if you look closely at the underlying data, a vast majority of the system savings is due to overall increased usage by the customer.

The graph on the right shows that the elasticity model is predicting a fairly large overall load increase, so the customer is buying more electricity overall, even though they are avoiding the peak. The Optimistic Responsiveness scenario predicts an 18 percent increase in overall consumption with an EPMC of 3.4—which casts doubt on how likely it is that an Optimistic Responsiveness scenario would occur. Because overall load growth is not guaranteed, the following figure shows the system savings if you remove the savings due to increased overall load.

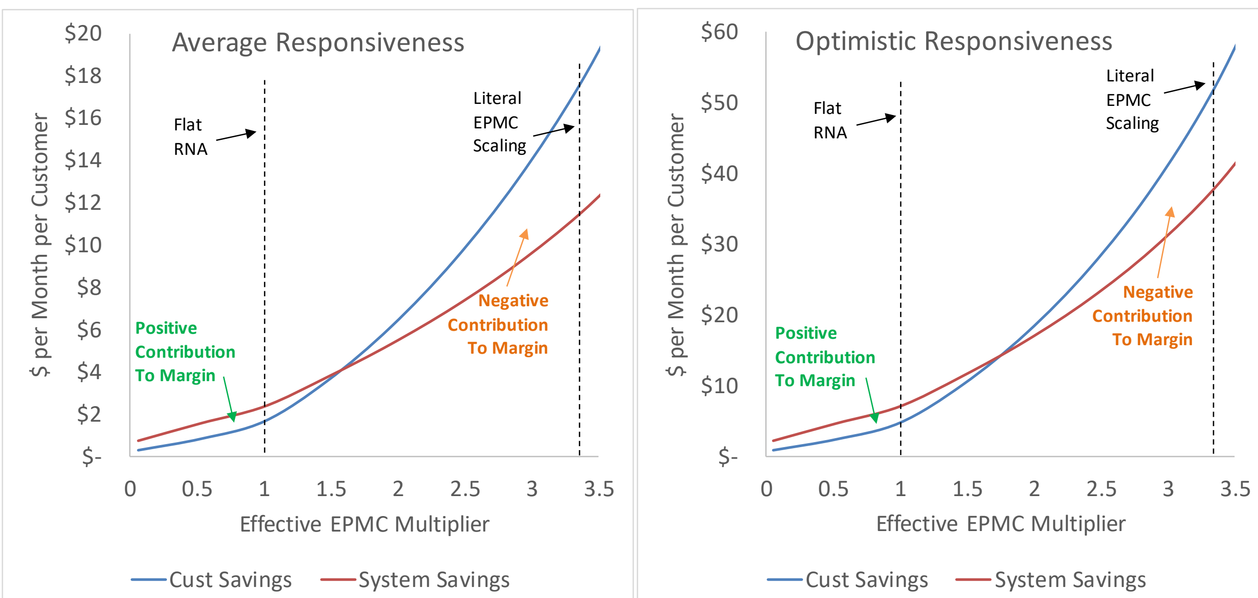
FIGURE 2-17
SYSTEM SAVINGS BY COMPOSITE EPMC VALUE
(NO LOAD GROWTH)



Removing the extra benefit from overall load growth reveals an interesting phenomenon—increasing the composite EPMC by more than about 2 is actually counterproductive. This is because putting ever more non-marginal costs into the peak starts lowering the rates in the partial peak. This incentivizes more consumption in these shoulder hours, which actually *increases* system costs.

However, this still is not the whole story. By shifting load, customers are reducing their bills, so PG&E will also have to pay for these incentives. When we overlay customer savings on top of system savings, we can get an insight into the contribution to margin for the system.

FIGURE 2-18
CUSTOMER SAVINGS, SYSTEM SAVINGS, AND CONTRIBUTION TO MARGIN BY VARYING COMPOSITE EPMC



These graphs overlay the customer savings on top of the system savings; the Average Responsiveness scenario on the left and Optimistic Responsiveness on the right. Customer savings grow faster than system savings when we increase the composite EPMC factor, but this money is not free, it comes from other customers. So, for the values of EPMC where system savings is greater than the customer savings, we see a positive contribution to margin and that creates downward rate pressure for all customers. At an EPMC value of about 1.6 the lines cross, which means that we are paying the RTP customer for all of the benefits they provide to the system and none of the benefits go to other customers. When EPMC goes higher than 1.6, as preferred by D.25-08-049, we pay customers more than the value they provide to the system, so non-participants end up with a cost shift. It looks like, if the most important goal was to reduce costs for customers, then an EPMC value of less than 1.0 would be the best, although a 1.0 value is still a pretty good level for achieving the cost-reduction goal.

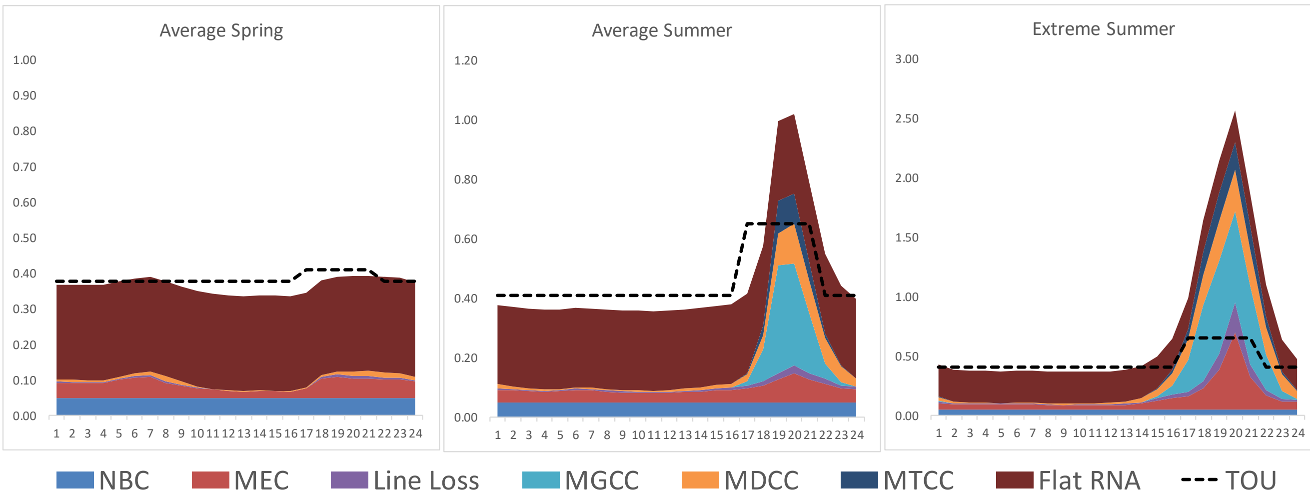
This analysis makes it clear that using a composite EPMC above 1.6 goes against the CPUC's Rate Design Principle #3: "Rates should be based on marginal cost and should not have a negative Contribution to Margin." It also seems clear that the appropriate EPMC factor should be much less than 1.6 so that not all of the system benefit gets paid to participating customers. *The purpose of dynamic rates is to provide benefits to all customers, not just those that sign up.*

PG&E notes that this contribution to marginal analysis does not include any operating costs. For any composite EPMC of 1.6 or greater, there is negative CTM at face value without any additional operational expenses. Including operational costs will make all scenarios less attractive. The exact amount of difference will depend on operational costs, which PG&E is still investigating and is discussed in more detail in Exhibit (PG&E-5), Chapter 5. At face value, EPMC scaling, as recommended by D.25-08-049, clearly is *not* cost effective for PG&E and should not be considered as a possible candidate for PG&E's RTP rate design.

PG&E is very concerned about the cost-shifts revealed by this analysis. If D.25-08-049's guidance were to be followed, it would result in a cost shift of at least $73 per customer-year for PG&E in the average scenario and $171 per customer-year in the optimistic scenario—just for residential customers.

The figures above show that PG&E's original RTP proposal of using a flat RNA, as approved in D.22-08-002, looks about optimal in terms of maximizing savings with a balance to both participants and non-participants. Examples of how a flat RNA would look are presented in the figure below.

FIGURE 2-19
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLAR PER kWh)



The use of a flat RNA still provides significant load reduction over TOU rates. The average summer graph in Figure 2-19 shows about a 3-to-1 peak-to-off-peak price ratio on a typical summer day. There is no need for EPMC scaling to provide extra incentives and the flat RNA helps avoid the unnecessary shifting between summer and winter months.

The guidance in D.25-08-049 indicates that, if PG&E does not want to use EPMC scaling, it can use a time-differentiated (not flat) RNA.[28] While PG&E is not opposed to the concept of a time-differentiated RNA in theory, the CPUC decision provided no guidance as to how the time-differentiation should be determined. The data also shows that any time-differentiation in the RNA is likely a step in the wrong direction, because it will push the composite EPMC above 1.0, thus reducing the benefits to non-participants, and potentially increasing overall system costs. However, even with a flat RNA as the default, PG&E would still time differentiate the RNA for those schedules that have average TOU differences that are larger than marginal cost so as to not reduce the price incentive.[29]

The guidance provided in D.25-08-049 represents conclusions that were reached mostly by thinking about price-responsiveness in the abstract, with the

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[28] D.24-08-049, pp. 141-142, COL 19.

[29] Typically BEV schedules and those with a peak demand charge.

mindset that “more is better.” PG&E believes that the Commission neither had evidence of how effective unscaled costs could be, nor did it have the data to show that EPMC scaling creates a negative contribution to margin and would raise costs for non-participants.

PG&E is now presenting evidence to show that there are diminishing returns for price-based responses and that very strong price signals can actually reduce benefits. Figures 2-16 through 2-19 above show that:

- A flat RNA provides about the same grid benefit (in $) that EPMC delivers outside of load growth;
- A flat RNA avoids massive cost shifts to non-participants that EPMC would introduce; and
- A flat RNA has fewer structural winners/losers and does not over-penalize hot climate zones.

The rationale in D.25-08-049 for not allowing a flat RNA was that:

> applying a flat adder uniformly across all time periods would dilute the cost differential between high and low-price periods, reducing customers' economic incentive to shift load.[30]

However, the data shown here reveals that there is not much dilution and that keeping high differentials actually creates more problems than it solves. Given that the CPUC did not have this data before it when it provided guidance in D.25-08-049, PG&E urges the Commission to adopt PG&E’s proposal to use a flat RNA in its dynamic rates.

PG&E has attempted to design an alternative proposal that still includes some EPMC scaling, but the approach contains serious flaws. One additional drawback of EPMC scaling to achieve revenue neutrality is that the multiplier would be different for each rate schedule. This is especially true for distribution costs where the ratio of average retail rate to primary marginal costs can vary widely from schedule to schedule. It is undesirable to have price scalings that vary so much from schedule to schedule. It does not have any rational basis and would cause customer confusion.

If PG&E were forced to use EPMC scaling, as an alternative to our primary proposal for a flat RNA, we would use a system-wide average EPMC value for

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[30] D.24-08-049, p. 78.

everyone and a smaller RNA to make up the difference. In addition, PG&E would adjust the revenues applicable to the EPMC in the following ways:

- For distribution, scaling would apply only the EPMC revenues associated with primary capacity marginal costs. The Literal EPMC method does not seem correct as it would also assign the EPMC portions of marginal customer costs and secondary capacity costs to the increased signal.
- For both distribution and generation, specially-allocated revenues would be excluded from the EPMC calculation. Distribution especially has many programs that are not traditional distribution infrastructure, so it makes sense to remove these from the multiplier.
  - D.25-08-049 asks the large IOUs to:

    > provide a detailed accounting of the elements comprising non-marginal generation costs, describe how revenues associated with those costs have evolved over time, and identify the long-term cost-drivers of non-marginal generation costs in their DF Rate Proposals.[31]

    PG&E is unable to provide this accounting and analysis within 60 days, but Exhibit (PG&E-5), Chapter 4 discusses PG&E's RTP Regulatory Roadmap and the possibility of providing additional testimony as part of its Q3 2027 Updated Supplemental RTP Testimony.
- For all components, revenue neutral scaling will be applied to summer and winter separately in order to mitigate structural winners/losers due to seasonal usage and reduce the concentration of non-marginal costs to the summer.

Using these adjustments, it looks like an alternative proposal of adjusted EPMC with a smaller RNA could be constructed for residential.

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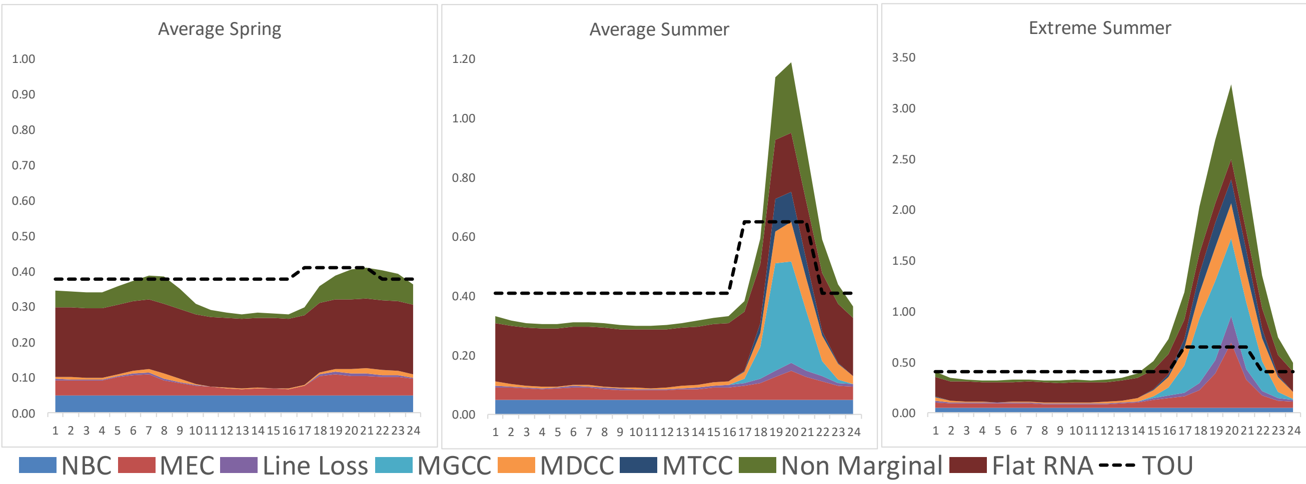
[31] D.25-08-049, p. 142, COL 20.

FIGURE 2-20
BUILDUP OF DYNAMIC COMPONENT PRICES FOR THREE EXAMPLE DAYS
(DOLLARS PER kWh)



This method has a composite EPMC value of about 1.4, is much more complicated to explain to customers, and produces only 38 percent of the contribution to margin of PG&E's preferred method.

For these reasons, PG&E cannot recommend using this alternative approach, but merely presents it to comply with the guidance in D.25-08-049. Rather, PG&E's primary proposal is that PG&E's RTP rate design utilizes a flat (or TOU differentiated) RNA.

K. Annual Marginal Cost Updates

In the years between GRC Phase II proposals and decisions, D.25-08-049 gives IOUs the opportunity to file a Tier 2 Advice Letter, no later than March 31 each calendar year, to update their marginal costs. IOUs have the option to update, either by using the MGCC values in the ACC, or by escalating the value using the process described in PG&E's AL 7243-E.[32]

At this point it is too early to tell how much additional value there is from annual marginal cost updates. If PG&E does wish to update its values in between GRCs then it will follow the guidance given in D.25-08-049.

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32 D.25-08-049, p. 142, COL 22.

L. Export Rate Design

As directed by D.25-08-049, PG&E's dynamic export rate will be equal to the sum of the following components:

- MEC, plus line losses;
- MGCC;
- MDCC; and
- MTCC (when available).

M. Customer Protection Design

1. Subscription Design

The subscription component of the RTP rate allows customers to "subscribe" to their typical load profile, which will be billed at the customer's OAT rates.[33] This means that only deviations from a customer's typical load profile will be charged or given credits at the dynamic hourly rate. This provides a hedging mechanism and customer protection against sustained periods of high dynamic prices.

In its CalFUSE White Paper,[34] Energy Division provided the following figure illustrating how this would work.

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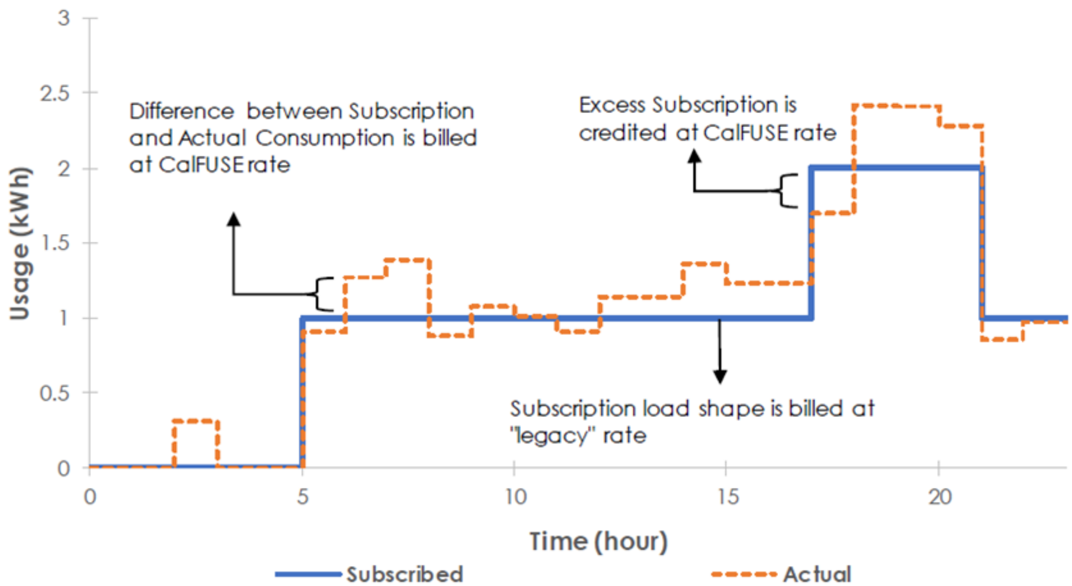
33 Rate elements like NBCs required to be billed on actual usage will be billed on the customer's usage during the billing period if that usage is different than the subscription amount. If subscription is based on the prior year's usage, or an average of the customer class, the customer's actual usage is most probably going to be different than the subscription amount.

34 CalFUSE White Paper, p. 67.

FIGURE 2-21
ENERGY DIVISION'S ILLUSTRATION OF THE SUBSCRIPTION IN ITS CalFUSE FRAMEWORK



The blue line represents the pre-purchased load shape, while the orange dashed line is the customer's actual usage. Only the area between these two lines is exposed to the dynamic price.

While only applying the dynamic price to a small fraction may seem like it reduces the impact of the dynamic offering, it does not reduce any incentive to shift load because any changes the customer makes are always at the margin and are always valued at the dynamic rate. A customer's decision to use one more or one less kWh will always be given the dynamic value; this is true no matter if the customer is currently above or below their current subscription level. Like the marginal RTP rate components, the subscription level will also be an hourly amount that can vary from hour to hour.

PG&E's proposal for subscription varies considerably from the method currently used in its pilots. This is because early guidance from Energy Division and the DF OIR Working Group was that prices for imports and exports had to be symmetric, which suggested a marginal-only rate, which suggested that subscription profiles needed to be very similar to actual profiles in order to accurately recover the non-marginal costs. Now that D.25-08-049 is mandating asymmetric pricing with an import rate that's revenue neutral to the retail rate, the accuracy and comparability of subscription profiles to actual usage is far less important. This gives both PG&E and customers more flexibility in designing much simpler subscription designs that meet the customers' needs to balance the risk/reward tradeoff in an RTP program.

One of the main changes to the subscription is that the subscription will now be an optional feature. Customers can choose not to have a subscription if they want more exposure to the dynamic rate or they do not want to deal with the extra complexity. Early feedback from PG&E's pilots suggests that customers find subscriptions very confusing, so having no subscription might make sense as a default option for some customer groups.

If a customer elects to have a subscription, the customer's subscription load profile will be made up of hourly net load levels for each day in the billing period. PG&E proposes the following definitions and options:

1) Determine the comparison profile.
   - If the customer has been on RTP rates for less than a year, the comparison profile is the customer's billing period from 12 months ago unless the customer does not have usage data from 12 months ago. In that case, the comparison profile will be a NEM or non-NEM rate schedule average load profile. PG&E is considering using the schedule average profile for all customers regardless of enrollment length, although this needs extensive analysis and requires customer performance data from the current pilots.
   - If the customer has been on RTP rates for more than a year, a comparison profile will be saved, made up of the 12 months of history before enrollment in RTP. If there are fewer than 12 months of history before enrollment, the earliest 12 months of usage will be used.
   - PG&E is considering updating the comparison profile periodically (for example, at least once every 4 years or potentially sooner if the customer's load has changed by a predetermined factor). Details will be decided after operational capabilities are assessed.
   - PG&E is also considering allowing the customer to request a refresh if their usage has changed.

2) Allow customers to (possibly) enroll in partial subscriptions.
   - PG&E is also considering allowing the customers to subscribe to a fraction (for example 50 percent) of their comparison profile.
3) Determine the subscription load for each hour.
   - If this hour occurs on a weekday/weekend, find the average net usage for this hour of the day from all weekdays/weekends in the comparison profile.

Since many NBCs have regulatory requirements to be billed based on actual usage, when calculating the shadow bill, PG&E will only use the subscription method for the dynamic components (generation, distribution, and eventually transmission). All other rate components will be billed based on actual usage.

This subscription design can be used no matter the combination of EPMC scaling and RNA, as long as the non-marginal costs are fully in the price signal. The subscription design is a complex method for customer protection, and no design will please all customers. Allowing an optional subscription may introduce the possibility for structural winners and losers with one option or the other being more attractive depending on load shape. Once more experience has been gained, PG&E will take customer feedback into consideration and may propose changes to the subscription design through an appropriate Advice Letter.

The table below summarizes how the elasticity model predicts that the average residential customer would fare using this subscription protection vs foregoing it. In addition to the Average Responsiveness and Optimistic Responsiveness scenarios, we also show data for No Responsiveness.

TABLE 2-2
EFFECT OF SUBSCRIPTION ON RESIDENTIAL CUSTOMER PERFORMANCE

Line No.		Subscription	No Responsiveness		Average Responsiveness		Optimistic Responsiveness	
			No	Yes	No	Yes	No	Yes
1	Before Load Shift	TOU Monthly Usage (kWh)	463	463	463	463	463	463
2		TOU Monthly Bill ($)	199	199	199	199	199	199
3		TOU Average Rate ($/kWh)	0.430	0.430	0.430	0.430	0.430	0.430
4	After Load Shift	Dynamic Monthly Usage (kWh)	463	463	465	465	470	470
5		Dynamic Monthly Bill ($)	199	202	198	201	197	201
6		Dynamic Average Rate ($/kWh)	0.430	0.437	0.426	0.433	0.419	0.427
7		Peak Reduction	0%	0%	7%	7%	20%	20%
8		System Savings ($)	0.00	0.00	2.37	2.37	7.05	7.05
9		Shifted Bill on TOU ($)	199	199	200	200	202	202
10		Customer Savings ($)	0.00	(3.40)	1.65	(1.75)	4.69	1.29
11		Contribution to Margin ($)	0.00	3.40	0.72	4.12	2.36	5.76

This table reveals interesting insights. In all cases, no matter the responsiveness, the average customer has a lower average bill without a subscription. In addition, it appears that a minimum level of responsiveness is required before a subscription becomes better than staying on the TOU rate. This is slightly contrary to the thinking that many of us have had while developing these rates over the last several years. Many of us had the intuition that if you have the subscription protection and do not modify your usage patterns, then you should have the same monthly bill because you will use about the same each hour as you did previously and the “overs” and “unders” should cancel out. However, this more detailed study reveals that this is not the case. The reality is that the overs and unders are the same size in terms of kWh, but the overs tend to happen during high dynamic prices and the unders happen when prices are low.

We also see that the subscription option does not impact peak reduction or system savings. This makes sense because, even with a subscription, the marginal rate is still the dynamic price—so that dynamic price is the only thing that should drive customer behavior.

PG&E accepts these results and will continue to offer subscription as an optional feature to its customers. Note that being on a subscription is not always a losing proposition; during hot years, a subscription will shield the customer from having all their energy exposed to the dynamic price and will result in a lower bill compared to not having a subscription. Though it does appear that a subscription will carry a naturally occurring "premium" during most years to enable it to offer the insurance-like protection it provides. This is acceptable to PG&E, but it will need to be part of the customer education process.

2. Bill Protection

The current HFP pilots that PG&E expects to run over the next several years all contain annual bill protection for all participating customers due to the nature of shadow billing.[35] However, PG&E believes that continual bill protection is not in the best interest of the system as there are cost-shift implications as well as the possibility of disincentivizing customers to respond to the price signal.

PG&E does not know precisely how long it will need to keep the shadow billing process whereby customers on RTP pay the lower of their OAT or RTP shadow bill on a 12-month cumulative basis, but it will likely be past 2027. Please see Chapter 4 for implementation details and the shadow billing process. Once PG&E has the capability to bill RTP for customers in its modernized billing system, PG&E proposes that bill protection only be provided to new residential customers and only for their first year on the rate. This is consistent with the bill protection recommendations that the settlement parties proposed in the 2020 GRC Phase II RTP proposal.[36]

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35 A "shadow bill" is calculated outside of PG&E's billing system based on the RTP rate and customers are provided a credit on their PG&E bill if the annual charges on the RTP rate are lower than a bill calculated based on the customer's OAT. If a customer's charges on the RTP rate are higher than on the OAT, the customer does not pay the additional charges. This provides a form of bill protection and reduces the risk of a customer participating on the pilot rate. See , Chapter 4.

36 A.19-11-019, Joint Motion for Adoption of Joint Settlement Agreement on RTP Issues Including Stage 1 Pilots, Appendix A, approved in D.22-08-002, p. 20.

3. Forward Transactive Option

In PG&E's pilots, agricultural customers will be able to view hourly price forecasts published seven days in advance and will have the opportunity to schedule their energy use and lock in these advance prices. Transactions for energy can be made from one to seven days before the usage date. This allows for prescheduling of energy use while locking in the published dynamic prices.

At this point there is not enough customer feedback to determine if a transactive option would be desirable to other customer classes. The HFP Pilots ordered in D.24-01-032 removed the transactive option from the approved implementation budget for non-agricultural customers, so it will only be initially available to agricultural at the start of the pilots. PG&E has not yet determined if it wishes to offer forward transactions to any other class, either for its pilots or after the pilots have concluded. The decision to include this feature will depend on its performance during the pilot as well as customer input. If these factors indicate that extending the forward transactive option to other classes is warranted, PG&E will file a Tier 2 Advice Letter seeking approval.

4. Low Income and Disadvantaged Communities

The Commission evaluated the reasonableness on whether the Large IOUs should be directed to modify the evaluations of the Expanded Demand Flexible (DF) Pilots to include understanding how low-income and Disadvantaged Community (DAC) customers could increase their enrollment, enhance their usage behavior, reduce bill impacts and experience bill savings from DF rate programs.[37]

Further, the Commission ordered that PG&E provide a plan in this RTP Supplemental Testimony on:

- How DF rates can be designed to be user-friendly;
- How to identify and address the needs of low-income and DAC customers that may have an interest in subscribing to DF rates; and

[37] D.25-08-049, p. 129.

- How to mitigate the impact of dynamic rates on low-income and DAC customers.[38]

PG&E will work with Energy Division staff to modify the evaluation of the HFP Pilots, as authorized in D.24-01-032, to specifically study how low-income and DAC customers can increase enrollment, enhance usage behavior, reduce bill impacts, and experience bill savings from DF rate programs. This evaluation will include residential customers in multi-unit dwellings and non-residential customers.

PG&E will submit a plan in its Q3 2027 Updated Supplemental RTP describing how DF rates can be designed to be user-friendly for low-income and DAC customers, which will include leveraging findings from the HFP Pilot evaluations to identify barriers and solutions for customer understanding and engagement.

In addition to the above, PG&E proposes leveraging the 2028 Low Income Needs Assessment (LINA) to inform future DF rate design and program improvements for low-income and DAC customers. Per Public Utilities Code Section 382(d), the CPUC is mandated to complete a LINA every three years in coordination with the Low Income Oversight Board (LIOB), and that the assessment:

> shall consider whether existing programs adequately address low-income electricity and gas customers' energy expenditures, hardship, language needs, and economic burdens.

Given the LINA is managed by income qualified program staff at the Energy Division with inputs from the LIOB, PG&E believes the stakeholder composition and expertise will provide the necessary inputs to anticipate and mitigate potential DF challenges faced by low income and DAC customers.

PG&E will request the scope of the upcoming 2028 LINA[39] to include research on the above provisions and examine how low-income households will be impacted by dynamic rates, their understanding of rate structures, and barriers to participation.

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[38] D.25-08-049, p. 145, COL 31.

[39] The 2028 LINA was funded by D.21-06-015 in the amount of $500,000. D.21-06-015, p. 393.

PG&E will file a Tier 1 Advice Letter within 90 days after the final evaluation reports from the HFP Pilots and the 2028 LINA study are issued, describing learnings and how they will be used to improve DF rate programs for low-income and DAC customers in future GRC Phase 2 applications.

N. Demand Charges With RTP

Demand charges are an essential part of cost-based ratemaking. They are the mechanism by which utilities can provide low-cost electricity to customers that use it efficiently—customers that have a high load factor. For equipment that is close to the customer, PG&E needs to size its capacities to manage the single highest load the customer puts on the equipment, even if that load is only for a few minutes. It does not matter what time of day this maximum load occurs; those capacity costs are driven by this single instance.

PG&E intends to continue to keep the maximum demand charge for RTP customers who take service on a rate schedule that includes a maximum demand. The revenues associated with the maximum demand are removed from the revenue neutral calculations for the dynamic rate, so there is no double counting of revenues. Energy rates will be lower for schedules with a maximum demand charge, as is appropriate.

There was some discussion in the Working Groups around how maximum demand charges make it difficult to optimize behavior because load shifting could create new, higher levels of demand. A typical proposed solution was to convert the demand charges to energy charges. PG&E does not support this method for several reasons.

First, this method treats all customers as if they have a schedule-average load factor. This will instantly harm customers with good load shapes (high load factors) and give a windfall to poor load shapes (low load factors). In the Agricultural Flexible Irrigation Technology (AgFIT) pilot, a price averaging method was used which converted demand charges into energy charges. The analysis of the AgFIT results showed that the savings that a customer experienced were heavily tied to their load factor.[40] The influence of load factor was so strong that it overwhelmed any savings due to dynamic price

[40] Hansen, D. and Clark, M., Christensen Associates, Final Evaluation of VCE's Agricultural Pumping Dynamic Rate Pilot (Apr. 17, 2025), pp. 3, 70-76.

responsiveness. Customers with low load factors saw instant savings with no behavior changes while customers with high load factors could not achieve any savings, even with a strong response. This is unacceptable in PG&E's opinion.

Second, while demand charges do make it more difficult to program automation tools to help manage load, it is still possible. Simple statistical models or more advanced machine learning algorithms could be used to calculate the probability of creating a new max load level at various times throughout the billing period. By adding this factor, one can create a system that models total expected prices and advises accordingly. While at first glance it seems that a maximum demand rate could create conflicting incentives for times when the dynamic rate is low, it is the combination of these factors that reflect the true cost to the grid. Just like when a high distribution rate may send conflicting incentives with a low generation rate, it is the total combination of all prices that reflects the correct price signal.[41]

Without a subscription, it is fairly easy to design a dynamic rate with a demand charge that collects the appropriate revenues with the appropriate mechanisms. Customer charges and maximum demand charges stay as they are on the OAT. Peak and part-peak demand charges are replaced with the hourly price signals in the dynamic rate, keeping cost-causation. Energy charges are also folded into the dynamic rate. So one wants to keep maximum demand charges, but drop peak demand because keeping peak demand would double-count those revenues.

When a subscription is added, all parts of the OAT structure need to be maintained for demand costs. That is because with a subscription the dynamic rate only covers the deviations from the subscription load level and is likely to be close to zero when netted out. With no additional net revenues from the dynamic energy, it becomes clear that all expected revenues must be collected through OAT demand charges, including peak and part-peak demands.

With these two endpoints firmly established, it creates an odd situation if PG&E were to offer the option of a partial (say 50 percent) subscription profile. In this case only half of the revenues that are normally collected by peak demand charges would be collected in the dynamic rate. That would imply that

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41 Assuming prices are correctly cost based.

the 50 percent subscription should charge for *half* of the peak demand at the OAT rate.[42]

PG&E presents in Table 2-3, below, how dynamic rates might look for an average B-20 Secondary customer using its proposed design, average responsiveness, and various levels of subscription coverage.

TABLE 2-3
EFFECT OF SUBSCRIPTION ON B-20 SECONDARY CUSTOMER PERFORMANCE

Line No.		Subscription	0%	50%	100%
1	Before Load Shift	TOU Monthly Usage (kWh)	515,128	515,128	515,128
2		TOU Maximum Demand (kW)	1,216	1,216	1,216
3		TOU Peak Demand (kW)	1,144	1,144	1,144
4		TOU Monthly Bill ($)	144,003	144,003	144,003
5		TOU Average Rate ($/kWh)	0.280	0.280	0.280
6	After Load Shift	Dynamic Monthly Usage (kWh)	518,020	518,020	518,020
7		TOU Maximum Demand (kW)[(a)]	1,216	1,216	1,216
8		TOU Peak Demand (kW)	–	572	1,144
9		Dynamic Monthly Bill ($)	143,380	143,842	144,304
10		Dynamic Average Rate ($/kWh)	0.277	0.278	0.279
11		Peak Reduction	6%	6%	6%
12		System Savings ($)	1,779	1,779	1,779
13		Shifted Bill on TOU ($)	144,765	144,765	144,765
14		Customer Savings ($)	1,385	923	461
15		Contribution to Margin ($)	395	856	1,318

(a) Maximum and peak demands assumed to not change with price response for simplicity.

For now, PG&E proposes to use this method of charging maximum demand charge no matter the subscription level, but to vary the peak and part-peak demand charges by subscription percentage. PG&E will continue to develop and refine this concept, perform customer outreach, and see how well it fares with potential customers.

42 The maximum demand charge would still be at full demand, even with a 50 percent subscription because both the no subscription and 100 percent subscription cases charge a full maximum demand.

O. Other Rate Design Topics

1. RTP for NEM Customers

The guidance in D.25-08-049 is completely silent regarding NEM customers. Because of this silence, it appears that D.25-08-049 requirements would give marginal-only compensation for all exports, NEM or non-NEM. This might work when these customers have a subscription that would offer retail compensation at expected export levels and make marginal-only adjustments to that total. However, this would not give parity when the customer elects not to have a subscription as it would now devalue a larger part of their export compensation.

For this reason, PG&E proposes to offer NEM/NBT customers OAT compensation for any exports that would otherwise receive OAT credits, then the HFP export price for anything in excess.

2. Potential Issues That Will Need Investigation

During the course of running the HFP Pilots, thus far, PG&E has noted several items that could potentially be improved. In addition, the new requirements from D.25-08-049 and the analysis requested have required rate design proposals that were put together under extreme time pressure. These proposals were the best PG&E could develop within the required 60-day deadline, but would benefit from further study, analysis, and concrete data from the HFP Pilots. Exhibit (PG&E-5), Chapter 4 discusses the need for a Q3 2027 Updated Supplemental RTP Testimony to address such real-world learnings from actual PG&E RTP customers.

PG&E presents these items that need further development as well as existing concerns that PG&E has highlighted in past filings. Many of these items have been discussed in prior sections as noted.

a. Refinements to MEC Losses

As discussed in Section E.

b. Alternative Distribution Rate Designs That Incorporate Actual Capacity Constraints

As discussed in Section H.7.

c. Long-Term Solutions for Changing Circuit Configurations

As discussed in Section H.9.

d. Alternative Distribution Aggregations

Changing circuit conditions have a greater effect on dynamic rates developed at the circuit level compared to rates developed at a higher aggregate level like a substation or other geographic area. Not only will a switch cause a higher percentage of load to change, but smaller aggregations of load will have higher forecast error and are more likely to drift from their calibrated historical behavior. For these reasons, PG&E is investigating developing distribution rates at different levels of aggregation, but this will take substantial analysis and time. An ideal solution would: (1) allow customers to know which prices apply to them without a lookup table, (2) have prices that are tied to customers' actual grid conditions, and (3) cause load modifications to directly correlate to value for the grid.

e. Improvements to Non-Marginal Cost Rate Design

As discussed in Section J.

f. Improvements to Subscription Design

As discussed in Section M.1 and Section N.

g. Potential For Double Payment

In PG&E's previous RTP proceedings, there have been concerns around the timing of revenue collection between RTP and standard TOU customers and potential over- or under-collections. In those proceedings it was hypothesized that if there is a summer heat wave with high energy prices and high load on the circuits, RTP customers will pay higher rates immediately, as is appropriate. TOU customers will not pay these higher utility costs immediately, but they will pay them the following year when the revenue under-collection from the heat wave flows into balancing accounts through the established annual process. The potential concern was that in the following year, the increased rates for standard TOU customers will also increase the subscription rate for RTP customers, essentially making them pay for the heat wave a second time. The opposite situation happens if RTP prices are lower than average.

Under PG&E's existing pilots, we believe that the potential for this occurrence has been mitigated with the addition of subscriptions. With subscriptions, when prices are high, there is no guarantee that RTP customers will pay more because the subscription design will allow customers to gain a large credit if they can reduce usage below their subscription quantity. Only usage above the subscription quantity would be charged the high price. In prior RTP configurations without a subscription, customers were always purchasing energy at RTP prices, so higher prices always meant higher bills. That is no longer the case with subscription.

The guidance in D.25-08-049 now makes subscriptions optional, so this potential issue has returned, but would only be applicable to some customers, making the matter even more complex.

In the prior GRC Phase II RTP settlement, PG&E agreed to monitor and measure potential over-/under-collections, but did not recommend any mitigation initially.[43] PG&E maintains the same philosophy for these rates and would evaluate over-/under-collections as part of its normal Measurement and Evaluation studies.

P. Eligibility

PG&E's existing pilots are open to many rate schedules in each customer class, with each pilot specifying its own eligible schedules. After the conclusion of the pilots, PG&E intends to continue to offer RTP to all schedules that were eligible under one of the pilots. In addition, PG&E proposes to remove the technology requirements from Schedule E-ELEC for customers that enroll in RTP, which would allow any residential customer to join RTP thus enabling PG&E to meet LMS requirements.

This expanded eligibility definition means that all metered customers (except for Streetlighting) will have a schedule that they are able to switch to and elect to enroll in RTP.

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43 A.19-11-019, Joint Motion for Adoption of Joint Settlement Agreement on RTP Issues Including Stage 1 Pilots, Appendix A, approved in D.22-08-002, pp. 28-29.

Q. Conclusion

PG&E is presenting these rate designs to comply with D.25-08-049's requirement to submit rate design testimony within 60 days. These rate designs represent PG&E's best effort based on available information.

This chapter presents PG&E's proposal for RTP rates after the HFP pilots and Phase II VGI Pilots have concluded; however, please see Chapter 4 for PG&E's proposal to provide Q3 2027 Updated Supplemental RTP Testimony once we have the guidance decision in Enhanced Demand Response Order Instituting Rulemaking (OIR) on real-time rates, as well as the results of the real-time pilots. PG&E discusses its RTP Regulatory Roadmap, which includes a proposed schedule for this update and PG&E's Stop-Gap Interim RTP Pilot Proposal to extend the HFP pilots and Phase II VGI Pilots discussed, in Chapter 4.

PG&E is recommending that the Commission hold off ruling on this proposal until any proposed changes are incorporated from the supplemental filings that PG&E discusses in Chapter 4. If the Commission decides to adopt rate design elements prior to the those requested filings, PG&E recommends that additional flexibility be built into the Decision allowing PG&E to modify rate design components (for example, coefficients, subscription characteristics, distribution topography) via Tier 2 Advice Letter as needed when new learnings are discovered, without needing to wait for an additional GRC rate design cycle.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

MARGINAL GENERATION CAPACITY COST PRICING FORMULA FOR PG&E'S DAY-AHEAD HOURLY REAL TIME PRICING (DAHRTP) RATES, REPORT TO PARTIES IN CALIFORNIA PUBLIC UTILITIES COMMISSION DOCKETS A.20-10-011 AND A.19-11-019

Application: A.19-11-019
Exhibit No.: PG&E-RTP-7
Date: March 17, 2022
Corrected: March 16, 2022
Witnesses: Jan Grygier
Ben Guiterrez
Ryan Mann
John D. Wilson
Catherine E. Yap

PACIFIC GAS AND ELECTRIC COMPANY

COMMERCIAL ELECTRIC VEHICLE DYNAMIC RATE OPTION

MARGINAL GENERATION CAPACITY COST PRICING FORMULA FOR PG&E'S DAY-AHEAD HOURLY REAL TIME PRICING (DAHRTP) RATES, REPORT TO PARTIES IN CALIFORNIA PUBLIC UTILITY COMMISSION DOCKETS A.20-10-011 AND A.19-11-019

MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates

REPORT TO PARTIES IN CALIFORNIA PUBLIC UTILITY COMMISSION DOCKETS A.20-10-011 AND A.19-11-019

March 15, 2022

MGCC Study Participants:

- Jan Grygier and Louay Mardini, Pacific Gas and Electric Company (PG&E)
- John D. Wilson and Paul Chernick, Resource Insight, Inc. for the Small Business Utility Advocates (SBUA)
- Ben Gutierrez and Vanessa Martinez, CPUC Public Advocates Office
- Catherine Yap, Barkovich and Yap, Inc., for the California Large Energy Consumers Association (CLECA)
- Ryan Mann, Enel X for the Joint Advanced Rate Parties (JARP)

1 Executive Summary

Two ongoing proceedings of the California Public Utilities Commission (CPUC or Commission), Application (A.)20-10-011, Commercial Electric Vehicle (CEV) rates, and A.19-11-019, Pacific Gas and Electric Company's (PG&E) General Rate Case (GRC) Phase II, are developing rate schedules with a day-ahead, hourly real-time pricing (DAHRTP) rate component. As a result of a stipulation and related rulings in these two proceedings, several parties to those proceedings conducted this Marginal Generation Capacity Cost (MGCC) Study to research the design of a pricing formula to allocate PG&E's MGCC on an hourly basis. The hourly MGCC pricing formula is designed for use in a DAHRTP rate. The MGCC Study Participants recommend a formula that calculates much of the DAHRTP price from the value of net load, adjusted for temperatures affecting imported energy from areas outside the management of the California Independent System Operator (CAISO) (referred to as "ANL_T"). The remainder of the MGCC price component would be captured by a Flex Alert event "adder." It is appropriate to use a combination of ANL_T and Flex Alert events to determine hourly MGCC pricing because grid stress and reliability events may occur in a variety of load conditions.

High load or net load (load adjusted for wind and solar) days have a high probability of the CAISO issuing an Alerts, Warnings, and Emergencies (AWE) notification (AWE event), but not a 100 % probability. Other factors affect system reliability, and grid stress and reliability events do occur on days with low load or net load. For these reasons, the MGCC Study Participants evaluated alternative adjustments to net load, determining that:

- Consideration of temperatures in Arizona and the Pacific Northwest improved the precision of predicting the probability of the CAISO calling an AWE event; and
- A Flex Alert event "adder" of $0.25/kilowatt-hour (kWh) also contributes to the MGCC pricing because other factors beyond ANL_T can create stress in the grid and influence CAISO decisions to call an AWE event; this "adder" also leverages extensive publicity around Flex Alerts.

The ANL_T portion of the MGCC pricing formula is designed to collect the majority of the MGCC cost by using a sigmoidal (S-shaped) to relate this adjusted net load metric to an hourly price function. The hourly price function is referred to as PCAF-S to distinguish it from PG&E's original proposed Peak Capacity Allocation Factor (PCAF)-based function.[1]

In choosing a recommended MGCC pricing formula, the MGCC Study Participants considered both the accuracy of the signal (in terms of aligning with CAISO AWEs, which indicate operationally times of high grid stress), as well as the year-to-year variability expected under various versions of the MGCC signal. Some of the benefits of the recommended MGCC pricing formula, compared to PG&E's original proposal, are:

- Non-zero MGCC prices at lower adjusted net loads;

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1 The standard PCAF formula allocates capacity to hours in which a measure of load is above a threshold (here, 80% of the expected maximum annual hourly load), proportional to the amount the load exceeds that threshold.

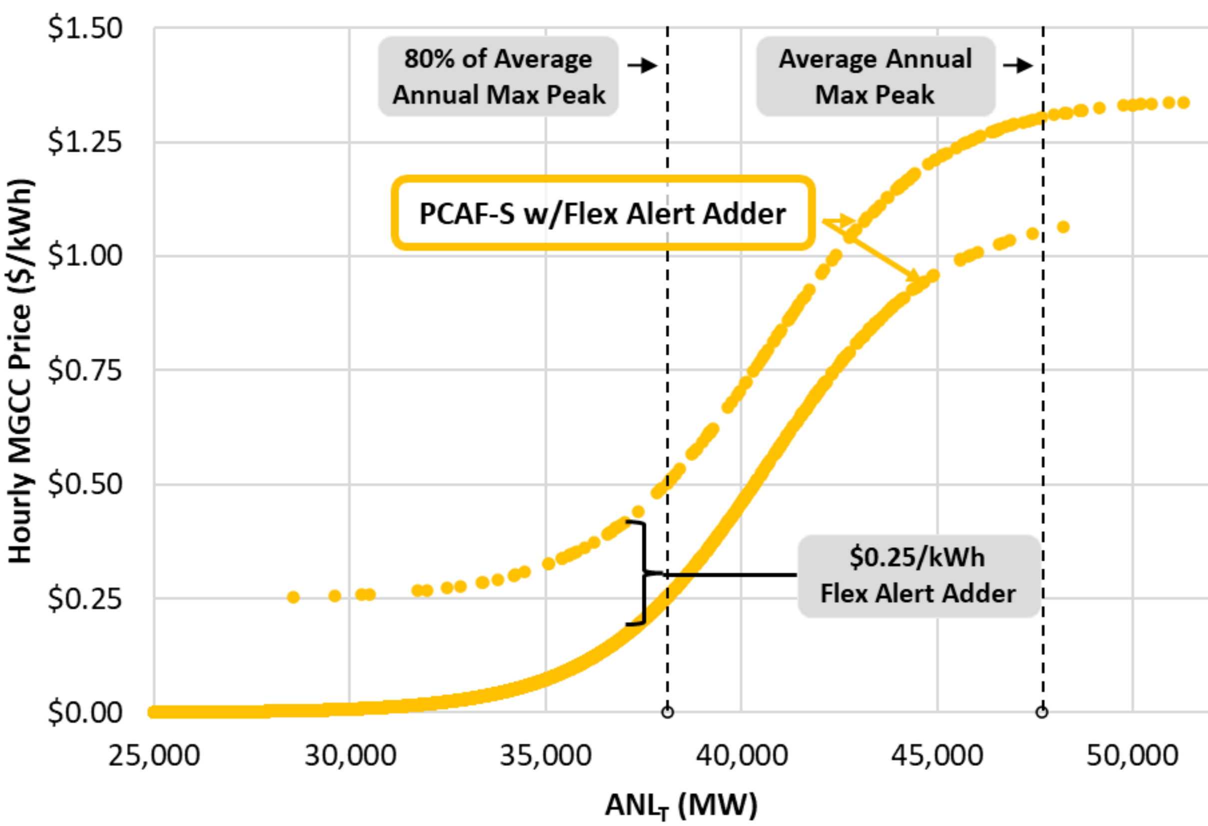
- A maximum hourly MGCC price component (rather than increasing indefinitely at higher and higher net loads); and
- Lower year-to-year revenue variability.

Low year-to-year variability in the MGCC portion of the DAHRTP rate is important because it reduces the likely magnitude of revenue over- and under-collections.

The MGCC Study Participants also evaluated potential bill impacts on a prototypical Schedule B-6 customer. The DARHTP 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.

Accordingly, the MGCC Study Participants recommend the CPUC adopt the following formula for setting the MGCC price in PG&E's DAHRTP rate., illustrated in Figure 1 and defined in Equation 1. 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 MGCC of $90.35/kilowatt-year (kW-year) in an average year, and the variables A and B are determined using logistic regression using historical data, as explained in Section 3.

Figure 1: Hourly MGCC Pricing Formula
Applied to Net Load and CAISO Day-Ahead (DA) Energy Prices for 2017-2021



Equation 1: Hourly MGCC Pricing Formula

Hourly MGCC Price: $PCAF\text{-}S(ANL_T) = H / (1 + \exp(A - B^{*} ANL_T)) + E * \text{Flex Alert}$

$PCAF\text{-}S(ANL_T < L) = 0$

ANL_T is normalized[2]

E = $0.25

H = $1.097

A = 18.78

B = 23.72

L = 27,713 MW

The MGCC Study Participants anticipate 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 MGCC price of $90.35/kW-year, using the methods described in this report. The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

The MGCC Study Participants are authorized to state that PG&E, Small Business Utility Advocates (SBUA), Public Advocates Office at the California Public Utilities Commission (Cal Advocates), California Large Energy Consumers Association (CLECA), and Joint Advanced Rate Parties (JARP) support the report and its recommendations, and urge the Commission accept the findings and recommendations of the MGCC Study. It is also hoped that other parties to A.20-10-011 (CEV rates), and A.19-11-019 (PG&E's GRC Phase II) will provide their support.

2 ANL_T is normalized using the formula: $(ANL_T – Min)/(Max – Min)$, where Min/Max are the minimum/maximum ANL_T values in the dataset. The normalized values of ANL_T used in Equation 1 range from 0 to 1.

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2.3 Equations

3 PROCEDURAL HISTORY

PG&E proposed to develop dynamic rates based on DAHRTP signals in two CPUC proceedings: A.20-10-011, CEV rates, and A.19-11-019, its GRC Phase II. The CEV proceeding went to hearing in June 2021 on numerous issues raised by PG&E's application. CPUC Decision (D.) 21-11-017 (November 18, 2021) in the CEV proceeding resolved most issues, but the issue of the appropriate allocation of MGCC to each hour was subject to a stipulation between parties that agreed to form an MGCC Study Working Group to collaboratively study the complex issues in greater depth (the MGCC Stipulation).[3]

In D. 21-11-017, the CPUC continued the CEV proceeding to provide time for completion of this MGCC Study, and Administrative Law Judge (ALJ) Sisto extended that time to March 15, 2022 by a January 14, 2022 ruling. At the January 26, 2022 Real-Time Pricing (RTP) hearings in the GRC Phase II proceeding (A.19-11-019), ALJ Sisto confirmed her direction that PG&E file and serve the same MGCC Study as a late-filed exhibit, and that any party from PG&E's GRC Phase II proceeding who is interested in commenting this study should do so through the proceedings scheduled in A.20-10-011, for administrative efficiency. This MGCC Study Report fulfills the requirements of D.21-11-017 and subsequent related rulings.

Most of the issues in PG&E's 2020 GRC Phase II were decided in D.21-11-016, but RTP rate design issues, including the issue of the appropriate allocation of the MGCC to each hour, were deferred to a separate track. On January 14, 2022, a settlement of most RTP issues was filed in A.19-11-019 (January 14 Settlement).[4] The parties are awaiting a Proposed Decision (PD) on the January 14 Settlement.

In addition, D.21-11-016 reserved the issue of a whether Property Tax Adder should be applied to the annual MGCC proposed by PG&E for a future decision. On January 21, 2022 PG&E and CLECA filed a stipulation regarding the property tax adder, and after no protests were filed on the stipulation, a PD accepting the stipulation was issued on February 11, 2022.[5] The earliest a Final Decision on the Property Tax Adder PD can be voted on by the Commission is March 17, 2022.

This document assumes that the annual MGCC of $76.35/kW-year specified in that PD will be maintained in the CPUC's Final Decision. The annual MGCC is increased by the 15% Planning Reserve Margin (PRM) and losses of 2.9% corresponding to primary voltage distribution service to yield a final expected annual capacity cost for primary voltage customers of $90.35/kW-year.

The methodology issues concerning development of the MGCC element for the hourly RTP rate are in both the GRC Phase II RTP proceeding A.19-11-019 and the CEV proceeding, A.20-10-011. In both proceedings, the MGCC RTP issues were deferred to a future phase of the proceeding. The MGCC RTP

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[3] A.20-10-011, Exhibit PG&E-20, Joint Stipulation on Study for MGCC Rate Design Issue (MGCC Stipulation).

[4] A.19-11-019 Joint Motion of the Agricultural Energy Consumers Association, CLECA, California Solar and Storage Association, Enel X North America, Inc., Energy Producers and Users Coalition, Federal Executive Agencies, OhmConnect, Inc., Cal Advocates, SBUA and PG&E (U 39 E), For Adoption of Joint Settlement Agreement on RTP Issues Including Stage 1 Pilots (Jan. 14, 2022).

[5] A.19-11-019, PD (Feb. 11, 2022).

rate issue is now set for hearings for May 18 to 20, 2022, in A.20-10-011.[6] This document is the MGCC Study described in Exhibit 20 of A.20-10-011, and required to be served by March 15, 2022, pursuant to the ALJ ruling issued January 14, 2022 in A.20-10-011.

Parties generally agreed that PG&E should offer a consistent DAHRTP rate design for both the CEV pilot participants and whatever eligible customer groups are offered an RTP rate as a result of a GRC Phase II decision. One additional party to the Phase II proceeding joined the parties to the CEV proceeding in the MGCC Study Working Group.

The MGCC Study Working Group includes five organizations represented by subject matter experts who have collaborated in the study on behalf of their respective organizations.

- PG&E – Jan Grygier, Louay Mardini and Matt Kawatani
- SBUA – John D. Wilson and Paul Chernick (Resource Insight, Inc.)
- Cal Advocates – Benjamin Gutierrez and Vanessa Martinez
- CLECA – Catherine Yap (Barkovich & Yap, Inc.)
- JARP – Ryan Mann (Enel X)

A number of other individuals from the five organizations also contributed substantially to the MGCC Study Working Group's work product. Throughout the text, the term "MGCC Study Participants" is meant to refer to a consensus interpretation, opinion or agreement reached among the individual representatives of each organization.

3.1 Proposals Set Forth in Testimony Regarding the Allocation of MGCC to Hours

The MGCC Study Working Group parties set forward positions in several rounds of testimony filed in both the CEV and GRC Phase II proceedings. These positions evolved in response to parties' mutual consideration of proposals and further research. A brief summary of the rate design approaches filed by four parties[7] follows.

3.1.1 PG&E

PG&E proposed to use its generation PCAF method based on Adjusted Net Load (ANL)[8] to determine the appropriate allocation of capacity cost to the DAHRTP prices for each hour of the year. PG&E's ANL/PCAF method includes a hydro variable in the definition of ANL and uses all weather year

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6 The January 14 settlement in A.19-11-019, pp. 15-18, refers to the MGCC Stipulation (A.20-10-011, Exhibit 20) regarding the scope, approach, and schedule for a MGCC study to determine the structure for the Stage 1 RTP pilot rates' MGCC component. The January 14 settlement proposes that the litigation for the MGCC RTP rate component occur on a consolidated basis in the two proceedings.

7 CLECA did not address the allocation of MGCC in testimony.

8 ANL is equal to Net Load (gross load (GL) minus grid-scale wind and solar generation) minus hydro, nuclear, and other renewables. ANL is thus the amount of load that must be met by thermal generation, imports, energy storage, and nuclear.

scenarios in the calculation of the threshold and the "PCAF denominator."[9] PG&E initially proposed to multiply the hydro variable by a factor greater than one (as used in PG&E's Marginal Energy Cost (MEC) model from the GRC Phase II), but later suggested using a lower factor to take into account the fact that hydro generation typically shows lower variability year-to-year during grid stress conditions than during normal operations.

3.1.2 Cal Advocates

Cal Advocates proposed to reflect different hydro year assumptions than used by PG&E, by limiting the selection of weather years used to calculate both the PCAF threshold and the PCAF denominator in the MGCC allocation to those simulated weather years with similar hydro conditions to the current year. Cal Advocates also proposed allocating 13% of the MGCC to hours that reflect the CAISO issuance of a DA Flex Alert or DA Alert[10] with the remaining MGCC value (87% of total) assigned to hours based on PG&E's proposed PCAF methodology.

3.1.3 Small Business Utility Advocates

SBUA proposed to allocate the MGCC based on a combination of CAISO Alerts and Flex Alerts, CAISO Restricted Maintenance Operations (RMO) events, and an ANL/PCAF method based on PG&E's hydro assumptions or with Cal Advocates' hydro year modification, potentially using a different functional form for PCAF weighting above the threshold than PG&E's linear function, and/or using a different threshold than PG&E's 80% of scenario-averaged maximum annual ANL.

3.1.4 JARP (California Solar and Storage Association, Enel X)

JARP did not oppose PG&E's proposed MGCC allocation methodology but also supported a collaboration among parties to address allocation issues arising in the proceeding.

3.2 Scope of MGCC Working Group Study

The MGCC Stipulation established the scope of the Working Group study as:

> *[to] determine the fit between alternative formulations of hourly MGCC... and capacity shortfall (reliability) metrics. The primary purpose of a real-time capacity price signal is to accurately reflect temporal (hourly) variations to the risk that there will be insufficient capacity to serve demand – and thus variations in the capacity costs at the margin of serving incremental load.*[11]

In order to develop the formulations of hourly MGCC and capacity shortfall metrics, the MGCC study will

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9 The "PCAF denominator" is equal to the expected sum of load above the threshold over a set of "weather years" for which load and renewable generation is matched to the weather in that calendar year.

10 Cal Advocates proposed to assign 13% of the MGCC to the hours during which CAISO issues a day-ahead Flex Alert or alert (CAISO alert) and only for the hours between 3-9pm for which PG&E's PCAF-based capacity prices do not meet or exceed a certain threshold, possibly with limits on the minimum and maximum number of hours called in each calendar year.

11 MGCC Stipulation, p. 5.

analyze the relationship of the following variables to the condition of the CAISO grid: 1) hydro year conditions, 2) the definition and weighting of the hydro variable in the calculation of Adjusted Net Load (ANL), 3) CAISO restricted maintenance operations (RMO), 4) day-ahead CAISO Flex Alerts and CAISO alerts events, 5) other CAISO warning and emergency events, 6) the Peak Capacity Allocation Factor (PCAF) threshold [that identifies PCAF hours], and 7) the functional form of PCAF weighting above the PCAF threshold.[12]

And finally, the MGCC Study will

help to identify the appropriate level of inter-annual variation in the DAHRTP pilot rate's MGCC price element. Parties' MGCC proposals result in differing levels of intra- and inter-annual variation in capacity prices. By comparing the various proposals to reliability metrics and determining which proposals produce the best fit, the Study could indicate what level of intra- and inter-annual variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years.[13]

While the MGCC Study is mainly focused on the hourly MGCC price component, the MGCC Study also considers interactions with the other two components of the DAHRTP price, the MEC and the Revenue Neutral Adder (RNA). The MGCC Study Participants did not evaluate any alternatives to the MEC and RNA components, which have been resolved by D.21-11-017 (November 18, 2021) in the DAHRTP-CEV proceeding. The MGCC Study Participants assumed for purposes of this study that those issues would be resolved similarly in the GRC Phase II proceeding.

12 MGCC Stipulation, pp. 1-2.

13 MGCC Stipulation, pp. 5-6.

4 DATA SOURCES

Ideally, the design of the hourly MGCC price component would rely primarily on modeled forecast data to be best aligned with the expected mix of resources that underlie those generation costs. Forecast data also provide useful estimates of low-probability, high salience reliability events. However, forecast data do not incorporate information from CAISO AWEs, which provide a direct indication of hours in which the CAISO determines that there is stress on the grid, i.e., an elevated risk of outages.

Fortunately, the incidence of rolling blackouts is normally very low, as evidenced by the only three Stage 3 Emergencies that occurred between 1998 and 2021.[14] Modeled forecast data does not include a direct measure of rolling blackouts, but instead provides a statistical measure of Expected Unserved Energy (EUE), which measures the expected loss (or curtailment) of load in units of megawatt-hours (MWh). The difference between historical and modeled forecast reliability measures demonstrates both the necessity and challenge of using both types of data in this study.

From a historical perspective, the MGCC Study Participants recognize that the CAISO issues other notices prior to the occurrence of a Stage 3 Emergency that are available for indicating increasing levels of grid stress. Based on analysis, the Study Participants have hypothesized that RMOs indicate moderate risk of bad outcomes, Alerts and Flex Alerts represent elevated risk, while CAISO Warnings and Stage Events represent greatly increased risk ultimately resulting in actual load drop on the system, as discussed in Section 4.1.3 below.

A similar pattern of increasing levels of grid stress is also available in modeled forecast data. EUE is the primary measure of capacity shortfall and is assumed to be linear; in other words, an EUE of 100 MWh in an hour (or year) is assumed to be ten times as costly to customers and the California grid as an EUE of 10 MWh. Other measures of grid stress are non-spin reserve shortfall, upward reserve shortfall, and calls on demand response (DR) resources. While there is not a one-to-one relationship between historical and modeled forecast reliability metrics, the MGCC Study Participants concluded that the statistical similarities could be leveraged to develop a useful model of grid stress.

However, as discussed below, the MGCC Study Participants determined that the available forecast data were generally not suitable for use in a rate design context. While suitable modeling is likely feasible, the MGCC Study did not have access to model data that would allow for modeled forecast reliability metrics to be described in a manner that could be used directly to design a DAHRTP rate. Some of the available forecast data were used as benchmarks, or comparator data, for example to indicate the general level of year-to-year variability expected for capacity-related costs.

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14 A Stage 3 Emergency is the highest risk event in the CAISO's AWE system and indicates that load interruptions (blackouts) are necessary. There were 38 Stage 3 Emergencies in 2001, the "California Energy Crisis" year. These emergencies were at least partially due to manipulation by market entities that has since been rendered significantly less likely.

4.1 Historical Data

4.1.1 Extended MEC Data

As part of its marginal cost showing in its Phase 2 proceeding, A.19-11-019, PG&E had prepared a set of data incorporating hourly load, generation and price information for January 2012-December 2019. This dataset was extended to the period May 2010-December 2021 and simplified to remove the MEC model calculations to reduce file size and the proprietary portions of the dataset. The extended data set incorporates historical hourly day ahead (DA) prices, real-time (RT) prices, CAISO total load, CAISO net load, adjusted net load, temperature data for surrounding areas, quantity of load met by various resource types, and other pertinent information. The MGCC Study Participants used this historical data in most historical analyses.

4.1.2 Alternative Load Metrics

The MGCC Study Participants analyzed six different load metric candidates for use in the DAHRTP design. Because most energy and capacity is procured to meet CAISO system-wide requirements, rather than local PG&E resource needs, all six candidates are based on total CAISO system load.

1. **Gross Load (GL)** – Excludes behind-the-meter (BTM) generation
2. **Net Load (NL)** – Also excludes interconnected solar and wind generation
3. **Resource-Adjusted Net Load (ANL_R)** – NL adjusted to exclude other Greenhouse Gas (GHG)-free resources, including hydroelectric, nuclear, biomass/biomass and geothermal
4. **Temperature-Adjusted Net Load (ANL_T)** – NL adjusted to account for non-CAISO system conditions, such as imports availability, using weather stations at Phoenix Airport (PHX) and Seattle-Tacoma Airport (SEA)[15]
5. **ANL_{RT}** – Combines the adjustments for NL, ANL_R and ANL_T into a single metric
6. **ANL_{RTG}** – Combines GL, ANL_R and ANL_T into a single weighted average metric

Note that in the remainder of this document, the term "net load" (without capitalization) refers to load metric candidates 2 through 6 generically, not just to candidate 2, above.

4.1.3 Alerts, Warnings, and Emergencies Data

The MGCC stipulation approved in D.21-11-017 (November 18, 2021) noted, "It would also be valuable to the Study to obtain more detailed information from CAISO regarding the standards that it applies to initiate an Alert, Warning or Emergency (AWE) event, both in general and with respect to historical events." MGCC Study Participants requested this information during a conference call on July 13, 2021, but the CAISO declined to provide information beyond what is published on its website.[16]

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15 The same temperature adjustments were used in the MEC model developed by PG&E in its 2020 GRC II testimony, A.19-11-019, Exhibit PG&E-2, Ch. 2, pp. 2-29 to 2-31, Marginal Generation Costs.

16 Overall procedures for calling AWEs are listed in Operating Procedure 4420, available at http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx. However, that document does not detail specific conditions that can trigger an AWE. A list of AWEs since 1998 is at http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf.

The MGCC Study Participants built on data assembled by Cal Advocates and SBUA for their testimonies, and created a complete list of each AWE event, the time it was called, and the dates and hours that it was in effect. AWEs designated by CAISO as restricted to Southern California were discarded. Most of those designations occurred as a result of the restrictions on the availability of the Aliso Canyon gas storage facility while natural gas supplies remained plentiful on PG&E's system.

The MGCC Study Participants used historical AWE event data as a means of determining the extent to which the six candidate load metrics correlate with system stress or capacity inadequacy. AWE event data published by the CAISO turned out to be incomplete (e.g., missing the time of the announcement) or inconsistent with press releases, social media announcements, or other information published by the CAISO. The MGCC Study Participants have used multiple information sources to check the data in the AWE list and ensure its accuracy. Overall, relatively few AWE events have been called by the CAISO over the past decade, with some years having very few events called, as shown in Table 1.[17]

The various AWE event types are described in CAISO Operating Procedure 4420, as summarized below.

- **Flex Alert** – Flex Alerts are part of a consumer educational and alert program for voluntary conservation of electricity during heat waves and other challenging grid conditions. Flex Alerts are most effective when issued a day or more in advance of "operating day," but may be issued with little or no advance notifications during sudden grid emergencies.
- **Restricted Maintenance Operations (RMO) notice** – RMO notices are issued when CAISO determines it is necessary to cancel or postpone any/or all work to preserve overall System Reliability. Operators are notified to only approve outages of transmission and/or generation facilities that will have no potential negative effect on system reliability, and to utilize exceptional and manual intertie dispatch as necessary. RMO notices are typically issued for an extended duration, which includes some hours with low DA energy prices. CAISO Operating Procedure 4420B describes the procedure for determining RMO event durations, but the detailed description of that procedure is not publicly available. RMOs can be issued one or more days ahead or on the operating day.
- **Alert** – An Alert is a type of Energy Emergency that is a precursor to Stage 1 emergencies, as well as a trigger to inform utilities to consider activating Emergency Load Reduction Programs (ELRP). The MGCC Study Participants found that when an Alert was issued, the CAISO almost always issued a Flex Alert. For this reason, the MGCC Study Participants have analyzed these two AWE events in combination, abbreviating references to them as Flex Alerts and Alerts (FA/A) Events. Going forward, CAISO has specified that Alerts will always be issued by 3 p.m. on the day before the operating day.
- **Warning** – The CAISO declares a Warning event when its real-time analysis forecasts that one or more hours may be energy deficient with all available resources in use or forecasted

[17] The CAISO list of AWEs extends back to 1998 when the CAISO was formed. AWEs prior to 2010 were not considered in this study for two reasons: 1) the hourly load and generation data needed to construct the alternative load metrics discussed above are not available prior to April, 2010, and 2) the market prior to 2010 had a different structure (with a Power Exchange running a day-ahead market, and bilateral hour-ahead markets). Furthermore, the 2001 Energy Crisis resulted in a large number of AWEs due to factors such as market manipulation that are unlikely to be repeated and would be impossible to model.

to be in use and the CAISO is concerned about sustaining its required Contingency Reserves. A Warning event may trigger decisions to dispatch DR and non-market generation capacity resources. Going forward, Warnings and Emergencies (W/E) will always be called on the operating day.

- **Emergency, Stage 1** – The CAISO declares a Stage 1 Emergency event when all available resources are in use. Additional DR, load reduction, and generation resource programs and activities are taken progressively.
- **Emergency, Stages 2 and 3** – The CAISO declares a Stage 2 or 3 Emergency event when it anticipates it can no longer meet energy requirements and is energy deficient. During Stage 2, the CAISO escalates Stage 1 activities and makes arrangements to drop firm load. Firm load interruptions occur during Stage 3.[18]

The MGCC Study Participants did not evaluate CAISO transmission emergencies because the DAHRTP price is restricted to generation costs only.

Table 1: AWE Event-Days 2010-2021[19]

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total	Avg
RMO	9	4	8	3	2	9	6	19	5	2	17	16	**100**	**8.3**
Flex Alert	-	2	2	3	1	2	2	4	2	1	10	8	**37**	**3.1**
Alert	-	-	-	-	-	1	-	-	-	-	9	-	**10**	**0.8**
Warning	1	1	-	-	1	1	-	-	-	1	7	4	**16**	**1.3**
Stage 1	-	-	-	-	-	-	-	1	-	-	-	-	**1**	**0.8**
Stage 2	-	-	-	-	-	-	-	-	-	-	6	1	**7**	**0.6**
Stage 3	-	-	-	-	-	-	-	-	-	-	2	-	**2**	**0.2**
Warning or Emergency	1	1	-	-	1	1	-	1	-	1	7	4	**17**	**1.4**

The MGCC Study Participants could not fully analyze AWE event conditions because the detailed description of CAISO Operating Procedure 4420B, the AWE Guide, is not publicly available; the CAISO has not shared much public detail regarding the factors that it considers when deciding to issue an AWE.

The MGCC Study Participants noted that RMOs were issued on a multiple day basis because they are directed at generating resources that require significant advance notification because of potentially long startup times. However, from a reliability perspective the occurrence of RMO hours during the

18 CAISO, Operating Procedure No. 4420, Version 13.2 (Oct. 21, 2021). Available at: http://www.caiso.com/rules/Pages/OperatingProcedures/Default.aspx.

19 As the CAISO sometimes calls events that span more than one day, an event-day is defined a day with an AWE event (of any number of hours). The primary source for these data is CAISO's AWE Grid History Report, available at: http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf. CAISO press releases, social media, and other publicly available information were used to correct data irregularities and fill in missing data.

off-peak periods is fairly meaningless—there is no suggestion that additional generation resources would result in the CAISO shortening RMO events to just the peak periods. Therefore, the MGCC Study Participants concluded that not all RMO hours should be considered.

The MGCC Study Participants concluded that the development of the MGCC pricing formula would only consider RMO event hours from 3 PM to 10 PM. Data supporting this decision can be found in Finding 5.6, where Figure 6 and Figure 7 illustrate the hourly incidence of Flex Alerts and W/E events. Focusing on the 2017-2021 time period, almost all of those events occurred between the hours of 3 PM to 10 PM.[20] In contrast, RMO events often begin much earlier than 3 PM – in fact, Figure 7 omits many RMO event hours that occurred before 10 AM. In addition to those data, the Participants also observed that the 3 PM to 10 PM period corresponds to PG&E's mid-peak and on-peak hours, except for the hour between 10 PM and 11 PM.

As noted above, Alerts are always issued on a DA basis and for the period analyzed in Table 1, they have always occurred on the same day as a Flex Alert, so they are referred to jointly as FA/A events. For purposes of analysis, Warning and Emergency events (which are issued day-of), are occasionally combined and may be referred to as W/E events. A total for these events is provided in Table 1 since a Warning is not necessarily issued prior to an Emergency.

4.1.4 Cutoff Time for Notifications to Participants

The MGCC Study Participants learned from PG&E staff that PG&E would like to communicate the DAHRTP price to pilot participants before approximately 4 PM each day. There is concern that a later notification may be significantly less convenient for participants.

Historically, CAISO has called a significant number of FA/A events between 4 PM and 6 PM. However, the MGCC Study Participants anticipate that due to a more formal link between FA/A events and DR programs, particularly for the ELRP, CAISO is likely to call almost all FA/A events prior to 4 PM.

Accordingly, for purposes of this study, the MGCC Study Participants found it reasonable to interpret RMO or FA/A events called before 6 PM as DA events for purposes of analysis. The Participants anticipate that there will be few, if any, events called between 4 PM and 6 PM. The Participants expect that PG&E will communicate the DAHRTP price to pilot participants before approximately 4 PM each day, but that from an analytic point of view, a 6 PM cutoff time should be used for historical data.

Accordingly, in certain analyses, a distinction is made between FA/A and RMO events that are called after 6 PM on the DA. Where making a distinction based on this historical 6 PM cutoff, events will be classified as either as DA or as Evening and/or Day-Of (EDO).

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20 Those Flex Alerts and W/Es in the 2017-2021 period that occurred earlier than 3 PM had load below the 99th percentile, suggesting that those event hours may have been included because the CAISO determined that it was important to address a more severe condition later in the day by initiating the event early. Moreover, while some of the Warnings in Figure 6 and Figure 7 begin in HE 13 and extend past 10 PM, the descriptions of those extended Warnings reference anticipated reserve shortfalls between the hours of 3 PM and 10 PM.

4.2 *Modeled Forecast Data*

4.2.1 Strategic Energy Risk Valuation Model Forecast Data

The Commission's Energy Division uses the Strategic Energy Risk Valuation Model (SERVM), a probabilistic reliability and production cost model, to validate the reliability, operability, and emissions of resource portfolios.[21] The Energy Division designed a 38 million metric tons (MMT) Core Portfolio Preferred System Plan to produce the 2021 Transmission Planning Process (TPP).

Evaluation of a resource portfolio by SERVM is configured for specific study years using a range of future weather, economic output, and unit performance (outages) assumptions. The 2021 TPP SERVM evaluation includes the following assumptions:

- **Study years:** Load and generation resource forecasts for 2022, 2026 and 2030
- **Weather:** Twenty weather years (1998-2017)[22]
- **Economic output:** Load forecasts varied by -2.5%, -1.5%, 0%, +1.5% and +2.5% the forecasted load
- **Unit performance:** Simulation of hourly economic unit commitment and dispatch using 50 stochastic draws of possible outages
- **Import constraint:** Imports are constrained to a level that cannot exceed 4,000 megawatts (MW) from 4 pm to 10 pm, June through September[23]

Modeling twenty weather years with five load forecast variations results in 100 cases for each forecast year, with each SERVM case representing 50 random stochastic draws of possible generation and transmission system outages. SERVM outputs include forecasts for a number of variables; for purposes of the MGCC Study, four Grid Stress metrics were identified as variables of interest: (1) the hourly amount of EUE, shortages in (2) Non-Spin Reserve and (3) Upward Reserve resources,[24] and dispatches of (4) reliability DR.

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[21] The following description of SERVM and its application by the Energy Division is found in Energy Division presentations: SERVM Production Cost Modeling Results (Dec. 17, 2021), available at ftp://ftp.cpuc.ca.gov/energy/modeling/IRP_PSPo_2020IEPR_HEV_SERVM_final.pdf; and Reliability and GHG Modeling Results (August 17, 2021), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/psp-servm-ruling-presentation.pdf.

[22] It is not possible to directly match forecast and historical data based on weather year because the forecast loads and generation data differ substantially from the loads and generation that occurred in the actual historical year. For example, it is not reasonable to assume that an AWE event that occurred on August 1, 2015 would also occur on August 1 in the 2022 SERVM forecast using the 2015 weather year, because there would be significantly more solar and short-duration energy storage resources in the SERVM run, as well as fewer gas-fired resources.

[23] CPUC Energy Division, Reliability and GHG Modeling Results, Aggregated Load Serving Entity (LSE) Plans, 38 MMT Core Portfolio (Aug. 17, 2021), Energy Resource Modeling Team, p. 23.

[24] SERVM refers to Non-Spin resources as Quick-Start resources. Upward Reserve resources are the sum of Regulation Up plus Spinning Reserves.

The Energy Division provided the MGCC Study Participants several sets of SERVM forecast data, as summarized in Table 2. Energy Division's practice is to retain summary data for all 100 cases and detailed hourly data for only ten cases. No details are retained that can be attributed to the individual stochastic draws. It was understood that the ten cases with detailed hourly data are supposed to be those with the highest EUE. However, as shown in Table 3, hourly data were retained for only six of the ten highest-EUE cases for the 2026 forecast with the remaining four cases corresponding to very low EUE levels.[25]

Table 2: SERVM Forecast Cases Provided by the Commission's Energy Division

Dataset	2022	2026	2030
Annual Summary Data – 100 Cases	High-load Sensitivity Case	Base Case	Base Case
Hourly Data – 10 Cases	Base Case	Base Case	Base Case

25 The ten detailed hourly cases for the 2022 forecast also appears to include some cases with EUE levels that are not very high. However, since the ten detailed hourly cases are not comparable to the 100 summary data cases, it is impossible to determine whether the 2022 hourly cases did or did not represent the highest-EUE cases.

Table 3: Hourly Data Availability for 2026 SERVM Forecast Cases

Case Number	Load Forecast	Weather Year	EUE	Hourly Data Retained	Case Number	Load Forecast	Weather Year	EUE	Hourly Data Retained
99	2.5	2017	9,410		**18**	-1.5	2001	-	
97	1.5	2017	5,806		**20**	-2.5	2001	-	
44	2.5	2006	5,104	Yes	**21**	0	2002	-	
89	2.5	2015	2,803	Yes	**22**	1.5	2002	-	
87	1.5	2015	2,398	Yes	**23**	-1.5	2002	-	
42	1.5	2006	1,904	Yes	**25**	-2.5	2002	-	
96	0	2017	1,201		**26**	0	2003	-	
4	2.5	1998	998	Yes	**27**	1.5	2003	-	
41	0	2006	802	Yes	**28**	-1.5	2003	-	
74	2.5	2012	513		**29**	2.5	2003	-	
47	1.5	2007	340		**30**	-2.5	2003	-	
98	-1.5	2017	308		**31**	0	2004	-	
84	2.5	2014	251		**32**	1.5	2004	-	
43	-1.5	2006	241		**33**	-1.5	2004	-	
72	1.5	2012	217		**34**	2.5	2004	-	
45	-2.5	2006	207		**35**	-2.5	2004	-	
49	2.5	2007	169		**36**	0	2005	-	
2	1.5	1998	153		**37**	1.5	2005	-	
82	1.5	2014	120		**38**	-1.5	2005	-	
76	0	2013	117		**39**	2.5	2005	-	
86	0	2015	116		**40**	-2.5	2005	-	
94	2.5	2016	95		**48**	-1.5	2007	-	
100	-2.5	2017	70		**50**	-2.5	2007	-	
71	0	2012	60		**51**	0	2008	-	
73	-1.5	2012	31		**52**	1.5	2008	-	
17	1.5	2001	28		**53**	-1.5	2008	-	
14	2.5	2000	23		**54**	2.5	2008	-	
88	-1.5	2015	16		**55**	-2.5	2008	-	
3	-1.5	1998	15	Yes	**56**	0	2009	-	
91	0	2016	10		**57**	1.5	2009	-	
12	1.5	2000	10		**58**	-1.5	2009	-	
78	-1.5	2013	9		**59**	2.5	2009	-	
46	0	2007	5		**60**	-2.5	2009	-	
19	2.5	2001	5		**61**	0	2010	-	
79	2.5	2013	4		**62**	1.5	2010	-	
77	1.5	2013	4		**63**	-1.5	2010	-	
81	0	2014	4	Yes	**64**	2.5	2010	-	
24	2.5	2002	2	Yes	**65**	-2.5	2010	-	
83	-1.5	2014	0	Yes	**66**	0	2011	-	
1	0	1998	-		**67**	1.5	2011	-	
5	-2.5	1998	-		**68**	-1.5	2011	-	
6	0	1999	-		**69**	2.5	2011	-	
7	1.5	1999	-		**70**	-2.5	2011	-	
8	-1.5	1999	-		**75**	-2.5	2012	-	
9	2.5	1999	-		**80**	-2.5	2013	-	
10	-2.5	1999	-		**85**	-2.5	2014	-	
11	0	2000	-		**90**	-2.5	2015	-	
13	-1.5	2000	-		**92**	1.5	2016	-	
15	-2.5	2000	-		**93**	-1.5	2016	-	
16	0	2001	-		**95**	-2.5	2016	-	

4.2.2 Limitations of SERVM Forecast Data

There were several limitations to the SERVM forecast data provided by the Energy Division. First, the hourly data cases do not represent an ideally constructed statistical representation of the relationship between reliability, load, and generation.

- Each case represents the average of 50 stochastic model iterations. While suitable for many purposes, this averaging process conceals a certain amount of statistical variation that would be useful for analysis.
- Energy Division retained, and made available, hourly data for only ten of the 100 cases for each forecast year.
- Energy Division confirmed by email on November 23 that the ten cases retained are not the cases with the highest EUE; it is unclear how the Energy Division selected the ten cases.
- For the 2022 forecast year, two of the ten cases included very unusual results that do not appear in any of the 2026 or 2030 hourly cases, nor in the summary results from the 100 2022 high-stress cases, thus, the Study Participants decided to exclude these two cases from the analysis.
- For the 2022 forecast year, the summary data for the 100 cases are from a different (high-load sensitivity) model run than the ten supplied hourly cases. This makes it difficult to understand how the hourly cases relate to the full 100 case SERVM analysis.

Second, Energy Division did not provide all SERVM data that could have been useful for completing the study. Specifically, Energy Division redacted Operating Reserve Demand Curves and pricing data from the output files due to concerns about its validity. The MGCC Study Participants understood the concerns of Energy Division, but this decision resulted in a need to conduct further research to obtain alternate references.

Third, and most significant, the 4,000 MW import limit during the summer peak period created an insurmountable challenge to the use of the SERVM data to directly inform the rate design. During hours in which the import limit is effective, the model indicates a corresponding increase in thermal dispatch. This results in an increased probability of EUE during hours in which the modeled import limit is in effect. While the intent of the summer peak period import limit is to reflect existing RA contracts and capture the import limitation experienced during recent summer months, imports during June-September from 4-10 PM during 2020 and 2021 have actually exceeded 4,000 MW in 85% of the hours in which the CAISO GL was above 37,000 MW (with an average over those hours of 6,160 MW)—and for 5-10 PM imports exceeded 4,000 MW in *all* of the high-load summer hours.[26]

Furthermore, the import limit is not sensitive to load conditions that could actually constrain imports. During summer peak hours when CAISO net load is relatively high, modeled imports are near 4,000 MW – regardless of the level of load or net load in non-CAISO regions, which may be low due to relatively mild weather or high renewable generation, or high due to very hot conditions, especially close to sunset.

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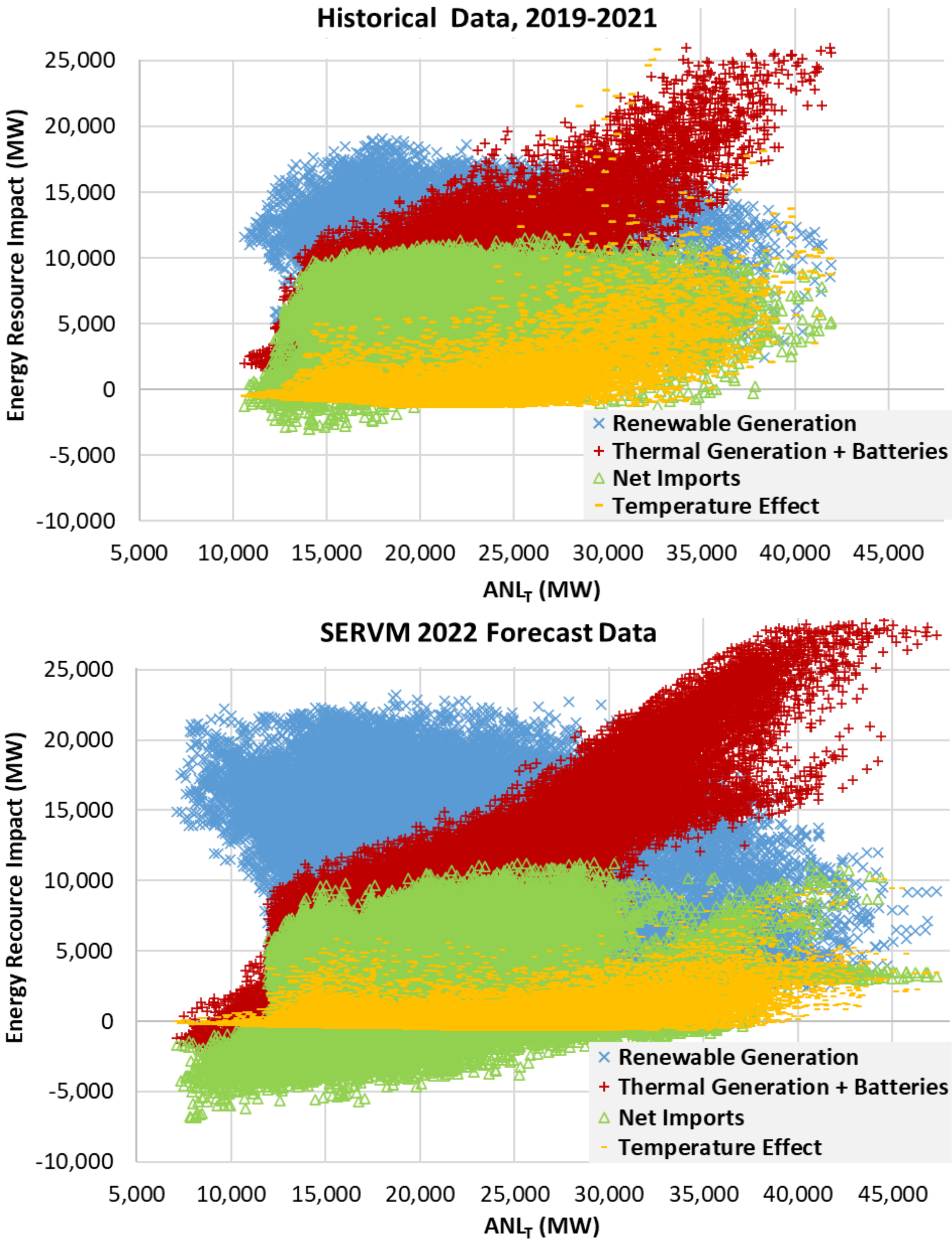
26 MGCC Study Participants recognize that historical data may not reflect future import levels and import patterns.

The differences between the historical and model forecast data are illustrated in Figure 2, below.

Figure 2: Energy Resource Impact, Comparison of Historical and Modeled Forecast Data



Some of the differences shown in Figure 2 are to be expected. Renewable generation is higher in the forecast model due to assumed continued renewables buildout. The higher renewables level results in increased net exports (illustrated as negative imports at low loads). However, a “spike” in net imports is visible at high loads; the spike is a result of the 4,000 MW import ceiling in summer peak hours, and only appears in the model forecast data.

As a result of the potential shifts in hourly EUE and insensitivity of imports to weather conditions, the MGCC Study Participants determined that the reliability metrics with temperature adjustments could not be used. The Participants agreed that one consequence of the 4,000 MW import limit is that EUE may be relatively overstated or understated on an hourly basis. In general, SERVM runs with or without an import limit should have roughly the same total EUE since the resource mix is selected to achieve a reliability target (usually expressed as loss of load expectation). The use (or non-use) of an import limit will affect the distribution of EUE across the year, with some hours having elevated EUE and others having reduced EUE.

When net load is high in non-CAISO regions, which would reduce CAISO import availability, the 4,000 MW import limit may reasonably represent actual conditions.[27] However, when net load is low in non-CAISO regions, the artificial 4,000 MW import limit may underestimate CAISO imports and result in relatively *overstated* EUE for those hours. In turn, because total EUE is driven by the reliability target, overstating EUE in some hours likely means that some high-load hours will have relatively *understated* EUE.

Even more important than the potential shift in EUE hours for the MGCC Study rate design effort is that the 4,000 MW SERVM import limit removes the temperature-dependence of import availability during high net load hours. As shown in Figure 2 for the 2022 forecast case on the right, during high net load hours, imports are almost always 4,000 MW, irrespective of the modeled load impact due to non-CAISO temperatures (“Temperature Effect”).

As explained in Finding 5.4, the MGCC Study Participants agreed that ANL_T is the net load metric that is best associated with AWE events because the use of forecast temperature data for non-CAISO regions helps to predict the availability of imported power. The import limit included in SERVM modeling removed any significant variation in imported power during summer peak hours, resulting in hourly SERVM results that showed no relationship between temperature and grid stress. For this reason, it was not possible to use the SERVM data to conduct an hourly analysis of grid stress using the most accurate load metric (ANL_T).

4.2.3 Grid Stress Metrics in SERVM Forecast Data

Although the MGCC Study Participants did not use the SERVM data due to the shortcomings in the datasets discussed in Section 4.2.2, the Participants determined that the modeled forecast data includes four reliability metrics that could potentially be used in the future to refine the hourly MGCC price curve. If inconsistencies identified in Section 4.2.2 were addressed, including more dynamic

[27] MGCC Study Participants understand that the SERVM Import constraint was chosen to model relatively conservative possible future conditions in a planning context, and that CAISO determined the constraint to be appropriate for the use case for which it was designed.

modeling of imports during the summer peak period,[28] then a Grid Stress metric could be developed using SERVM forecast results to inform the hourly MGCC price curve.

The MGCC Study Participants see some advantages to using hourly SERVM data to verify or refine the hourly MGCC prices in the future. Use of the SERVM data to refine the MGCC price curve after the pilot is completed might be beneficial because the SERVM dataset includes assumptions (e.g., loads, generation resource mix) that are meant to represent future conditions (e.g., 2022 and 2026) that are more closely aligned with prevailing conditions when the rate would be implemented than historical CAISO events data. In addition, the SERVM production cost modeling results include a high degree of hourly variability across several metrics that represent a range of reliability risk levels, which theoretically makes it a useful dataset for predicting hourly changes in system capacity costs.

However, as demonstrated in Finding 5.7.3, the reliability metrics in SERVM forecast data exhibit considerable inter-annual variability. Therefore, formulating a pricing function based on the single Grid Stress metric, as discussed below, would need to be tempered so as to keep the interannual variability to a reasonable level.

The SERVM forecast data includes four outputs that indicate increasing levels of grid stress and reliability impacts: Upward Reserve shortfall, Non-Spin Reserve shortfall, dispatch of reliability DR, and EUE, as discussed in Section 4.2.1. The two reserve shortfalls are associated with types of ancillary services. EUE corresponds to energy deficiency and firm load interruptions (Stage 2 and 3 Emergencies). For convenience, these four outputs are collectively referred to as the reliability metrics.

If SERVM forecasts were developed with a refined (or removed) summer peak import constraint, it would be possible to develop a function to relate ANL_T to the reliability metrics by weighting each of the reliability metrics by its relative cost to the system (price) and combining the four weighted reliability metrics into a single Grid Stress metric. The MGCC Study Participants identified two possible methods for determining the weight of each reliability metric.

First, SERVM includes price-related outputs that might possibly provide a reasonable basis for weighting the reliability metrics. The MGCC Study Participants could not verify this, however, because the Energy Division did not provide price-related outputs (see Section 4.2.2).

The second method would rely on available CAISO market operational parameters and SERVM data. Values on a $ per MWh basis for three of the four reliability metrics are included in CAISO market optimization software parameters,[29] and a value for DR is available from SERVM modeling practices.

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28 MGCC Study Participants recognize that the import limits used in the SERVM model reflect existing import RA contracts. It is likely that that the CAISO market may import energy higher than RA contract levels, particularly when net loads in the rest of the Western Electricity Coordinating Council (WECC) are not extremely high. Ideally a robust WECC model would reflect resource plans of all LSEs and simulate market frictions to replicate WECC wide operation. In the absence of a robust WECC wide model of non-CAISO entities' resource plans, MGCC Study Participants offer a recommendation to use historical import levels correlated with WECC-wide LSE net loads to inform modeled maximum imports.

29 California ISO, Business Practice Manual for Market Operations (Version 79, Rev. Jan. 25, 2022), pp. 246-252. Available at: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations.

Under conditions of Grid Stress, the CAISO procures ancillary services (including reserves) up to a maximum price. Above that price cap (known as the penalty price), the CAISO prioritizes energy procurement over operational reserves. The CAISO has set the penalty price for ancillary services at $248-250 per MWh. (The three $1 price steps allow the model to have a "shortfall order" based on the sequence of the price caps for different ancillary service requirements.) Based on these practices, the two reserve metrics could each be valued at $250 per MWh.

The CAISO market rules allow energy procurement to occur at prices up to $2,000 per MWh ($2 per kWh).[30] When this price cap is reached, conditions of energy deficiency (Stage 2 Emergency) and load interruptions (Stage 3 Emergency) may occur. Based on this practice, EUE could be valued at $2,000 per MWh.

The SERVM inputs provided by the Energy Division state that the vast majority of DR resources are modeled as dispatched at a price of $600 per MWh. The remainder is dispatched at a price of $1,000 per MWh. Based on the SERVM input assumptions, and for simplicity, DR could be valued at $600 per MWh.

The reliability metrics could be weighted based on these practices to form a single Grid Stress metric, as shown in Table 4. Such a Grid Stress metric would be calculated on an hourly basis by multiplying the level of each reliability metric times the value-derived weighting factor. For example, if an hour has shortfalls of 100 MWh of Upward Reserve and 100 MWh of Non-Spin reserve, but no EUE or DR, then the Grid Stress metric would be 16.2 MWh (100 x 8.1% x 2). This hourly Grid Stress metric could be used to construct an equation relating a DA load metric, such as $ANL_{T,}$ to the combined hourly capacity stress (grid stress) on the system.

Table 4: Potential Grid Stress Metric Weighting Factors

Reliability Metric	Value	Weighting Factor
Expected Unserved Energy (EUE)	$2,000 per MWh	64.5%
Demand Response (DR)	$600 per MWh	19.3%
Upward Reserve Shortfall	$250 per MWh	8.1%
Non-Spin Reserve Shortfall	$250 per MWh	8.1%

The MGCC Study Participants did not complete development of a final Grid Stress metric. Three steps would need to be taken to complete its development. First, the shortcomings in the SERVM forecast data discussed in Section 4.2.2 would need to be addressed. Second, any updates to the weighting factors would need to be considered, or potentially substituted with price-related model output data if made available. Third, the application of the Grid Stress metric in an MGCC pricing curve would need to be refined in order to balance the interest in more accurately reflecting grid stress with the importance of avoiding dramatic swings in revenue collection from year to year.

30 CAISO used a $1,000 MWh price cap through spring 2020, but per FERC Order 831 increased the price cap to $2,000 per MWh on June 13, 2021. https://www.caiso.com/Documents/Presentation-2021SummerReadinessUpdateCall-June23-2021.pdf.

Nonetheless, the MGCC Study Participants found that development and testing of the Grid Stress metric was informative regarding the relative contribution of the reliability metrics to overall grid stress. The general S-shape of the SERVM reliability metrics, which indicated that some forms of grid stress begin to increase at relatively low levels of net load, is reflected in the study's final recommended rate design in Section 6.2. This qualitative corroboration boosted the Participants' confidence in the research findings in Section 5. Furthermore, the MGCC Study Participants found the *annual* SERVM forecast data useful for assessing inter-annual variability, as discussed in Finding 5.7.3.

5 Research Findings

The MGCC Study Participants report the following findings based on their analysis of historical DA load forecasts and CAISO AWE events.

5.1 *Finding: DA Hourly Forecast Data Are More Useful Than 15- or 5-Minute RT Data for Design of a DAHRTP Rate.*

D.21-11-017 approved the use of CAISO's DA pricing and average Default Load Aggregation Point (DLAP) loss factor for the MEC component of the DAHRTP rate.[31] The MGCC Study Participants found that the MGCC component of the DAHRTP rate should also use the DA hourly load forecast data.

CAISO's energy market can be subdivided into three market products. CAISO produces a load forecast for both DA and day-of-market purposes. The vast majority of transactions take place in the DA markets while the day-of markets are used primarily to balance resources with actual loads. The CAISO's day-of-market pricing includes the Fifteen Minute Market and a five-minute market, or Real-Time Dispatch market. The day-of-market pricing products are not useful for a dynamic RTP rate design at this time. The final cost of energy procured through these two markets is often not known until later in the day, or perhaps further into the future, as CAISO must true-up actual energy deliveries. Perhaps more importantly, these products represent a relatively small minority of total energy consumption. The actual cost of energy to customers is best reflected by the DA market price.

Another important and practical reason to prefer DA pricing is that it can be supplied to participants in advance via a DAHRTP rate notification, allowing participants to optimize energy use or storage decisions for their business or home over the following day. For the same reasons, the CAISO DA hourly load forecast should be used for the design of a DAHRTP rate.

5.2 *Finding: A DAHRTP Rate Should Not Be Geographically Differentiated.*

For several reasons, a dynamic RTP rate is best offered across the entire PG&E system for generation costs only. In testimony, parties considered the potential for a geographically differentiated rate that takes into consideration varying conditions on PG&E's distribution system. However, there is evidence that it would be costly and confusing to customers to offer a geographically differentiated rate. Differentiating pricing based on distribution systems would require frequent updates, as pricing reflects the potential to defer additional investment. That potential may change as actual or forecasted customer load enters or exits the system, or when distribution investments are placed in service. Thus, incorporating area-based distribution rates would add substantial complexity to PG&E's information and billing systems, and could potentially confuse customers with accounts in multiple areas. Many of these same concerns would apply even if geographically differentiated rates were only used for

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[31] D.21-11-017, pp. 9-10.

generation costs, which can differ within PG&E's DLAP.[32] Moreover, PG&E and all other LSEs within its service territory (such as Community Choice Aggregators) actually settle (or pay for) load at the DLAP, not the finer granularity used for generation resources.[33] Accordingly, PG&E's billing system does not track customers by sub-LAP. Indeed, there is relatively little differentiation in generation prices between sub-LAPs.[34]

It should be noted that, except for multiple RMO orders and a single Flex Alert issued by CAISO for Southern California, all of the AWEs in the historical record are at the CAISO level or apply to Northern California. Other than excluding Southern California AWEs from various analyses, the evaluation of generation reliability did not require differentiation between the PG&E system and other CAISO areas.

5.3 FINDING: AWE Events Are a Good Indication of Generation-Related Grid Stress or Reliability Events.

The CAISO calls AWE events when it anticipates grid stress or even the need to drop load. Generation-related events may be caused by high demand, supply shortfall (due to generator outages, fuel constraints, or low amounts of variable resource generation), and transmission constraints (congestion or outages). Based on CAISO's definitions and practice, the MGCC Study Participants found that the seven types of AWE events listed in Section 4.1.3 are a good indication of the potential for generation-related grid stress or reliability events.[35] Furthermore, the MGCC Study Participants found that AWE event hours are disproportionately represented in the highest 10% load hours.[36]

5.4 FINDING: ANL_T is the Net Load Metric That Is Best Correlated With AWE Events.

The MGCC Study Participants evaluated the six net load metrics described in Section 4.1.2 to determine which were most closely correlated with AWE events and determined that ANL_T performed best overall. By adjusting NL to account for non-CAISO system conditions using weather stations at PHX and SEA, ANL_T recognizes the relationship between extreme heat or cold and the lack of regional generating

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32 The PG&E DLAP is a load-weighted average node (load source) that averages all the locational marginal price nodes within PG&E's service territory. The DLAP is the only point within PG&E's territory where power purchases are made, so all of PG&E's electricity purchases in CAISO markets occurs at PG&E DLAP prices.

33 For example, see https://www.caiso.com/InitiativeDocuments/SVPComments-ReviewTransmissionAccessChargeStructure-WorkingGroupMeetings-Aug29-Sep25_2017.pdf.

34 A.20-10-011, Exhibit PG&E-1, Ch. 2, pp. 2-12 to 2-15.

35 The MGCC Study Participants also evaluated Base Interruptible Program (BIP) events. Most of the non-local BIP events occurred in August and September 2020, and generally coincided with DA RMO, DA Flex Alert, Warning, and Stage 2 Emergency events. They found that the BIP events did not add significant value to the quantitative analyses but contribute to an understanding of the relationship between AWEs and DR dispatch.

36 For example, as measured using ANL_T, 87% of all AWE event hours (of any type) occur during hours with loads in the top 10th percentile and 72% occur during hours with loads in the top 5th percentile.

resources.[37] High temperatures often increase plant outages, while both high and extreme low temperatures increase load levels outside of the CAISO system. Extreme temperatures outside of the CAISO can therefore reduce the availability of imported power and exacerbate supply and demand imbalances on the CAISO system.

The MGCC Study Participants reviewed the frequency of all types of AWE events (RMOs, Flex Alerts, and W/Es) in various combinations as compared to the six candidate load metrics, considering both the full 2010-2021 period as well as a limited 2017-2021 period to focus on years with higher solar penetration. Based on many different combinations of AWE event types and different periods, the MGCC Study Participants concluded that the ANL_T is the net load metric that best balances alignment with AWE events and simplicity.

For example, there were 31 Alerts, Warnings or Emergency events[38] that indicated anticipated or actual grid stress from 2017-2021. Table 5 below shows the frequency (probability) of any such AWE event occurring on the system as the load metric increases. The columns represent the six different load metrics, while the rows represent the level of CAISO load expressed as a percentile over the entire dataset (2017-2021). Roughly one quarter of the recorded event hours occurred when loads were in the top 0.1% of all hours. Thus, a load metric that is a strong predictor of AWE events would show low probability of AWE events at low load levels and would increase to a high probability of an event at high load levels (in the top 0.1% of all hours). As shown in Table 5, ANL_T had the second highest frequency of such events (54.55%) during the top 0.1% of all hours, while ANL_{RT} (which also subtracts hydro and nuclear generation) had a slightly higher frequency of 56.82% in the highest 0.1% of hours.

Table 5: Alerts and Warning Event Frequency Compared to Candidate Load Metrics, 2017-2021,
Frequency of hours with any of the following: Alerts, Warnings, or Emergency (of any stage)

Percentile	GL	NL	ANL_R	ANL_T	ANL_{RT}	ANL_{RTG}
< 90 %	0.00%	0.01%	0.01%	0.00%	0.00%	0.00%
90 – 95 %	0.14%	0.18%	0.27%	0.14%	0.14%	0.23%
95 – 97 %	0.80%	0.91%	0.80%	1.03%	0.91%	0.34%
97 – 99 %	2.17%	2.05%	1.83%	1.48%	1.60%	2.05%
99 – 99.6 %	7.60%	5.70%	5.70%	6.46%	5.32%	5.32%
99.6 – 99.8 %	14.77%	12.50%	10.23%	4.55%	7.95%	11.36%
99.8 – 99.9 %	15.91%	20.45%	25.00%	31.82%	29.55%	29.55%
99.9 – 100 %	34.09%	38.64%	43.18%	54.55%	56.82%	50.00%

Depending on the particular AWE event types and time periods examined, other metrics such as ANL_{RT} or ANL_{RTG} may have slightly better performance than ANL_T. However, ANL_T also has two other advantages over other candidates. First, it is simpler to explain. Second, it has less inter-annual variability than metrics that include hydro generation. The MGCC Study Participants evaluated several approaches for hydro generation, but because they did not present any evident advantages over the

37 The best temperature coefficients for use in the ANL_T metric were determined using a logistic regression of the probability of RMO event hours. The logistic regression is described in Section 6.1.

38 In other words, AWE events excluding Flex Alerts and RMOs.

simpler formulation and would have required further analysis to reach agreement, the Participants agreed to exclude hydro generation from the recommended net load metric.

The MGCC Study Participants concluded that the ANL_T is the net load metric that is best associated with AWE events because under nearly all event types and time periods examined it had the highest or among the highest frequency of events at the high load percentiles, and because the other similar-performing metrics were more complex to calculate and explain to customers than ANL_T.

5.5 *FINDING: High Net Load Occurs From June To October and in Recent Years, Has Been Concentrated Between 3 PM and 10 PM.*

Using the ANL_T metric, high net load occurs from June to October, as illustrated in Figure 3.

Figure 3: Proportion of ANL_T in Top 1 Percentile by Month and Hour Ending, 2010-2021

	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	1%	4%	6%	7%	8%	9%	7%	2%	0%	0%	3%
7	0%	0%	1%	2%	5%	10%	12%	15%	17%	16%	10%	1%	0%	0%	6%
8	0%	0%	3%	5%	9%	16%	21%	22%	24%	21%	16%	3%	0%	0%	10%
9	0%	0%	0%	3%	7%	10%	11%	13%	13%	11%	5%	2%	0%	0%	5%
10	0%	0%	0%	1%	1%	1%	1%	2%	1%	1%	0%	0%	0%	0%	1%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average		**0%**	**0%**	**1%**	**2%**	**3%**	**4%**	**5%**	**5%**	**5%**	**3%**	**1%**	**0%**	**0%**	

As illustrated in Figure 4, in recent years, high net load is concentrated between 3 PM and 10 PM.[39] The shift towards a later, more concentrated peak net load period is consistent with the impact of solar power development on the CAISO system.

39 All figures and charts depicting historical data show HE in Pacific Prevailing Time (i.e., including the influence of Daylight Saving Time). For example, HE 19 in June represents the time period of 6 PM to 7 PM, Pacific Daylight Time.

Figure 4: Proportion of ANL_T in Top 1 Percentile by Month and Hour Ending, 2017-2021

	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	3%	6%	8%	11%	13%	12%	4%	0%	0%	4%
7	0%	0%	0%	0%	1%	3%	5%	9%	17%	24%	15%	2%	0%	0%	6%
8	0%	0%	0%	0%	2%	9%	16%	22%	30%	34%	25%	8%	0%	0%	10%
9	0%	0%	0%	0%	2%	5%	6%	12%	18%	16%	10%	4%	0%	0%	5%
10	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average		0%	0%	0%	0%	2%	3%	4%	7%	7%	5%	2%	0%	0%	

It is also worth noting that the MGCC Study Participants observed similar patterns in the Grid Stress metric that was developed using SERVM forecast data. Although the MGCC Study Participants did not conclude analysis of hourly SERVM forecast data due to the shortcomings in the datasets discussed in Section 4.2.2, those shortcomings are unlikely to have substantial effects at a seasonal scale, or even when aggregating those data in a 12x24 format. The MGCC Study Participants can confirm that the same general patterns (June – October, afternoon/evening) are observed in the 2022 and 2026 SERVM forecast data.

5.6 FINDING: High Net Load Contributes to, But Does Not Fully Explain, Grid Stress and Reliability Events.

As noted in Finding 5.4, while AWE event hours are concentrated in the highest 5th or 10th percentile loads, there are still some AWE event hours that occur during lower load hours. Furthermore, even for hours with net load in the top 0.1% of all loads, no AWE event of any type (excluding RMOs) was called for roughly 20% of those hours. Both of these observations are unsurprising.

- Even when net load significantly exceeds the weather normal peak load forecast, the CPUC and the CAISO have directed LSEs to procure reserves, the level of which is planned to accommodate uncertainties such as unexpected resource outages.[40] When the level of outages is low, those resources can be expected to operate at nearly full capacity, and system distress does not develop despite very high loads.

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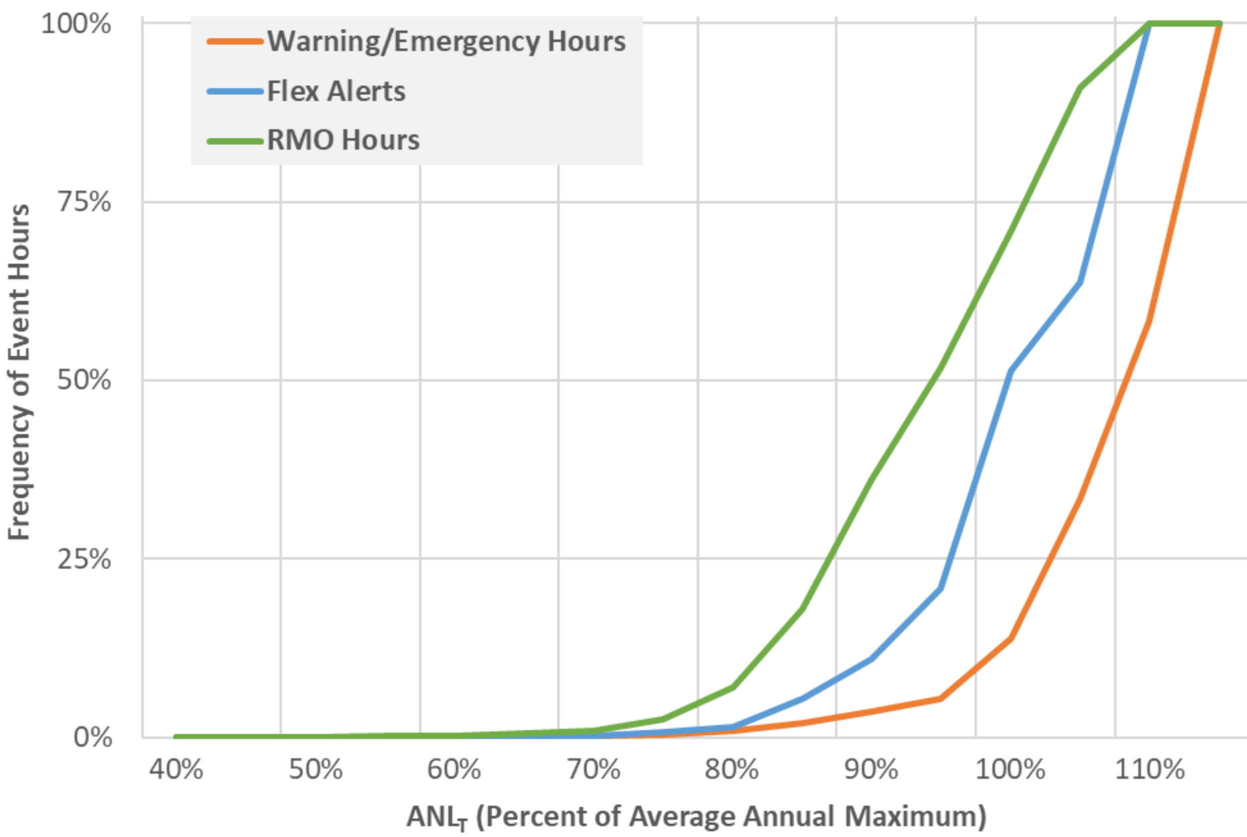
40 CPUC-jurisdictional load-serving entities must procure sufficient capacity to meet their expected 1-in-2 weather year peak load plus a 15% PRM according to current Resource Adequacy requirements. In D.21-03-056, the Commission temporarily increased the PRM to a minimum of 17.5% above expected peak demand for summer 2021 and 2022.

- Even when net load is significantly below the weather normal peak load forecast, other factors may contribute to system distress, such as reduced reserve levels caused by resource outages (loss of generator or transmission line) or resource limitations due to reduced availability of natural gas fuel caused by a polar vortex event or the Aliso Canyon gas storage incident.

The MGCC Study Participants determined that it is important to recognize the imperfect causal relationship between net load and grid stress and reliability events in the design of the MGCC component of the DAHRTP rate. Ideally, that rate will provide a price signal to DAHRTP participants that is highest when both the probability and severity of a generation reliability constraint are highest. Similarly, if either the probability or the significance of a generation reliability constraint is very low, then the MGCC component price should also be low.

While later findings will describe in more detail the relationship between net load and reliability, this finding demonstrates that on a meaningful number of days with high net load hours, the CAISO does not perceive any grid stress or reliability concerns. However, as shown in Figure 5, the probability of each of the three categories of AWE events increases with adjusted net load.

Figure 5: AWE Hour Frequency, Relationship to Peak Adjusted Net Load (ANL_T), 2010-2021[41]



41 The x-axis scale goes above 100% because some years (in particular, 2020) had significantly higher maximum loads than the average, which was calculated based on 2010 through 2021.

A more in-depth look at the relationship between AWE events and net load helps illustrate the effect of other factors on grid stress and reliability events. Figure 6 shows heat maps for DA RMO and Flex Alert events, EDO Flex Alerts, and W/E events for hours with peak loads *above* the 99th percentile, and Figure 7 shows the same heat maps for hours with peak loads *below* the 99th percentile.

AWE event hours in Figure 6 show an unsurprising and consistent pattern for higher loads. For lower loads (Figure 7), especially during the earlier pre-2017 (low solar) years, AWE events sometimes occurred outside the June-October period, and sometimes relatively early in the day. The EDO Flex Alerts are a potentially strong indication of events that could not be anticipated by a DA net load signal alone.

Figure 6: Number of AWE Event Hours by Month and Hour Ending with ANL_T Above 99th Percentile

DA RMO

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	3	4	4	4	4	4	-	-	-
7	-	-	2	2	2	5	5	5	5	5	5	1	-	-
8	-	-	2	3	3	4	6	6	6	5	4	-	-	-
9	-	-	-	-	1	2	2	2	2	2	-	-	-	-
10	-	-	-	1	1	1	1	1	1	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	4	5	7	8	8	3	-	-
7	-	-	-	-	1	2	4	4	7	7	5	2	-	-
8	-	-	-	-	2	9	14	17	20	20	20	9	-	-
9	-	-	-	-	2	4	5	7	10	10	7	4	-	-
10	-	-	-	-	-	-	-	1	1	1	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

DA Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	1	1	1	2	2	2	2	1	1	-	-	-
8	-	-	2	2	2	2	2	2	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	1	2	2	2	1	-	-
7	-	-	-	-	-	-	-	-	2	2	1	-	-	-
8	-	-	-	-	-	5	5	5	5	5	5	5	-	-
9	-	-	-	-	1	2	3	5	6	6	5	1	-	-
10	-	-	-	-	-	-	-	1	1	1	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EDO Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	1	1	1	1	1	-	-	-
7	-	-	1	1	1	1	1	1	1	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	1	1	1	1	1	1	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	1	1	1	1	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Warning or Stage 1,2,3 Emergency

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	1	1	1	1	1	1	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	1	1	1	1	1	1	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	1	1	-	-	-
7	-	-	-	-	-	-	-	-	2	3	3	-	-	-
8	-	-	-	-	2	5	5	5	5	5	4	3	-	-
9	-	-	-	-	-	-	1	1	2	2	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 7: Number of AWE Event Hours by Month and Hour Ending with ANL_T Below 99th Percentile[42]

DA RMO

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	2	2	2	1	1	1	1	1	1	1	1	1	1	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	4	4	4	4	4	1	-	-	-	-	-	4	3	-
7	6	6	4	4	4	1	1	1	1	1	1	5	4	-
8	6	6	4	3	3	2	-	-	-	1	1	5	-	-
9	2	2	2	2	1	-	-	-	-	-	2	2	1	-
10	1	1	1	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	4	4	8	8	8	7	4	3	1	-	-	5	3	-
7	6	6	8	8	7	6	5	5	2	2	4	4	1	-
8	19	19	23	23	21	14	9	6	3	3	2	13	10	-
9	7	7	10	10	8	6	5	3	-	-	3	3	5	-
10	3	3	3	3	3	3	3	2	2	2	3	3	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

DA Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	1	-	-	-	-	-	-	-	-	-
8	-	1	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	3	3	1	1	2	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	1	-	2	3	1	-	-	1	-	-	-
10	-	-	-	-	-	2	2	1	1	1	2	2	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EDO Flex Alert

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	1	1	1	1	1	1	1	1	1	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	1	1	1	1	1	1	1	1	1	1	1	1	1	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	1	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	1	-	-	-	-	-	-	-	1	1	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Warning or Stage 1,2,3 Emergency

2010-2016 (low solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	1	1	1	1	1	1	1	1	1	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	1	1	1	1	1	-	-	-	-	-	-	1	1	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	1	-	-	-	-	-	-	-	1	1	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2017-2021 (high solar)

	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	1	1	1	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	2	2	1	1	2	1	-
8	-	-	5	5	3	-	-	-	-	-	-	-	3	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-

42 Note that some DA RMO hours occurred earlier than the hours shown in this figure. The figure is constrained to HE 11 – 24 to focus on features of interest.

5.7 *FINDING: A Reasonable Standard for Inter-Annual Variability Is a Coefficient of Variation (CV) of up to 0.4.*

Some inter-annual variability in generation cost recovery from a DAHRTP rate is inevitable, and perhaps even desirable—higher rates in years with more grid stress are reasonably balanced with lower rates in years with less grid stress. The MGCC Study scope directs this report to consider "what level of intra- and inter-annual variation is most appropriate and would most accurately capture varying levels of capacity shortfall risk within a year and across multiple years."[43]

To put the variability of generation revenue recovery for the RTP rate into perspective, the MGCC Study Participants determined how much inter-annual variability occurs in actual generation energy and capacity costs from year to year. While there is no directly comparable measure of the annual cost to procure long-term capacity requirements, three types of capacity-related benchmarks provide an indication of the level of variation that might be reasonable to accept for an MGCC pricing formula, as follows.

- **Historical record** – Variation in load, net load, and energy prices
- **Resource adequacy** – Variation in weighted average RA prices
- **SERVM Grid stress metrics** – Variation in EUE, DR and reserve shortfalls

For each metric included in the three benchmark evaluations, a CV is calculated to indicate inter-annual variability relative to the average value, generally calculated as the standard deviation divided by average.

Overall, the three benchmarks showed that the CV of capacity-related benchmarks occurs in a range of 0.25 to 0.7. For two classes of benchmarks, the maximum CV is 0.4. For that reason, the MGCC Study Participants found this analysis suggests that reasonable standard for inter-annual variability is a CV of up to 0.4.

5.7.1 FINDING: Based on historical load and pricing data, a reasonable level of inter-annual variability is a CV of 0.25 – 0.40.

The historical record for load, net load and energy prices is perhaps the simplest source of comparison data on interannual variability. While future and historical loads will not be exactly comparable due to the increased buildout of solar generation, some trends are likely to remain robust despite changes in the generation mix. Six metrics are presented, all of which reflect annual averages except "Days ANL_T > 32,000" (number of days in which ANL_T exceeded a threshold of 32,000 MW). As shown in Table 6, the CV is only 5-10% for the three load-related metrics. For the other three metrics, the CV ranges from 20-39%.

[43] MGCC Stipulation, pp. 5-6.

Table 6: Annual Average CAISO Loads and PG&E DLAP DA Prices, 2011-2021

Year	Gross Load	Net Load	Max Daily ANL_T	Days ANL_T > 32,000 MW	DA Price	Max Daily DA Price
2011	26,252	25,291	21,275	6	31.20	51.58
2012	26,770	25,472	24,731	29	29.25	45.19
2013	27,309	25,235	24,427	20	42.18	56.78
2014	27,002	24,220	24,562	18	48.94	68.62
2015	26,940	23,758	24,337	24	34.07	51.23
2016	26,699	22,764	22,861	15	29.86	50.03
2017	26,457	21,971	22,685	20	34.56	76.23
2018	25,928	20,868	22,281	16	39.48	79.85
2019	25,252	20,168	21,785	11	37.12	72.20
2020	25,067	19,856	23,089	35	33.42	78.77
2021	25,703	19,111	23,783	26	53.95	103.99
CV	**0.03**	**0.10**	**0.05**	**0.39**	**0.20**	**0.25**

The MGCC Study Participants make several observations regarding these data:

- None of these metrics are equivalent to the annual contribution towards the price of providing long-term capacity resources, but each has its own relevance.
- While GL shows a relatively flat trend, NL trends down, mainly due to expanding renewable generation reducing the NL each year. This downward trend explains the higher CV of NL as compared to GL.
- Despite annual average NL decreasing each year, neither of the ANL_T metrics shows a downward trend.
- Price-related metrics have a somewhat higher inter-annual variability as measured by CV.
- The number of days with very high ANL_T has the highest CV of all the metrics displayed here.

Because capacity costs are driven by extreme events, MGCC Study Participants consider that based on the historical data presented above, a reasonable level of inter-annual variability in the collection of MGCC costs as measured by CV should fall in the upper range of the metrics displayed in Table 6, i.e., 0.25 – 0.40.

5.7.2 FINDING: Based on Resource Adequacy Price Variability, a Reasonable Level of Inter-Annual Variability is a CV of 0.3 to 0.4.

Resource adequacy market prices provide another source of capacity-related historical costs data. However, in comparison to the historical data in Finding 5.7.1, the resource adequacy market represents volatility in prices to meet future, short-term capacity requirements.

The MGCC Study Participants have examined 2012-2021 resource adequacy (RA) market prices from the Energy Division's annual RA Reports.[44] The analysis used the CAISO System Resource Adequacy (System RA) weighted average contract prices ($/kW-month), with all prices converted to real dollars ($2021) using a 2% annual generation inflation rate. Since the 2021 RA report is not yet available, the analysis imputes a 2021 System RA value of $6.88/kW-month using the 2020 RA report price and the difference between the 2020 and 2021 Market Price Benchmark (MPB) System RA Adder from the Energy Division's annual Power Charge Indifference Adjustment (PCIA) MPB True-Up and Forecast filings.[45] The MGCC Study Participants decided to include an imputed 2021 capacity price for consistency with other analyses in this report, and because it is important to consider the 2021 conditions which resulted in a tightening of the capacity market, and a considerable increase in capacity prices and overall price variability.

As shown in Table 7, the CV for System RA market price variability during 2012-2021 is 0.37. Due to the use of an imputed 2021 System RA value, the MGCC Study Participants interpret this result as supporting inter-annual variability with a CV of 0.3 to 0.4.

Table 7: System Resource Adequacy Price Variability

Year	Monthly System RA Price
2012	3.47
2013	3.35
2014	(missing)
2015	2.76
2016	2.69
2017	2.26
2018	2.93
2019	3.60
2020	4.85
2021	6.88
Average	***5.25***
CV	**0.37**

5.7.3 Finding: SERVM Model Outputs Show Inter-Annual Variability With a CV of 0.3 to 0.7.

While MGCC Study Participants did not use hourly SERVM forecast data for rate design purposes, *annual* SERVM forecast data do provide another useful benchmark for inter-annual variability of reliability metrics. The limitations on use of hourly reliability metrics discussed in Section 4.2.2 are less impactful when considering annual aggregations or averages of the data.

44 See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage.

45 The difference between the 2020 and 2021 System RA MPB is $2.13/kW-month. The analysis adds this $2.13/kW-month to the 2020 price from the RA report ($4.75/kW-month) to yield an imputed 2021 System RA price of $6.88/kW-month. This value is close to the unadjusted 2021 System RA MPB of $7.33/kW-month from the 2021 PCIA MPB True-Up and Forecast filing.

As discussed in Section 4.2.3, the MGCC Study Participants identified four reliability metrics that could comprise a potential Grid Stress Metric, including EUE, DR, Upward Reserve Shortfall, and Non-Spin Reserve Shortfall. However, the data required to calculate Upward Reserve Shortfall are not included in the annual aggregation of SERVM forecast data. Thus, for this analysis, only three reliability metrics are used to provide an indication of CV values for grid stress using selected cases from the SERVM forecast data for 2022 and 2026.[46]

The SERVM case data for 2022 and 2026 in Table 8 shows that the CV for the three reliability metrics can vary from 0.27 to 2.63. These findings are based on a simplified 20-case dataset for each forecast year, with each case reflecting a different "weather year" of load.

Table 8: Reliability Metrics in 2022 and 2026 SERVM Forecast Data

	Demand Response	Non-Spin Reserve Shortfall	EUE
2022 Forecast (20 low-load cases)			
Annual Average (MWh)	*8,450*	*29,590*	*81*
CV	**0.27**	**0.45**	**1.76**
2026 Forecast (20 mid-load cases)			
Annual Average (MWh)	2,038	4,726	116
CV	**0.70**	**0.63**	**2.63**

As expected, the most severe form of grid stress (EUE, representing Stage 3 emergencies or rolling outages) shows the smallest average MWh per year and the greatest volatility—many of the 20 cases in each forecast had no EUE. Grid stress represented by DR and Non-Spin Reserves were much more frequent and had greater average annual MWh, while showing less variation year-to-year. However, even for these milder forms of grid stress, SERVM modeling indicates that coefficients of variation in the range of 0.3 to 0.7 occur.

The CV for the three reliability metrics shown in Table 8 may not represent the full variability of annual costs, since each of the 20 cases selected in each run represents an average over 50 iterations, as explained in Section 4.2.1. SERVM runs creates random generator and transmission outages within each of 50 SERVM iterations; averaging over those iterations removes the variability among the 50 iterations. Nonetheless, the remaining variability among the cases provides a useful measure of potential inter-annual variability that is focused on the generation resources and loads that the Commission's Energy Division anticipates will be in place for 2022 and 2026.

46 The full 100-case dataset was not used because each dataset includes five 20-case runs with varying customer load forecast levels – variation in reliability metrics across these varying levels would measure load variability, not inter-annual variability. Since the 2022 dataset provided by the Energy Division is a high-load scenario, the low-load cases for the 2022 dataset were selected for comparison. For the 2026 dataset, the mid-load cases were selected.

5.8 *FINDING: Flex Alerts Provide the Best DA Indication of Grid Stress Conditions That Are Not Well Captured by a Net Load Metric.*

The MGCC Study Participants determined that a price signal triggered by *actual* DA Flex Alert is the best indicator of grid stress conditions that are not well captured by the ANL_T metric. Other candidates for the non-ANL_T indicators of grid stress included DA RMO and Alerts. Along with Flex Alert events, these are the only CAISO events that are consistently called on a DA basis.

Flex Alerts already have significant public exposure, so relying on those events will enhance RTP customer engagement with the program on precisely the days when that engagement is most useful. Furthermore, D.21-12-015 explicitly links the Residential ELRP to the Flex Alerts paid media campaign, increasing the relevance of Flex Alerts to load control. While D.21-12-015 also authorizes the CAISO to trigger the ELRP with Alerts, there is no paid media campaign associated with Alerts—and in recent years, the CAISO has issued Alerts and Flex Alerts nearly contemporaneously.

The MGCC Study Participants also considered using RMO events to trigger a DA price signal. One advantage of using RMO events is that RMO events would add relatively less inter-annual variability than Flex Alerts (see Table 10 in Section 6.1.4). However, relying on RMO events for an event-triggered price signal raises the following concerns.

- While RMOs do indicate grid stress conditions, they reflect generation rather than load. In contrast, Flex Alerts are demand-oriented events that the CAISO calls when it wants customers to reduce consumption to reduce the probability of demand outstripping supply.
- Almost no customers are familiar with RMOs or understand how they should apply to their behavior or operations.
- The RMO signal would need to be restricted to peak and near-peak hours as described in Section 4.1.3, further adding to potential customer confusion.

It should also be noted that this finding refers to use of the *actual* DA Flex Alerts for triggering an adder in the MGCC pricing formula. For purposes of analysis using historical data, the MGCC Study Participants used the combined FA/A data in almost every instance, as explained in Section 4.1.3.

5.9 *SUMMARY: Conceptual Model of Grid Stress and Reliability Events*

Taking into consideration the findings above, the MGCC Study Participants formulated the following simple conceptual model of grid stress and reliability events.

- Low ANL_T days have a low, but non-zero, probability of AWEs, because, as discussed previously, other factors affect system reliability. On these days, a net load measure is a poor predictor of grid stress and reliability.
- High ANL_T days have a high probability of AWEs, but not a 100% probability. Other factors affect system reliability. Furthermore, peak ANL_T levels vary from year to year due to variations in weather, economic conditions, and resource development.

This conceptual model supports using a formula that calculates much of the DAHRTP price from the value of ANL_T, with the remainder captured by a Flex Alert "adder."

6 Development of the Recommended MGCC Pricing Formula

The MGCC component of the DAHRTP rate formula will allocate MGCC marginal cost revenues to the various hours in the year. For most hours of the year, it is reasonable that the MGCC value would be zero or virtually zero because the intent is to allocate the MGCC component to those relatively small number of hours in which grid stress and reliability impacts occur, affecting the marginal generation capacity requirement.

Reflecting the conceptual model in Section 5.9, the MGCC Study Participants conducted further research to design the functional form of the equation depending on ANL_T and Flex Alert events, as shown in Equation 2. The largest portion of MGCC costs should be recovered through a function that depends on ANL_T, whose maximum value is expected to be 100%, based on a logistical regression of RMO events as described below in Section 6.1. The remaining MGCC costs should be recovered through a binary variable (value of 0 or 1) representing whether or not the CAISO calls a DA Flex Alert. The hourly price is determined using the variables H (hourly) and E (event), which are optimized to recover the total MGCC in an average year.

Equation 2: Conceptual Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price} = H * f(ANL_T) + E * \text{Flex Alert}$$

In Finding 5.4, the MGCC Study Participants found that ANL_T best captures grid stress and reliability impacts on an hourly basis during hours with a high probability of such impacts. In Finding 5.7, the Participants found that Flex Alerts provide the best DA indication of grid stress conditions that are not well captured by the ANL_T metric. Thus, when the likelihood of grid impacts is relatively low, an allocation based on a combination of ANL_T (as shown in Figure 5) and a Flex Alert event adder will result in a low MGCC price. However, if the CAISO has declared a DA Flex Alert event based on an expectation of grid stress or reliability issues, then even if forecast ANL_T is low, there should be a significant MGCC price component. At higher net loads, the ANL_T-based capacity price component will be more significant even when the CAISO has not called a Flex Alert event. A combination of a high ANL_T and a Flex Alert event declaration will result in the highest capacity price.

The development and explanation for the recommended price formula is set forth in the following sections.

6.1 Probability of AWEs by Load Level Using a Logistic Regression Analysis

To develop the function $f(ANL_T)$, the MGCC Study Participants recognized that the relationship between the probability of AWE events and ANL_T, as shown in Figure 5, shows classic sigmoidal (S-curve) shapes, with accelerating probabilities at low net load and flattening probabilities at extremely high net load. To model the probability of each type of AWE event occurring as a function of ANL_T, the MGCC Study Participants used a logistic regression method to generate a sigmoidal curve that most closely represents historical data. The results of the logistic regressions are sigmoidal versions of the PCAF function (PCAF-S). A suitable formula for the fitted probability function is a logistic function, where A and B are adjustable coefficients, with B always positive, as shown in Equation 3.

Equation 3: PCAF-S Logistic Probability Function

$$\text{PCAF-S}(ANL_T) = 1 / (1 + \exp(A - B^* ANL_T))$$
$$\text{PCAF-S}(ANL_T < L) = 0$$

At low ANL_T the function looks like a quadratic curve, while at high ANL_T it approaches 1. The function is set to zero when the ANL_T is lower than the 90^{th} percentile (L, or limit) to avoid applying (extremely small) capacity costs at low or moderate net loads.[47]

In the logistic regression, ANL_T is normalized to range from 0 to 1. The coefficients A and B are chosen to minimize a "loss function" which penalizes both false positives (when the probability curve is greater than zero and there was no AWE), and also false negatives (when the probability curve is less than one and there was an AWE), as shown in Equation 4.

Equation 4: Loss Function for Logistic Regression

$$Loss\ Function\ = -\sum_{i=1}^{N} y_i * \log\left(p(y_i)\right) + (1 - y_i) * \log\left(1 - p(y_i)\right)$$

Here y_i is a binary variable which is 1 if there was an AWE in hour i and zero otherwise, and $p(y_i)$ is the modeled probability at hour i using the formula above and the adjusted net load in hour i.

6.1.1 Fitting the PCAF-S Logistic Probability Function

The PCAF-S logistic function was fitted to each of the three types of AWEs—in order of decreasing severity, W/E, FA/A and RMOs.[48] The fitting considered only the most recent five years of available data (2017-2021), rather than the 2012-2021 dataset used in Figure 5, for the following three reasons.

1. Prior to 2017, as solar generation was increasing rapidly, the timing of the net peak was shifting later in the day. While solar generation continued to increase through 2021, the timing of the net peak and associated reliability impacts have stabilized both because the pace of utility-scale solar installations slowed after 2017 and because the shift is constrained by when the sun sets.
2. Climate change is continuing to accelerate, which affects load variability, occurrence of extreme weather conditions such as heat waves, and wildfires (which in turn can affect transmission and generation availability). Earlier years correspond to somewhat different climate conditions than more recent periods.

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47 The 90th percentile net load occurs at approximately 60% of the average annual maximum, which is well below PG&E's original proposed PCAF threshold of 80% of average annual maximum load. A.20-10-011, Exhibit PG&E-1, Ch. 2, p. 2-3.

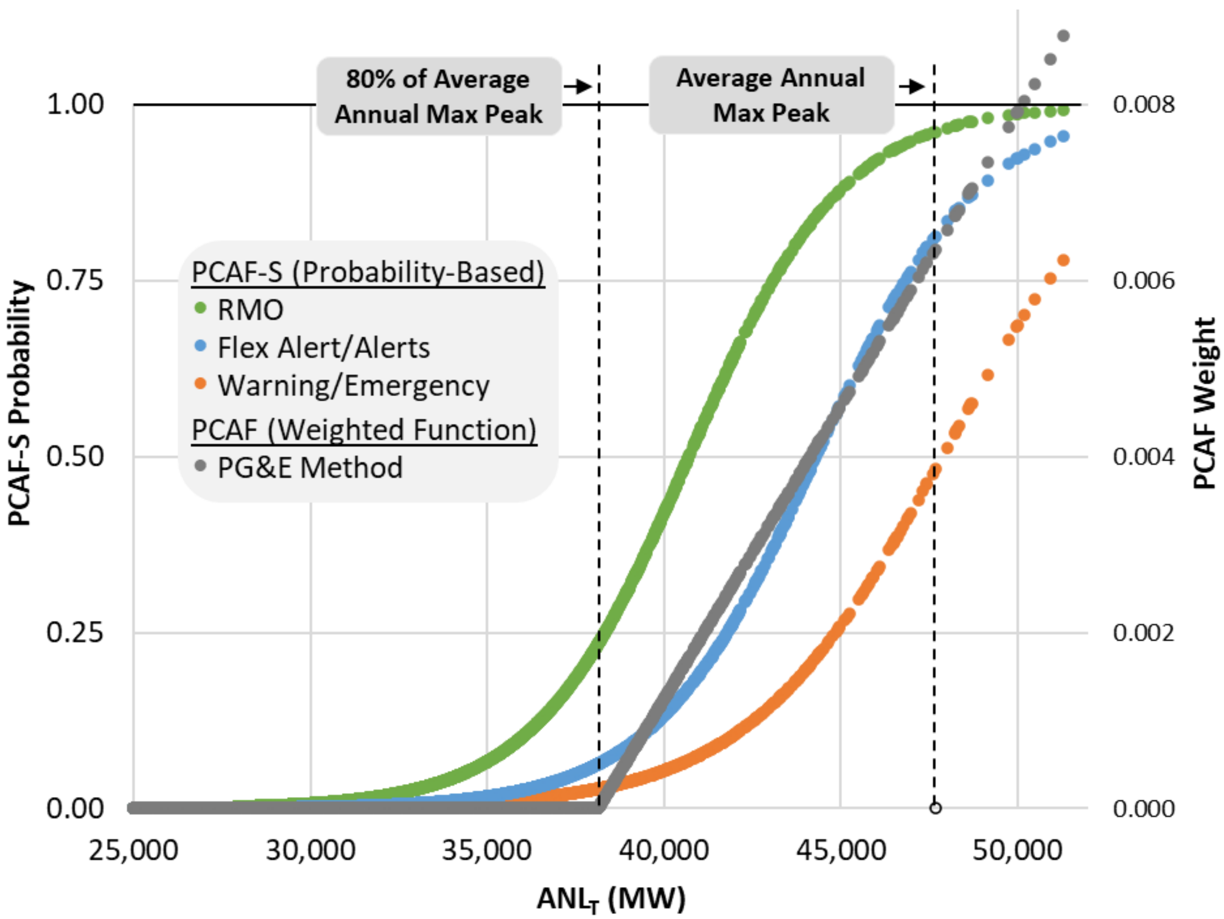
48 As explained in Section 4.1.3, the RMO data were limited to the hours of 3 PM to 10 PM, corresponding to the vast majority of hours covered by W/E and DA FA/A events.

3. The CAISO has indicated that it frequently updates its proprietary procedures for calling AWEs, so the earlier AWEs called prior to 2017 may have been based on materially different criteria than those in use today.

Furthermore, the MGCC Study Participants confirmed that this decision was reasonable by comparing the logistic regressions using the more recent data (2017-2021) with similar analysis of the full dataset (2010-2021). Use of the more recent data (2017-2021) resulted in logistic regressions with better fits to actual AWEs (i.e., smaller loss functions).

The logistic regressions for the three alternative PCAF-S functions yielded the probability-based curves shown in Figure 8. For comparison purposes, the original PCAF method proposed by PG&E (which weights MGCC costs beginning at 80% of the average of annual maximums of ANL_T) is shown—but using a different y-axis on the right since PCAF weights are deterministic allocation factors rather than probabilities and increase without limit as the adjusted net load increases.

Figure 8: Alternative Functions f(ANL_T) for MGCC Pricing Formula,
Applied to Net Load for 2017-2021



6.1.2 Measuring the Performance of Logistic Regression Models

Given the desired alignment of the MGCC hourly allocation with the CAISO's operational grid stress events, the MGCC Study Participants recognized a need for a means to check the effectiveness of the model in distinguishing between events (AWE=1) and non-events (AWE=0). The MGCC Study

Participants chose a widely used performance metric[49] called the "Kolmogorov-Smirnov" (KS) statistic[50] which measures the maximum difference between the distribution of cumulative events and cumulative non-events and ranges between 0% and 100%.[51] The higher the KS Statistic, the better the discriminatory power of the model.

Using the ANL_T as the only independent variable in the logistic regression to predict RMO events gives a KS Statistic of 92% suggesting a strong ability of this model to distinguish between RMO events and non-events.

6.1.3 Allocation of MGCC by ANL_T for Alternative PCAF-S Functions

The total MGCC could be allocated on an hourly basis using any of the ANL_T functions shown in Figure 8, or even a combination of them. The choice of the function impacts both the maximum capacity cost and the expected inter-annual variability likely to be realized during the pilot.

To illustrate how the functions differ in driving the maximum capacity cost, Figure 9 shows the same four curves as in Figure 8 but scaled so that the total capacity cost over the period 2017-2021 is the same for each curve. Each curve is normalized so that the average annual MGCC (2017-2021) equals the annualized value of $90.35, as decided in D.21-11-016 (see Section 3). MECs (DA prices at PG&E DLAP plus primary voltage losses of 1.9%) are also illustrated in the red dots for comparison. The total generation rate is the sum of the MEC, MGCC, and RNA (not shown) in a given hour.

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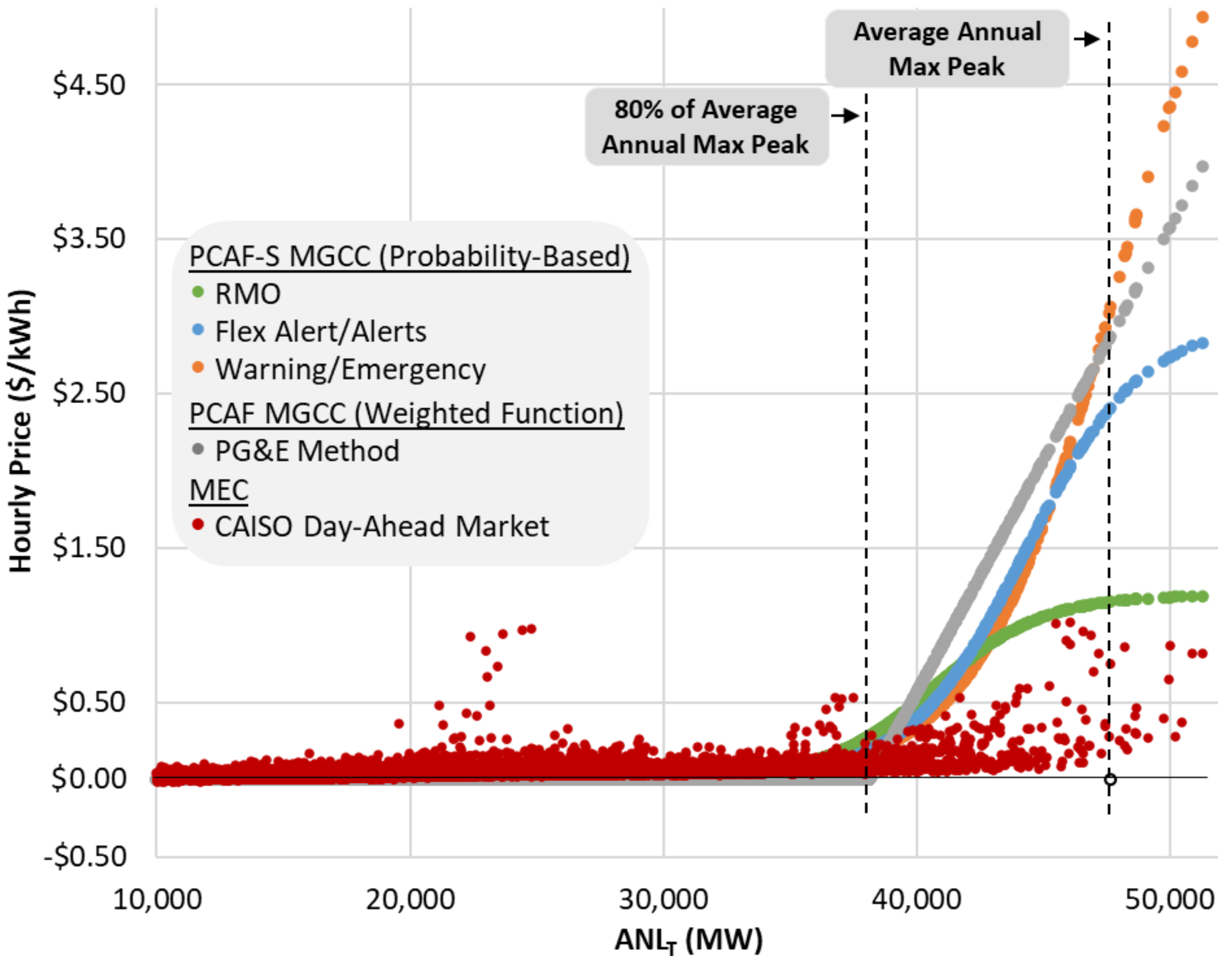
49 For example, the KS Statistic is used in credit risk modeling. Federal Reserve Board, "The Kolmogorov-Smirnov and Divergence Statistics," Report to the Congress on Credit Scoring and Its Effects on the Availability and Affordability of Credit, https://www.federalreserve.gov/boarddocs/rptcongress/creditscore/general.htm.

50 Kolmogorov-Smirnov Goodness of Fit Test, National Institute of Standards and Technology, https://itl.nist.gov/div898/software/dataplot/refman1/auxillar/kstest.htm.

51 Using the logistic regression model, each hourly record is scored with a probability of event (AWE). The KS Statistic is then calculated as follows:

1. The complete dataset is arranged in decreasing order of predicted event probability and then divided into a finite number of groups, e.g. 20 groups.
2. For each group, the cumulative percent of events and non-events is calculated along with the difference between these two cumulative percentages.
3. The KS Statistic is the maximum difference between the cumulative percent of events and non-events.

Figure 9: MGCC Pricing Formula Alternatives, with MEC Prices (for comparison),
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



The MGCC Study Participants note the following observations in response to Figure 9.

- MECs never got above $1.00/kWh, or $1000/MWh, because CAISO DA prices were capped at $1000/MWh during this period. Going forward, CAISO will allow DA energy prices to reach $2000/MWh under certain circumstances.
- The high MECs at ANL$_T$ between 20,000 MW and 25,000 MW all correspond to the February 2021 Texas freeze, which caused natural gas prices paid by electric generators in the CAISO market to escalate dramatically. While there were no capacity issues in California during that event, the very high natural gas prices caused very high wholesale electricity prices (still well below the cap of $9000/MWh in place in Texas at that time).
- The density of points (per MW on the x-axis) is much less at very high ANL$_T$, as indicated by the gaps (dotted portion) in the four curves. There were only five hours during 2017-2021 in which the ANL$_T$ was at or above 50,000 MW (all in 2020).
- The "area under the curve" looks like it is lowest for the RMO PCAF-S function (green) and greatest for the W/E PCAF-S function (orange). However, the density of load points is much

greater at low to moderate ANL_T, so there are many more hours being assigned capacity costs at the lower portion of the RMO PCAF-S function than at the higher portion of the W/E PCAF-S function. Even though the "area under the curve" looks lowest for the RMO PCAF-S, the four MGCC pricing formula alternatives are identically scaled to result in the same annualized capacity price signal ($/kW-yr). Each alternative distributes the MGCC cost differently among hours—both within and between years.

- Since the RMO PCAF-S function has the greatest probability at low to moderate ANL_T (where most of the points are, as shown in Figure 8), its maximum price is the lowest (slightly above $1.00/kWh, as shown in Figure 9). (Again, the total MGCC is the same for each of the four alternatives.) The PCAF method function takes effect at the highest ANL_T value and has the second-highest maximum price of approximately $4/kWh (as shown in Figure 9).[52] The W/E PCAF-S function actually has some weight below the PCAF threshold, but for most of its range it has the lowest weight. Then, at the highest levels of ANL_T, the maximum price for the W/E PCAF-S function reaches approximately $5/kWh (as shown in Figure 9). Overall, the W/E PCAF-S function has the highest maximum price of the three probability-based alternatives. The FA/A PCAF-S function is in the middle.
- Because almost all extremely-high ANL_T hours corresponded to an actual RMO event, the RMO PCAF-S function in Figure 8 reaches almost 1 within the scale of the figure, and likewise its corresponding MGCC pricing in Figure 8 flattens out at the highest ANL_T values observed in 2017-2021. While the FA/A PCAF-S function is visibly flattening at those levels, it is not as close to its maximum.
- In contrast, the W/E PCAF-S function is only getting slightly less steep at the highest ANL_T, and could increase toward its maximum of approximately $6.40/kWh if higher ANL_T were to occur. Similarly, the PCAF curve would continue to increase without limit at ANL_T above the 2017-2021 historical maximum. Such high price levels, coupled with these two functions' lower prices at lower load levels (compared to the RMO function), dramatically increase the inter-annual volatility of capacity-related revenue collection (see Section 6.1.4).

If a combined alternative were selected, applying more weight to the W/E PCAF-S or PCAF functions would risk more extreme capacity costs at high ANL_T, and would diminish the price signal at lower ANL_T. As discussed in the following section, this turns out to have implications for inter-annual revenue variability.

6.1.4 Inter-Annual Revenue Variability for Alternative PCAF-S Functions and Flex Alert Pricing

To get a sense for the inter-annual revenue variability associated with potential elements in the MGCC function, the annual capacity cost for a flat load (i.e., not considering load shape) was calculated for each of the three alternative PCAF-S functions described above. The same calculations were performed for the original PCAF function from PG&E's testimony and a hypothetical Flex Alert event-only MGCC

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52 Note that the PCAF threshold was calculated using only the maximum annual net loads from 2017-2021; using 2014-2021 or 2012-2021 maximum annual net loads the PCAF threshold would have been lower, and the maximum PCAF price would also have been lower.

price.[53] Each of the MGCC elements was scaled so that the annual MGCC over 2017-2021 averaged $90.35/kW-yr.

The MGCC-only results for each alternative PCAF-S function, the original PCAF function, and as the Flex Alert are shown in Table 9. Table 10 shows the same statistics for total generation cost (MEC plus MGCC). For comparison between these and other measures of inter-annual variability, the CV is calculated as the standard deviation divided by average, as discussed in Finding 5.7.

Table 9: Annual Total Capacity Cost for Candidate MGCC Rate Elements, 2017-2021 ($/kW-year)

Year	**PCAF** PG&E Method	**PCAF-S Alternatives** Probability-Based			**Event Adders**	
		W/E	**Flex**	**RMO**	**Flex**	**RMO**
2017	$ 141.05	$ 131.73	$ 134.62	$ 128.70	$ 90.35	$ 131.42
2018	77.55	77.40	80.95	84.82	23.32	41.07
2019	26.56	35.81	38.90	53.11	17.49	16.43
2020	169.59	163.26	150.42	125.39	209.85	139.63
2021	37.00	43.55	46.86	59.72	110.75	123.20
Average	90.35	90.35	90.35	90.35	90.35	90.35
Annual Max/Min Ratio[a]	*6.39*	*4.56*	*3.87*	*2.42*	*12.00*	*8.50*
CV	*0.62*	*0.55*	*0.50*	*0.35*	*0.77*	*0.57*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

53 As discussed in Finding 5.8, the MGCC Study Participants also considered using RMO events to trigger a day-ahead price signal. As shown in Table 10, an advantage an RMO event trigger is relatively less inter-annual variability than a Flex Alert event trigger. For reasons explained in Finding 5.8, the Participants determined that a Flex Alert event trigger provides the best day-ahead indication of grid stress conditions that are not well captured by a net load metric.

Table 10: Annual Total Generation Cost for MGCC Rate Elements, 2017-2021
Including MECs and MGCCs (from Table 9), Applied to Net Load and CAISO Day-Ahead Energy Prices

Year	MEC CAISO Market	Total Generation Cost = MEC + MGCC					
		PCAF PG&E Method	PCAF-S Alternatives Probability-Based			Event Adders	
			W/E	Flex	RMO	Flex	RMO
2017	$ 308.46	$ 449.51	$ 440.19	$ 443.08	$ 437.17	$ 398.81	$ 439.88
2018	352.35	429.90	429.75	433.30	437.17	375.67	393.42
2019	331.28	357.83	367.09	370.18	384.39	348.76	347.70
2020	299.06	468.65	462.32	449.48	424.45	508.91	438.69
2021	481.46	518.45	525.01	528.32	541.17	592.21	604.66
Average	354.52	444.87	444.87	444.87	444.87	444.87	444.87
Annual Max/Min Ratio[a]	*1.61*	*1.45*	*1.43*	*1.43*	*1.41*	*1.70*	*1.74*
CV	*0.19*	*0.12*	*0.11*	*0.11*	*0.12*	*0.21*	*0.20*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

The MGCC Study Participants note the following observations in response to Table 9 and Table 10.

- Compared to the probability-based functions, if the entire MGCC price were assigned based on Flex Alert events, there would be more variability year-to-year. A Flex Alert event-only price would also have the highest ratio between the largest and smallest annual MGCC totals, whether considered in isolation or combined with MECs. This result confirmed the MGCC Study Participants' decision to use a PCAF-S function for the majority of the capacity price signal, with the Flex Alert event component providing a minority of the signal.
- Among the original PCAF and the three PCAF-S functions, the RMO-based PCAF-S function has the lowest interannual variability when considering the MGCC cost only (Table 9). The PCAF and the W/E PCAF-S functions have the highest variability, with the FA/A PCAF-S function in between.
- However, when MECs are added (in Table 10), the PCAF-S functions and the original PCAF method yield almost identical CV and annual max/min ratios. This is because 2021, which thankfully had lower maximum loads than 2020, had significantly higher gas prices and therefore higher energy prices, which tended to even out the options. Because this combination of lower loads and higher gas prices may not be typical, it seems unlikely that MECs would even out the inter-annual variability over the long run.

Based on the results shown in Table 9, the MGCC Study Participants found that the RMO probability-based PCAF-S function is the only alternative that meets the inter-annual variability standard of a CV less than 0.4, as discussed in Finding 5.7. Furthermore, the recommended PCAF-S function exhibits max/min ratio of annual capacity costs of 2.4, far lower than any of the other alternatives.

6.1.5 Selection of the RMO Probability-Based Function as the Recommended PCAF-S Function

The MGCC Study Participants selected the RMO probability-based function as the recommended PCAF-S function for the following reasons.

- **Lowest maximum price:** The RMO probability-based function has the lowest maximum price over the 2017-2021 period, whether considered alone ($1.19/kWh) or in combination with MECs ($2.12/kWh). MGCC Study Participants are concerned that the potential for extremely high generation prices could scare off potential customers – the combined prices of $4.78/kWh, $3.65/kWh and $5.76/kWh for PCAF-based, FA/A-based and W/E-based rate elements, respectively, are high enough to cause comparisons to prices in Texas during the 2021 freeze event. While those prices occurred for only one hour (in 2020) rather than the multiple days in Texas, "perception is reality" when it comes to customer willingness to sign on to a pilot rate. MGCC Study Participants believe that using the PCAF-based, FA/A or W/E curves would necessitate instituting a price cap on the capacity cost or combined generation cost rate, which would complicate implementation of the rate.
- **Encourages preventative behavior:** The RMO probability-based function increases prices at lower load levels than the alternatives. This will provide a preventative and proactive signal that will increase prices at somewhat lower load levels, encouraging participants to practice behaviors that will help prevent extreme W/E events.
- **Avoids inter-annual variability in revenue collection:** As discussed in Section 6.1.4, the RMO probability-based curve is likely to result in significantly less inter-annual variability in MGCC revenue collection than the alternatives. While inter-annual variability is similar for all the probability-based curves when total generation costs (including MECs) are considered (see Table 10), there is not a significant risk that MEC collections will differ much from costs since hourly MECs represent actual marginal costs. It is expected that a significant advantage of the DAHRTP rate is that energy costs will require little, if any, true-up.

  In contrast, all of the hourly MGCC rate elements represent possible approximations to the true marginal capacity costs, which MGCC Study Participants consider to be ill-defined, or at least only calculable after the fact. The MGCC revenue requirement is set in each rate case and must be collected. Reducing the interannual variability of the MGCC component of the rate will reduce the likelihood and magnitude of revenue under-collections and cost shifting.

Table 11 shows the annual MGCC, the maximum capacity price over 2017-2021, and various annual summary statistics for three alternative combinations of MGCC rate elements, as follows.

- PG&E's original proposed PCAF method
- PCAF-S based on W/E events, plus adders for actual RMOs and Flex Alert events
- Recommended PCAF-S based on RMO events, plus an adder for Flex Alert events

Table 11: Annual Costs for Alternative MGCC Pricing Formulas, 2017-2021
Applied to Net Load and CAISO Day-Ahead Energy Prices

Year	MEC CAISO Market	Alternative MGCC Pricing Formulas		
		PCAF PG&E Method	**PCAF-S W/E + RMO & Flex Alert Adders**	Recommended **PCAF-S RMO + Flex Alert Adder**
2017	$ 308.46	$ 141.05	$ 121.00	$ 125.41
2018	352.35	77.55	53.70	79.55
2019	331.28	26.56	25.88	50.06
2020	299.06	169.59	168.89	132.64
2021	481.46	37.00	82.29	64.09
Average	354.52	90.35	90.35	90.35
Annual Max/Min Ratio[a]	*1.61*	*6.39*	*6.53*	*2.65*
CV	*0.19*	0.62	*0.56*	*0.37*

(a) The annual max/min ratio is the ratio of the maximum and minimum values for 2017-2021.

The final form of the recommended MGCC pricing formula is summarized in the next section.

6.2 Recommended MGCC Pricing Formula

As discussed above, the MGCC Study Participants determined that the largest portion of MGCC costs should be recovered through a PCAF-S function that depends on ANL_T, whose maximum value is expected to be 100%, based on a logistical regression of RMO events. The remaining MGCC costs should be recovered through a binary variable (value of 0 or 1) representing whether or not the CAISO calls a DA Flex Alert. As explained at the beginning of Section 3, the hourly price is determined using the variables H (hourly) and E (event) in Equation 2, which are selected to recover the total MGCC in an average year.

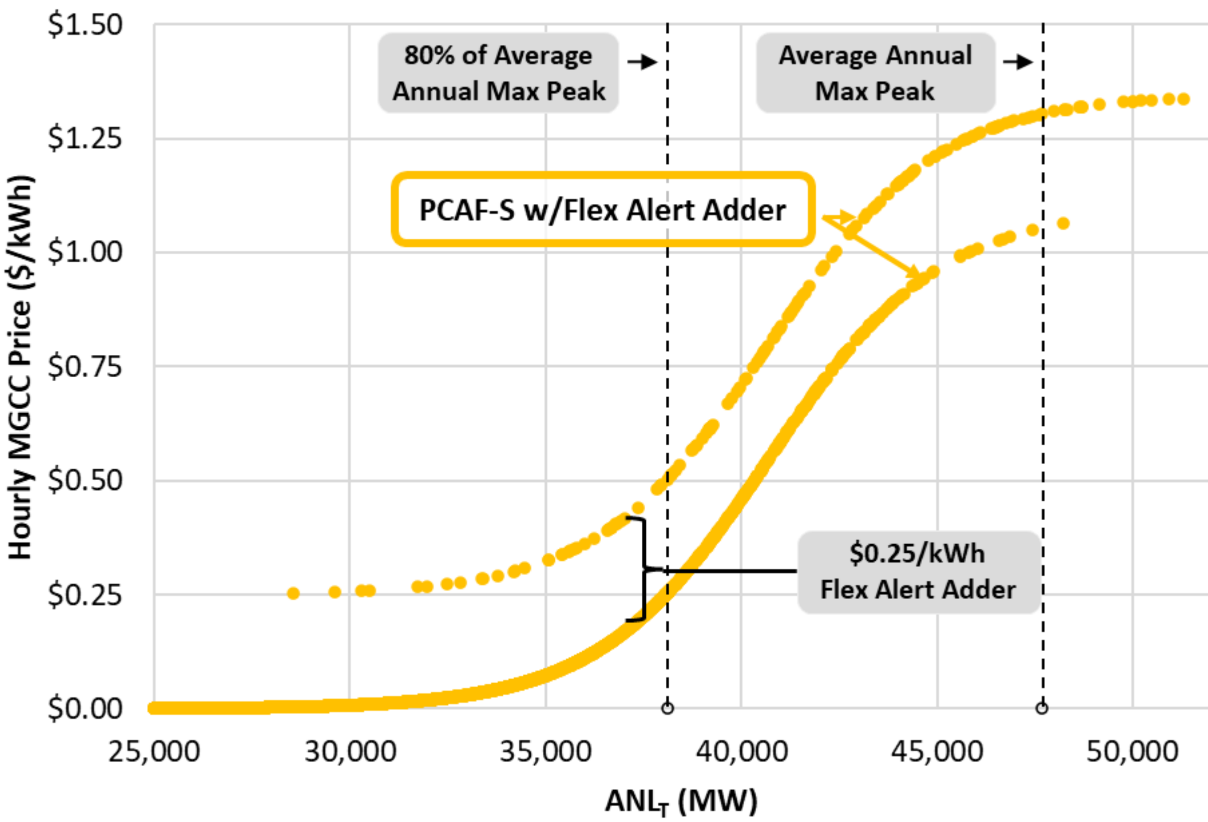
In Finding 5.7, the MGCC Study Participants explain why Flex Alerts provide the best DA indication of grid stress conditions that are not well captured by the ANL_T metric. In order to determine what price signal triggered by *actual* DA Flex Alert events should be added to the PCAF-S function, the MGCC Study Participants relied upon the $250/MWh penalty price for ancillary services shortages in CAISO (see Section 4.2.3). Thus, the participant consensus is to include a $0.25/kWh adder for DA Flex Alert hours in the MGCC price signal.

The recommended Hourly MGCC Pricing Formula, Equation 5, is illustrated in Figure 10. The specific values for H, A, and B may be updated by PG&E prior to program launch, reflecting additional historical data or any updates to the MGCC price of $90.35/kW-year. The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

Equation 5: Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price: PCAF-S}(ANL_T) = H / (1 + \exp(A - B^* ANL_T)) + E * \text{Flex Alert}$$
$$\text{PCAF-S}(ANL_T < L) = 0$$
ANL_T is normalized[54]
$$E = \$0.25$$
$$H = \$1.097$$
$$A = 18.78$$
$$B = 23.72$$
$$L = 27{,}713 \text{ MW}$$

Figure 10: Hourly MGCC Pricing Formula
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



54 ANL_T is normalized using the formula: $(ANL_T - Min)/(Max - Min)$, where Min/Max are the minimum/maximum ANL_T values in the dataset.

As an example of applying Equation 5, during CAISO Flex Alert hours the recommended MGCC rate design would send an average total generation price signal of $1.11/kWh, which is a strong price signal for customers to conserve or shift usage.[55] The recommended MGCC rate design would include the following components:

- **PCAF-S price**: Would have averaged almost $0.62/kWh during FA/A events from 2017-2021
- **Flex Alert adder:** $0.25/kWh
- **Hourly MEC costs:** Averaged $0.24/kWh during FA/A events from 2017-2021

In addition, the RNA will vary by rate and TOU period, potentially providing a complementary increase to the generation price signal during CAISO Flex Alert hours.

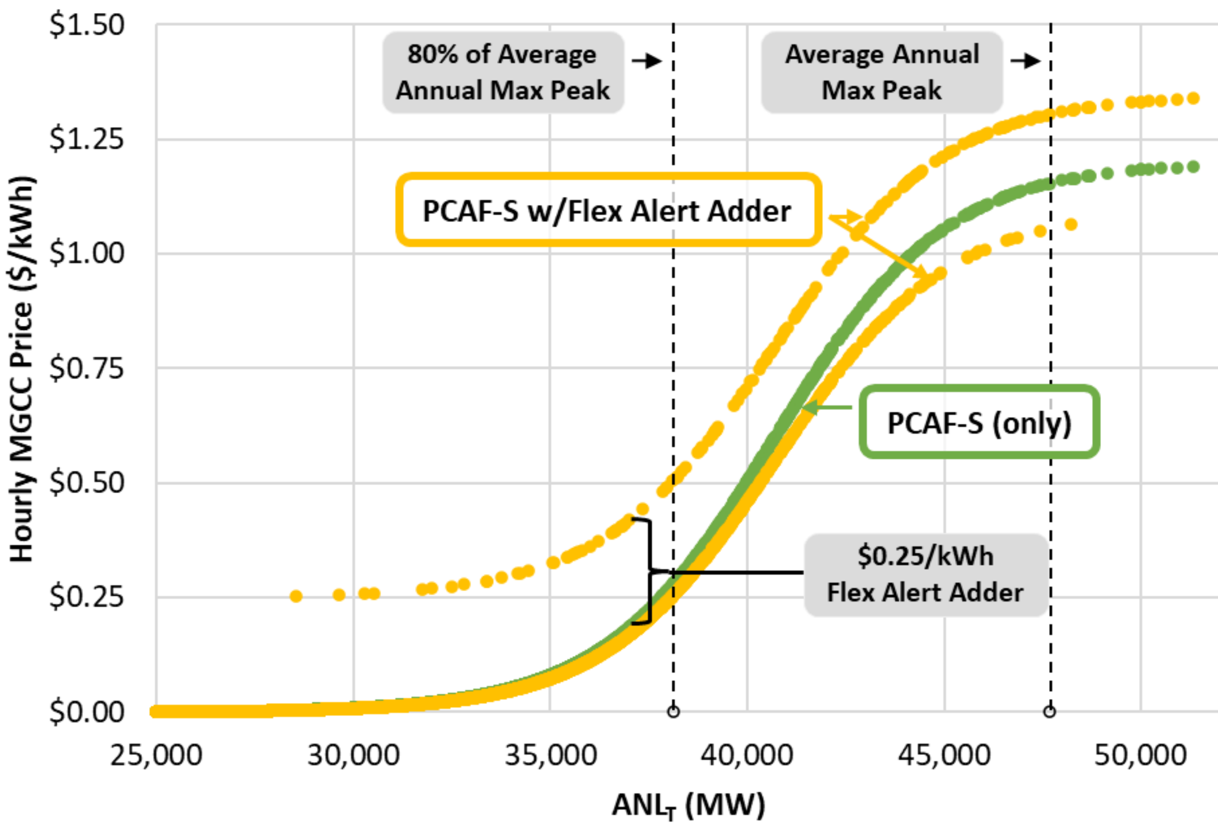
The effect of the Flex Alert adder is illustrated in Figure 11, which contrasts a PCAF-S function that collects the full MGCC cost with the recommended combination of a PCAF-S function with a Flex Alert adder for all hours in 2017-2021. The PCAF-S function that collects the full MGCC cost is shown in green, and is the same function illustrated in green in in Figure 8 and Figure 9. The recommended PCAF-S function with a Flex Alert adder is shown as a yellow curve—which appears in two parts because the upper part of the curve indicates hours in which a Flex Alert was called, and the lower part of the curve represents hours without a Flex Alert.

The distance between the two parts of the yellow curve in Figure 11 is exactly $0.25/kWh—the amount of the Flex Alert adder. The green curve separates from the lower part of the yellow curve because in order to collect the same total MGCC value, the variable H in Equation 5 for a formula with no Flex Alert adder (the green curve) is determined to be $1.2/kWh, rather than $1.097/kWh for the recommended formula (the yellow curve).

Note that the Flex Alert adders are rare at lower loads, but do occur during some hours with ANL_T below 30,000 MW. Flex Alerts become more frequent at very high net loads, and applied to all but one of the hours in which the ANL_T exceeded the average annual maximum over 2017-2021. Thus, the proposed final MGCC pricing formula provides a stronger signal than the RMO-based PCAF-S function alone at extremely high net load, without becoming excessive. The proposed MGCC function also provides a noticeable signal at low net load levels whenever there is a (well-advertised) Flex Alert.

55 This is higher than the $0.285/kWh summer peak generation price for proposed B-6 rates plus $0.60/kWh price adder in PG&E’s commercial CPP program. Also, because the RTP price has an hourly shape (concentrating on the hours with the greatest forecasted grid stress) whereas the B-6 rate and its CPP adder are the same for each hour in an event, the maximum generation price under RTP is even higher than $1.11/kWh (see Figure 11, below).

Figure 11: Hourly MGCC Pricing Formula Compared to RMO Probability-Based PCAF-S Function
Applied to Net Load and CAISO Day-Ahead Energy Prices for 2017-2021



To provide additional context, Figure 12 presents the average MGCC in $/MWh by month and HE for the preferred alternative, while Figure 13 presents the same data for MEC. For system conditions in 2017-2021, the MGCC component would have been much more concentrated in the summer peak period (June-September from 4 PM to 9 PM, or HE 17 to 21) than the MEC component. There is some MGCC cost outside the (highlighted) summer peak period, due to high ANL_T or CAISO Flex Alert events.

Figure 12: Average MGCC by Month and Hour Ending for Preferred Alternative in $/MWh, 2017-2021

Month/HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	**0**
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	**0**
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	1	0	0	**0**
6	0	0	0	0	0	0	0	0	0	0	0	0	0	1	6	13	24	37	61	85	73	29	4	0	**14**
7	0	0	0	0	0	0	0	0	0	0	0	0	1	3	8	24	49	78	140	199	151	54	9	1	**30**
8	0	0	0	0	0	0	0	0	0	0	0	0	1	6	24	66	102	150	243	277	213	92	16	2	**50**
9	0	0	0	0	0	0	0	0	0	0	0	0	1	5	12	33	51	83	144	138	91	36	8	1	**25**
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	6	16	23	16	8	4	0	0	**3**
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	**0**
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2	1	0	0	0	**0**
Average	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**4**	**12**	**19**	**31**	**52**	**61**	**45**	**18**	**3**	**0**	**10**

Figure 13: Average MEC by Month and Hour Ending for Preferred Alternative in $/MWh, 2017-2021

Month/HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
1	33	31	31	31	32	36	44	45	37	32	29	27	25	25	27	33	42	55	54	49	45	41	37	35	**36**
2	42	39	38	38	41	50	64	57	41	33	28	26	23	23	24	31	46	73	88	78	70	62	50	45	**46**
3	30	28	27	27	29	37	46	43	32	23	20	17	15	14	15	18	22	35	52	59	51	44	37	33	**31**
4	26	24	23	23	26	33	40	33	23	18	16	14	12	12	13	14	17	25	40	57	53	42	34	29	**27**
5	25	23	21	21	23	30	32	24	18	16	15	14	14	16	17	19	21	27	40	55	57	43	33	28	**26**
6	30	27	26	25	27	30	31	23	19	19	20	22	25	28	30	33	37	42	56	78	61	47	36	32	**34**
7	37	34	33	32	32	35	37	31	27	28	31	33	37	40	44	48	55	64	86	111	75	57	44	40	**45**
8	40	37	36	35	35	38	43	38	31	31	33	36	39	42	46	52	57	72	116	123	74	56	47	42	**50**
9	39	38	36	36	37	40	45	42	33	30	30	32	35	38	41	45	49	64	97	83	60	50	45	42	**45**
10	42	40	38	38	39	44	52	53	42	37	36	35	36	38	40	42	48	76	98	76	60	54	48	44	**48**
11	43	41	40	40	42	49	57	50	41	37	35	34	34	35	38	47	62	85	71	62	57	52	48	45	**48**
12	43	41	40	40	42	47	57	55	46	41	39	36	35	35	38	47	60	76	69	64	60	54	50	45	**48**
Average	**36**	**34**	**32**	**32**	**34**	**39**	**45**	**41**	**32**	**29**	**28**	**27**	**27**	**29**	**31**	**36**	**43**	**58**	**72**	**74**	**60**	**50**	**42**	**38**	**40**

7 BILL IMPACT ANALYSIS FINDINGS

From the customer's perspective, the most important aspect of an RTP rate is likely its impact on their bills. MGCC Study Participants therefore considered both average generation-related bills and their expected volatility, or year-to-year variability. This analysis relies on historical load and market energy price data because, even if suitable hourly forecast data were available, the hourly effects of the Flex Alert event adder cannot be forecast. The most recent five years (2017-2021) were used for this analysis for consistency with the underlying MGCC analysis.

Moreover, while this MGCC Study is intended to inform all of PG&E's RTP rates under consideration (BEV-1 and 2; and B-20, B-6, and E-ELEC under consideration in A.19-11-019), the bill impact analysis considers only Schedule B-6, for the following reasons:

- The Residential E-ELEC rate was just adopted in D.21-11-016 and does not yet have any customer load data, making it impossible to calculate an accurate expected bill under the existing or RTP version of the rate at this time.
- Likewise, the BEV-1 and 2 rates did not exist in 2017, so the first part of the comparison period would need to be filled in with data from other classes. Moreover, commercial EV charging is still relatively new, so there are few customers, but with a variety of very different load shapes for the various use cases (transit, workplace charging, etc.), which can lead to large changes in the class load characteristics from year to year since the class is growing.
- B-20 has demand charges, which complicates bill calculations because class-average loads cannot be used due to their reduced volatility compared to individual customer bills.

Thus, the B-6 rate[56] was chosen as the Otherwise Applicable Tariff (OAT) for this analysis, using its primary voltage parameters (as it is the middle of the three options) as determined by D.21-11-016 included in a recent PD as described in Section 3.

The bill impact analysis also considers the impact of the RNA. The RNA is designed to make the RTP rate revenue-neutral in each TOU period, with two exceptions. The RNA should not be inverted (e.g., the off-peak RNA set higher than the peak RNA) and the RNA value should not drop below the Renewable Energy Certificate (REC) adder, in which case it is set to the REC adder.

The RNA has been recalculated using updated Schedule B-6 OAT rates for the entire 2017-2021 period (instead of just 2017 for the original RNA analysis), as shown in Table 12. PG&E's recalculation was necessary because the updated B-6 rates have a significantly higher differential between peak and off-peak than the B-6 rates in place in March 2020, which were the basis for calculating the (flat) RNA for PG&E's initial RTP testimony. PG&E's updated RNA determination also incorporates the actual MECs

56 Even the B-6 rate has complications – B-6 is a new rate as of 2019 (with a new peak period), whose customers initially came from the A-6 rate but more recently have been drawn from A-1 customers. Thus, even using load shapes from A-6 plus B-6 customers is problematic. To provide a more apples to apples comparison across years, the average load shape by hour was drawn from the approximately 13,000 current B-6 customers who were also customers in 2017 (on a different rate). This relatively stable cohort represents the great majority of current B-6 customers.

for 2017-2021, the proposed MGCC pricing formula, and updated average loads from a stable cohort of customers currently on the B-6 rate. The original RNA had been set to the REC adder in each TOU period; the updated RNA exhibits significant differentiation, which will be advantageous for battery storage economics.

Table 12: Original and Revised RNA for B-6 RTP Rate ($/kWh)

TOU Period	Original RNA	Revised RNA
Summer Peak (Jun-Sep, 4-9 PM)	$ 0.00519	$ 0.05996
Summer Off-Peak (All other hours)	0.00519	0.01486
Winter Peak (Oct-May, 4-9 PM)	0.00519	0.01542
Winter Off-Peak (All other hours)	0.00519	0.00621
Spring Super Off-Peak (Mar-May, 9 AM-2 PM)	0.00519	0.00621

Average customer bills were calculated by multiplying the proposed MGCC, MEC and their sum for each hour in 2017-2021 by the average hourly load per customer in the B-6 cohort.[57] Bills were calculated both before and after the modeled operation of a 5-kW, two-hour-duration battery.[58]

7.1 *Finding: Customers are Unlikely to Experience a Substantial Increase in Inter-Annual Bill Variability After Migrating to a DAHRTP Rate Using the Recommended MGCC Pricing Formula.*

The total bill inter-annual variability of the recommended MGCC pricing formula is almost exactly the same as for the OAT, regardless of whether the prototypical customer has a battery storage device, as shown in Table 13. While customers may see some increase in *monthly* bill variability, particularly in months with high ANL_T and Flex Alert events, it appears unlikely that customers will experience a substantial increase in inter-annual bill variability as a result of migrating from the OAT to a DAHRTP rate.

This somewhat surprising finding is a result of two sources of stability. First, when considering the total bill, a substantial portion of the total bill is not affected by a generation-only DAHRTP rate.

Second, the RNA included in the DAHRTP rate stabilizes the inter-annual variability associated with the recommended MGCC pricing formula, by adding a bill component that varies by TOU period but not by year. As shown in Table 13, the CV for the generation portion of a Schedule B-6 bill using the

57 Data for the last two months of 2021 were not available and were filled in using data from the last two months of 2020. Average loads were calculated by dividing total load by the number of customers in the B-6 cohort for each month.

58 Average load for this pool of customers is approximately 4 kW. Many potential RTP customers are NEM customers whose load is at minimum mid-day and at maximum during the evening peak; the typical customer would likely use a battery targeted to supply about 4 kW. The MGCC Study Participants chose to model a 5 kW, 2-hour battery operation, representing a customer with a single Tesla Powerwall (the most popular unit for BTM batteries) who reserves some of the Powerwall's 2.7-hour duration for resiliency from outages or to increase the battery's longevity by keeping the battery between 15% and 85% state of charge.

recommended PCAF-S formula and a Flex Alert event adder is 0.11, much lower than the 0.4 standard determined in Finding 5.7.

The CV of 0.11 for the total generation portion of the Schedule B-6 bill is roughly equal to the CV for the recommended RMO probability-based PCAF-S function alone. This result indicates that the stability provided by the RNA component of the generation rate happens to offset the somewhat higher inter-annual variability driven by the inclusion of the Flex Alert adder.

7.2 FINDING: A Prototypical Customer is Likely to Experience Similar Average Bills After Migrating to a DAHRTP Rate.

The MGCC Study Participants estimated the average bill for a Schedule B-6 customer using the OAT, recommended and alternative MGCC pricing formulas, and PG&E's original PCAF method. As shown in Table 13, all of the RTP alternatives yield average generation-only and total bills that are almost identical to the OAT over the 2017-2021 period.

For the recommended MGCC alternative this is because the RNA was updated to obtain equal revenue to the OAT, but the other RTP alternatives also almost exactly match the OAT's average bill. With the addition of a battery, the RTP rates yield bills that are approximately 1% lower than the OAT in total bill (and would be approximately 4% lower for the generation portion).

In the high-grid-stress year 2020, customers fare best with the OAT or the recommended MGCC pricing formula in the absence of a battery (or any price-responsive load shifting). Customers with a battery fare best on the recommended MGCC RTP rate.

However, in 2021, customers would fare best with the OAT with or without a battery because MECs were significantly higher than the five-year average. The OAT does not pass through above-average (or below-average) MECs in the same year—but because customers on the OAT are subject to energy cost reconciliation through an annual true-up, those benefits would not be retained.[59]

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59 As part of the DAHRTP pilots, the relationship between the RTP rate and the ERRA balancing account will be examined in the final evaluation report. PG&E GRC2 RTP Track Settlement (Jan. 14 Settlement), Appendix A, Attachment B, "Background and Conceptual Details of PG&E's Generation Revenue Over and Under-Collection Study."

Table 13: Generation-Only and Total Bills for an Average B-6 Customer With and Without 2-hr Battery
Applied to Net Load and CAISO Day-Ahead Energy Prices, 2017-2021.

	OAT			**PCAF** PG&E Method			**PCAF-S W/E + RMO & Flex Alert Adders**			Recommended **PCAF-S RMO + Flex Alert Adder**		
Bill Type:	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery	Generation	Total	Total w/Battery
2017	2,610	9,116	8,821	2,744	9,250	8,747	2,620	9,126	8,727	2,629	9,135	8,712
2018	2,452	8,597	8,302	2,371	8,515	8,143	2,240	8,384	8,093	2,372	8,516	8,167
2019	2,320	8,088	7,793	1,896	7,664	7,417	1,883	7,650	7,443	2,015	7,783	7,496
2020	2,109	7,388	7,093	2,314	7,592	6,976	2,298	7,577	7,060	2,126	7,404	6,934
2021	2,276	7,841	7,547	2,486	8,050	7,708	2,710	8,275	7,898	2,625	8,190	7,803
Average	**2,353**	**8,206**	**7,911**	**2,362**	**8,214**	**7,798**	**2,350**	**8,202**	**7,844**	**2,353**	**8,206**	**7,822**
vs. OAT	**-**	**-**	**-**	**9**	**9**	**(113)**	**(3)**	**(3)**	**(67)**	**0**	**0**	**(89)**
CV	*0.072*	*0.073*	*0.076*	*0.117*	*0.075*	*0.078*	*0.126*	*0.069*	*0.073*	*0.107*	*0.073*	*0.077*

7.3 *FINDING: Profit Opportunities for Battery Storage Systems are Likely to Increase With Use of the Recommended MGCC Pricing Formula.*

PG&E's RTP design rates are expected to both incent battery operation that helps the grid and promote customer adoption of battery storage by providing a greater return on investment for customer-installed batteries than the OAT. The expectation that the combination of the MGCC and MEC rates will incent battery operations and other customer behaviors that help the grid is set out in this study's findings (Section 5) and the process of designing the MGCC pricing formula (Section 6). To investigate the return on investment for customer-installed batteries, the operation of a prototypical battery storage unit was modeled under various versions of the MGCC pricing formula and compared to the OAT.

For simplicity, the battery was assumed to discharge during the two highest-priced hours of the day (considering the entire tariff, not just the generation portion) and charge during the two lowest-priced hours, except that the charging cost was increased by 20% to account for round-trip efficiency losses and battery degradation. On days when the battery would have lost money from this operation, it was assumed to stay idle.

Table 14 shows the annual bill savings, or "profit," in dollars per year for a 5-kW battery discharged at most 2 hours per day, for the OAT, PG&E's original PCAF-based MGCC method, and the two alternative combinations of MGCC rate elements shown in Table 11. As noted in Section 7.2, the combination of a battery and the recommended MGCC RTP rate performs better than the OAT in most but not all conditions reflected in the 2017-2021 period.

Table 14: Battery Savings for Alternative MGCC Pricing Formulas
Applied to Net Load and CAISO Day-Ahead Energy Prices, 2017-2021.

Year	**Battery Value (5-kW, 2-hour)**			
	OAT	**PCAF** PG&E Method	**PCAF-S W/E + RMO & Flex Alert Adders**	**Recommended PCAF-S RMO + Flex Alert Adder**
2017	$ 294	$ 503	$ 399	$ 422
2018	294	371	291	349
2019	294	247	207	287
2020	294	616	517	471
2021	294	342	376	387
Average	**294**	**416**	**358**	**383**
CV	*0.00*	*0.31*	*0.29*	*0.16*

As expected, each MGCC pricing formula alternative provides greater savings for the modeled battery than the OAT. Under the B-6 OAT, the battery savings is approximately 45 cents or less per day during the winter and spring when there is a lower-priced Super Off-Peak period, and approximately $2.00 per day during the summer. Under the two PCAF-S alternatives and PG&E's original PCAF method, battery savings varies from day-to-day, sometimes with no savings opportunity, but savings increase on the highest-priced day to as much as $22/day for the recommended DAHRTP rate (and as much as $47/day for PG&E's original PCAF method) based on 2017-2021 conditions. As a result, the average battery savings for the recommended DAHRTP rate is $383 per year, compared to $294 per year for the Schedule B-6 OAT.

The MGCC Study Participants view these results as confirming their recommendation to adopt an RMO probability-based PCAF-S formula, for the following reasons.

- Even though the original PCAF-based alternative yields the most battery value, it has much greater variation year to year. The PCAF-based alternative results in a 9% increase in battery savings relative to the recommended MGCC pricing formula, while the PCAF method increases volatility (CV) in bill savings to the customer by 94% (CV of 0.31 compared to 0.16).
- The MGCC pricing formula using a W/E probability-based PCAF-S function, an RMO adder, and a Flex Alert adder provides 7% less expected bill savings and a 81% increase in bill savings volatility. Because the RMO and Flex Alert adders generally apply for many hours in a day, the resulting MGCC price is relatively flat over the entire peak period. The battery can only discharge in two of the five peak-period hours, limiting bill savings opportunities during event days.
- The recommended RMO probability-based PCAF-S formula with a Flex Alert adder has a shape that is more responsive to forecast ANL_T and therefore generates higher prices for the top two hours of a day during periods with high loads and high levels of grid stress.

8 Summary of Recommendations

The MGCC Study Participants recommend that the Commission adopt the recommendations below, based on the analysis in this MGCC Study. It is also hoped that the parties to A.20-10-011, CEV rates, and A.19-11-019, its GRC Phase II will provide their support.

The MGCC Study Participants specifically recommend the CPUC adopt the following formula for setting the MGCC price in PG&E's DAHRTP rate:

Equation 6: Hourly MGCC Pricing Formula

$$\text{Hourly MGCC Price: PCAF-S}(ANL_T) = H / (1 + \exp(A - B^* ANL_T)) + E * \text{Flex Alert}$$

$$\text{PCAF-S}(ANL_T < L) = 0$$

ANL_T is normalized[60]

$$E = \$0.25$$

$$H = \$1.097$$

$$A = 18.78$$

$$B = 23.72$$

$$L = 27{,}713 \text{ MW}$$

The MGCC Study Participants anticipate 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 MGCC price of $90.35/kW-year, using the methods described in this report.[61] The value for E should only be updated if the CAISO updates the penalty price for ancillary services shortages.

Furthermore, the MGCC Study Participants recommend that the Commission and the Parties accept our finding that the inter-annual variability of generation rates resulting from the use of the recommended MGCC price will be reasonable and consistent with other capacity-related metrics, and the consequence that inter-annual variability of total bills is likely to be similar to that of the Original Applicable Tariff.

The MGCC Study Participants also suggest that as part of the final evaluation of the two DAHRTP programs, PG&E should re-convene the MGCC Study Working Group to re-evaluate the MGCC pricing formula. The Participants hope that both lessons learned from the application of the formula, and the potential availability of SERVM datasets that are better suited to this analysis, may also provide opportunities to improve the MGCC pricing formula.

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60 ANL_T is normalized using the formula: $(ANL_T – Min)/(Max – Min)$, where Min/Max are the minimum/maximum ANL_T values in the dataset.

61 The hourly price is determined using the variables H (maximum price contribution from the hourly "PCAF-S" function of ANL) and E (event-based adder), which are optimized to recover the total MGCC of $90.35/kw-year in an average year, and the variables A and B are determined using logistic regression using historical data, as explained in Section 3.

MGCC Study Participants recognize that the import limits used in the SERVM model reflect existing import RA contracts. It is likely that the CAISO market may import energy higher than RA contract levels, particularly when net loads in the rest of the WECC are not extremely high. Ideally a robust WECC model would reflect resource plans of all LSEs and simulate market frictions to replicate WECC wide operation. In the absence of a robust WECC wide model of non-CAISO entities' resource plans, MGCC Study Participants offer a recommendation to use historical import levels correlated with LSE NL from the balance of the WECC to inform modeled maximum imports.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

COMMUNITY CHOICE AGGREGATOR COLLABORATION

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COMMUNITY CHOICE AGGREGATOR COLLABORATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
COMMUNITY CHOICE AGGREGATOR COLLABORATION

A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) plan for collaboration with Community Choice Aggregators (CCA) in PG&E's service territory on various features of Demand Flexible (DF) rates and DF rate programs for implementation of full-scale Real Time Pricing (RTP) rates.[1] PG&E's goal is to be as transparent as possible about PG&E's RTP rates implementation, as well as providing a forum for CCA input into PG&E's RTP rate design and implementation plans.[2] The 12 CCAs in PG&E's service territory are projected to serve 53 percent of PG&E's service area load in 2026.[3] Thus, the potential for meaningful success through RTP-related load shift/load reduction/load growth in beneficial hours in Northern California absolutely depends on CCA customer participation in any RTP rates the California Public Utilities Commission (CPUC or Commission) might adopt for PG&E. Collaboration between PG&E and our CCAs on rate design, program design, and Load Management Standard (LMS)[4] compliance will be necessary—not only to realize the potential for RTP rates success but also to develop an

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1 In this testimony, PG&E refers to RTP rates adopted in its Expanded Pilots from Decision (D.) 24-01-032 as Hourly Flex Pricing (HFP) Pilots.

2 Assembly Bill 117 was passed in 2002 to establish Community Choice Aggregations, also known as Community Choice Energy, which offers an opportunity for communities to join together to offer Californians choice of their electric provider and the source of their electricity. In this chapter, DF rates refer to the hourly Day-Ahead RTP rates that have been deployed in PG&E's HFP Pilots and provide the basis for full-scale RTP rates contemplated in this filing.

3 California Energy Demand, 2024-2040, Forecast Files – LSE and BA Tables, Planning Forecast, Form 1.1.c. Electricity Deliveries to End Users by Agency (GWh), available at: <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0>, (accessed Oct. 14, 2025).

4 The California Energy Commission's (CEC) Load Management Standard required all large CCAs to submit compliance plans, available at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-lms-01> (accessed Oct. 19, 2025). Redwood Coast Authority and King City Community Power were not required to submit LMS compliance plans.

acquisition, support, dual participation, and Automation Service Provider engagement model that scales across PG&E's entire service territory.

B. Summary of Proposal

PG&E has been collaborating with the CCAs in regularly scheduled monthly meetings and weekly office hours on RTP rates since the August 2022 Decision approving Day-Ahead Hourly RTP.[5] In these meetings, PG&E reviews program goals and metrics, operational and systematic challenges, and lessons learned. Pilot evaluation data will be reviewed in these meetings as it becomes available. Currently 9 of the 12 CCAs in PG&E's service territory are also participating in PG&E's HFP Pilots ordered in D.24-01-032.[6] These regular meetings have provided an effective forum for PG&E to discuss and incorporate CCAs' feedback on program implementation and design decisions, and will continue to be the primary mechanism for collaboration between PG&E and the CCAs on RTP rates topics, as all parties are dependent on the learnings from the HFP Pilots to make informed decisions. PG&E plans to collaborate and seek feedback on three important topics in upcoming meetings with the CCAs:

1) RTP rate design, including generation, distribution, customer bill protection, subscription design, and transactive options.[7]
2) Facilitating understanding by the CCAs of PG&E's program design, including target segments and technologies, Marketing, Education and Outreach (ME&O) plans, the Automated Service Provider engagement model, compensation, technology incentives, and customer support.

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5 D.22-08-002 approved RTP Pilots for residential, commercial and industrial customers on the E-ELEC, B-6 and B-20 rates. Those pilots were ultimately replaced by the HFP Pilots in D.24-01-032. PG&E has an outstanding Petition for Modification to remove the requirements of D.22-08-002.

6 Current PG&E CCA participants include nine CCAs (out of PG&E's 12 total CCAs), namely: Central Cost Community Energy, Alameda County and the Valley Community Energy, Clean Power SF, Marin Clean Energy, Pioneer Community Energy, Peninsula Clean Energy, San Jose Clean Energy, Silicon Valley Clean Energy, and Valley Clean Energy. Sonoma Clean Power, Redwood Coast Energy Authority, and King City Community Power CCAs have not committed to participating.

7 PG&E's DF rate design proposal conforms with the CEC's LMS requirements as reflected in the CPUC's Guidance Decision in the DF Order Instituting Rulemaking (OIR) Track B (D.25-08-049), however it is at the discretion of each of the CCAs Boards whether to adopt the same rate design used for PG&E, and/or ensure that their own rate design conforms with their CEC-approved LMS plan.

3) Sharing lessons learned from the DF Pilots and ME&O efforts to foster customer understanding of both bundled and unbundled DF rate offerings.

PG&E will also use these bi-weekly working sessions to collaborate on systems and process design as required by the Enhanced Demand Response OIR (Rulemaking 25-09-004), and will also continue to collaborate with the CCAs while finalizing RTP rates proposals. As discussed in Chapter 4, PG&E is proposing a RTP Regulatory Roadmap to submit a Stop-Gap Interim RTP Pilot Proposal and Q4 2027 Updated Supplemental RTP Testimony that incorporates input from the CCAs.[8]

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[8] See Chapter 4.

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 4
REGULATORY ROADMAP FOR RTP IMPLEMENTATION AND COST-RECOVERY

A. Introduction and Summary of Proposals

This Chapter presents Pacific Gas & Electric's (PG&E) proposed Real Time Pricing (RTP) Regulatory Roadmap to ensure that the post-pilot RTP deployment plans ultimately adopted by the California Public Utilities Commission (CPUC or Commission) for PG&E are cost-informed and implemented in a targeted way to best support California's policy goals of decarbonization, affordability, and reliability. It was not possible for PG&E to develop and present its Operational Implementation, Measurement and Evaluation (M&E), and Marketing, Education and Outreach (ME&O) plans with associated cost estimates within the 60-day deadline Decision (D.)25-08-049 set for this Supplemental RTP Testimony.[1] In addition, on September 29, 2025, the CPUC issued a new Enhanced Demand Response Order Instituting Rulemaking (EDROIR) proceeding, which included addressing RTP systems and processes. Although the Investor-Owned Utilities (IOU) presented proposals for post-pilot RTP systems and processes in the Demand Flexibility Order Instituting Rulemaking (DFOIR) Track B Working Group Report,[2] after a long series of workshops obtaining input from many parties including intervenors and vendors, the Track B Decision did not provide any guidance but said post-pilot RTP

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1 See Section E for detailed definitions and discussion of the cost categories that need to be estimated for post-pilot RTP deployment and for extending the Hourly Flex Pricing (HFP) Pilots as discussed in Section D. For purposes of this testimony PG&E will refer to its ongoing Expanded RTP Pilots adopted in January 2024 as the HFP Pilots. PG&E's Phase II Vehicle to Grid Integration Pilots (Phase II VGI Pilots), which require RTP rates, are not considered to be part of the HFP Pilots. PG&E's Expanded RTP Pilots were adopted in D.24-01-032 and include residential, small and medium business, large commercial and industrial and agricultural customers. The Phase II VGI Pilots were adopted in RES E-5192, issued May 6, 2022. Rate design for the Phase II VGI Pilots were adopted in RES E-5326, issued July 17, 2024. The budget for implementation of the Phase II of VGI Pilots was approved in RES E-5358 on December 19, 2024. The Phase II VGI Pilots include commercial electric vehicle charging customers on hourly day ahead RTP rates with the same design as the RTP rates in the HFP Pilots per AL 7234-E-A.

2 R.22-07-005, CPUC, DFOIR, Track B Working Group Report (Oct.11, 2023).

systems and processes would be addressed in another forthcoming proceeding.[3] PG&E expects that the EDROIR will define the scope of some specific post-pilot RTP systems and processes, leveraging the already-existing DFOIR Track B Working Group 2 efforts, which PG&E hopes will be clarified in an EDROIR pre-hearing conference, expected in late December 2025, as well as the EDROIR scoping memo that would follow. However, an EDROIR proposed decision is not expected until Q3 2026, which means a final decision could be issued as late as November 2026. At a minimum, whatever additional guidance the EDROIR will provide on the IOUs' systems and processes for post-pilot RTP deployment are needed to develop PG&E-specific cost estimates.[4]

Finally, PG&E's HFP Pilots continue to provide real-world data and learnings that are relevant to post-pilot RTP deployment planning, both related to RTP rate design as well as Operational Implementation and ME&O strategy. The HFP Pilots' midterm M&E results, including critical data on customer adoption and load impact (load shift/load reduction/load growth in beneficial hours), are expected in August 2026.

Given that guidance from the EDROIR proceeding and data from HFP Pilots' midterm M&E results are not expected until later in 2026, PG&E's RTP Regulatory Roadmap, detailed in Section F, proposes that PG&E submit an update to this Supplemental RTP Testimony in Q3 2027 (Q3 2027 Updated Supplemental RTP Testimony). This submission in Q3 2027 would contain a full post-pilot RTP deployment proposal with a final rate design as well as Operational Implementation, M&E and ME&O plans, cost estimates and a cost-recovery proposal. This proposal will incorporate any guidance from the EDROIR Decision expected in late 2026 and the HFP Pilots' midterm M&E results expected in August of 2026. See Section D.2 for more details on

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[3] R.25-09-004, Order Instituting Rulemaking to Enhance Demand Response in California (issued Sept. 29, 2025), p. 8. "In Decision 25-08-049, the Commission noted that issues relating to systems and processes to enable access to dynamic rates to implement Load Management Standards will be addressed in one or more new rulemakings. This rulemaking will address the implementation of dynamic rates by developing the appropriate systems and processes but will not address the rate design aspects of the dynamic rates being used by these systems and processes."

[4] See Table 4-1 for a list of systems and process cost categories for which PG&E will need to develop cost estimates for post-pilot RTP deployment.

PG&E's proposed Q3 2027 Updated Supplemental RTP Testimony for post-pilot RTP deployment.

PG&E also proposes an earlier, January 2026 submission of testimony setting forth a Stop-Gap Interim RTP Pilot proposal to extend PG&E's HFP Pilots until PG&E is able to program post-pilot RTP rates into our modernized billing system. PG&E currently expects to complete its Billing Modernization Initiative (BMI) by the end of 2029. If this completion date is achieved, RTP rates could be built in the modernized billing system in 2030 and potentially become available to our customers in 2031. PG&E will provide an update on the timing for implementing post-pilot RTP rates into PG&E's modernized billing system in our proposed Q3 2027 Updated Supplemental RTP Testimony.[5] Only with a Stop-Gap Interim RTP Pilot (HFP Pilots extension) can PG&E ensure that customers will have uninterrupted access to an opt-in RTP rate beyond the currently adopted conclusion of the HFP Pilots on December 31, 2027.[6] See Section D.1 for more details on PG&E's proposed January Stop-Gap Interim RTP Pilot Proposal, and Section C.3 for further discussion of the billing implementation constraints due to PG&E's BMI.

Figure 4-1 illustrates PG&E's proposed RTP Regulatory Roadmap needed to get to post-pilot RTP deployment, highlighting our two proposed additional submissions, as well as when CPUC decisions are needed in order to meet deployment targets.[7] Chronologically, PG&E first needs a CPUC decision, by November 19, 2026, approving our January 2026 Stop-Gap Interim RTP Pilot Proposal. This first PG&E Stop-Gap Interim RTP Pilot Proposal decision would

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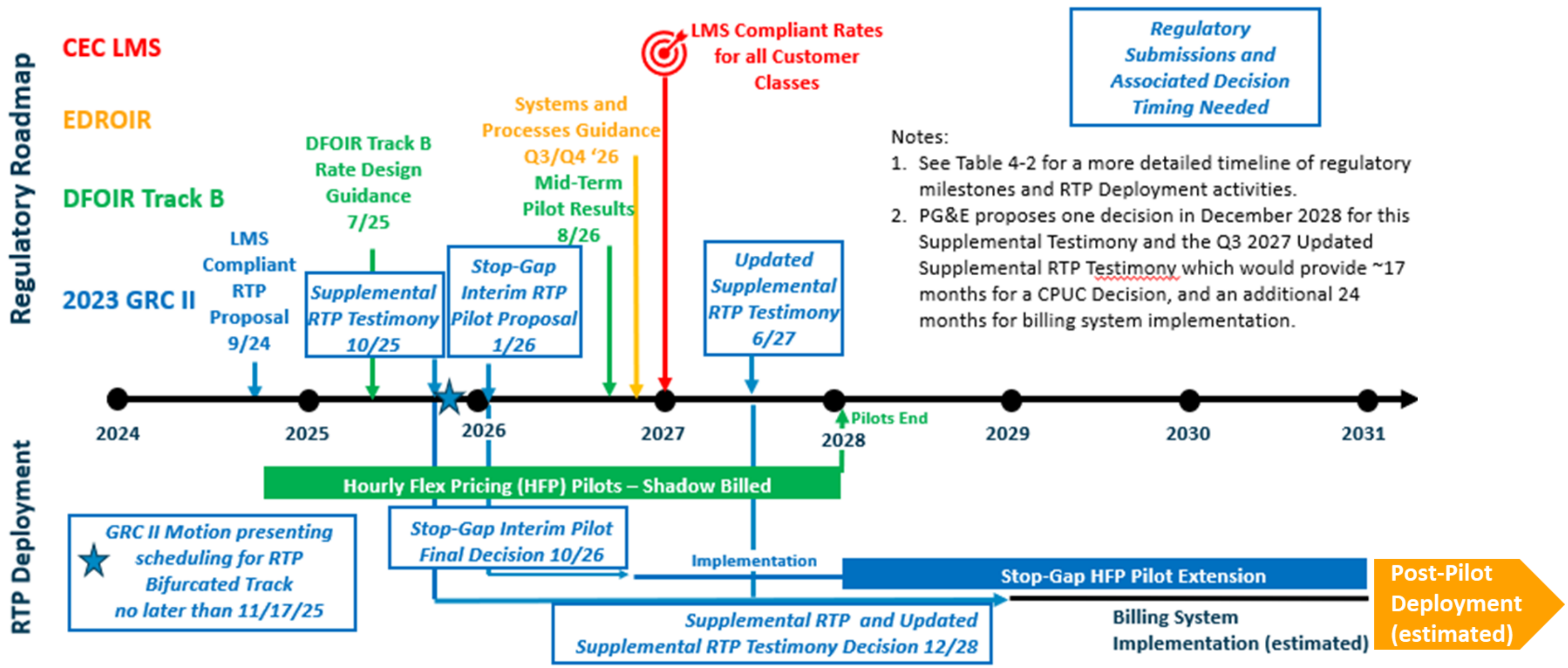
5 PG&E's Billing Modernization Initiative is being litigated in A.24-10-014 with a Decision expected Q2 2026.

6 20 CCR, § 1623(d)(2) requires a CPUC-adopted RTP rate to be available for all customers starting January 1, 2027. However, 20 CCR, § 1621(g) also provides that the type of RTP rates the CEC's LMS policies envision will not become effective until the CPUC has conducted ratesetting proceedings, since only the CPUC has the jurisdiction to set rates for the IOUs.

7 The schedule for these two proposed additional submissions will be included in the Motion presenting scheduling proposals for the bifurcated track for Dynamic Rate Options due no later than November 17, 2025. Administrative Law Judge's Ruling Modifying Schedule and Setting a New Track for Dynamic Rate Options (Oct. 9, 2025) (ALJ Atamturk Ruling) p. 4, Ordering Paragraph (OP) 3). Note that this testimony was finalized before the required Motion's proposed scheduling options had been completed.

ensure there is enough time to implement the Stop-Gap decision by the ongoing PG&E HFP Pilots' current expiration date of December 31, 2027. A second, later CPUC Decision, on PG&E's post-pilot RTP deployment, is requested for December 29, 2028, addressing both this Supplemental RTP Testimony as well as PG&E's Q3 2027 Updated Supplemental RTP Testimony with process and system costs, M&E and ME&O plans and costs, as well as RTP rate design improvements. The proposed post-pilot RTP decision schedule would provide ~17 months for a CPUC Decision after the Q3 2027 Update, and an additional 24 months for post-pilot RTP deployment that will involve enhancements to current systems, processes, and program offerings. As explained above, this proposed RTP Regulatory Roadmap would also ensure RTP rates are available to all of PG&E's customer classes until post-pilot RTP rates can be billed in PG&E's modernized billing system. If the CPUC does not approve the January 2026 Stop-Gap Interim Pilot Proposal or the Q3 2027 Updated Supplemental RTP Testimony elements of our RTP Regulatory Roadmap, PG&E requests that the CPUC issue an interim decision: 1) authorizing PG&E to file a Tier II advice letter to continue the HFP pilots after December 31, 2027, until the BMI is completed and RTP rates are built in the billing system, and 2) establishing the schedule and / or proceeding for further testimony on post-pilot RTP rates and related processes and system costs.

FIGURE 4-1
PG&E'S RTP REGULATORY ROADMAP AND RTP DEPLOYMENT ACTIVITIES



B. Organization of the Rest of This Chapter and Witness Responsibilities

This Chapter also includes the following additional sections:

Section C – Post-Pilot RTP Deployment Must Be Informed by Upcoming Information, discusses three important critical path elements that shaped the timing in our proposed RTP Regulatory Roadmap:

1. Any guidance on systems and processes and associated costs for post-pilot RTP deployment from the EDROIR is assumed would be provided as late as November 2026.
2. HFP Pilots' midterm M&E results are needed and are expected to be available in August 2026.
3. PG&E's BMI constraints mean programming post-pilot RTP rates is not possible until in or after 2030.

Section D – Getting to Post-Pilot RTP Deployment - Submissions Needed, provides additional detail on the two new proposed submissions described above that are needed in the Bifurcated RTP Track of this proceeding, a Stop-Gap Interim RTP Pilot Proposal in January 2026, and Updated Supplemental RTP Testimony in Q3 2027.

Section E – Cost Estimate Categories, identifies the cost categories that need to be estimated for extending the HFP Pilots and for post-pilot RTP deployment.

Section F – PG&E's Proposed RTP Regulatory Roadmap, details the specific regulatory submissions, RTP deployment activities and associated timelines needed to present PG&E's proposals for extending PG&E's HFP Pilots and for post-pilot RTP deployment after the conclusion of the HFP Pilots.[8]

Section G – Conclusion, summarizes PG&E's Exhibit 5, Chapter 4 testimony.

The witness responsibilities for this chapter are as follows:

- Emily Bartman – All sections of this chapter except for Section C.2.b.
- Jamie Chesler – Section C.2.b.

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[8] PG&E's Business Electric Vehicle (BEV) RTP rates are currently being tested in the Phase II VGI Pilots. The Phase II VGI Pilots, which started in October 2024, are authorized to continue until funding is depleted (Resolution E-5358, issued Dec. 26, 2024, approved the budget for Phase II VGI Pilots). PG&E expects to include the BEV RTP customers in the Stop-Gap Interim RTP Pilot Proposal to extend the HFP Pilots in our proposed January 2026 submission.

C. Post-Pilot RTP Deployment Must be Informed by Upcoming Information

This section discusses three important critical path elements that shaped the timing in our proposed RTP Regulatory Roadmap: 1) Any guidance on systems and processes and associated costs for post-pilot RTP deployment from the EDROIR Decision is assumed would be provided no later than November 2026, 2) HFP Pilots' midterm M&E results are needed and are expected to be available in August 2026, and 3) PG&E's Billing Modernization Initiative (BMI) constraints mean programming new post-pilot RTP rates in the billing system will not be possible until in or after 2030.

1. Any Guidance on Systems and Processes and Associated Costs for Post-Pilot RTP Deployment from the EDROIR Decision is Assumed Would Be Provided No Later than November 2026

As described in Chapter 1, D.25-08-049 moved the scoping issues from the DFOIR Track B regarding the systems and processes for the implementation of LMS-compliant RTP rates to the EDROIR proceeding.[9] Opening Comments in the new EDROIR proceeding are due November 13, 2025. A Proposed Decision in the EDROIR is currently targeted to be issued as early as Q3 2026, which suggests that a final CPUC EDROIR Decision could likely be issued as late as November 2026.

2. HFP Pilots' Midterm M&E Results are Needed and Are Expected to Be Available in August 2026

As described in Chapter 1, PG&E is conducting ongoing HFP Pilots and Phase II VGI Pilots as approved by the CPUC. HFP Pilots' midterm M&E results are expected in August 2026. These results are critical to the

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[9] In D.25-08-049, adopted on August 28, 2025, the CPUC did not address timing for provision of cost estimates for LMS-compliant rates. Instead, it indicated that the CPUC planned to address costs in another forthcoming proceeding. However, D.25-08-049 directed the IOUs to provide Supplemental RTP Testimony 60 days after the Decision (on October 29, 2025) that addresses all of the requirements set in the Decision. Since PG&E already provided its LMS-compliant RTP rate proposal in A.24-09-014, D.25-08-049 directed PG&E to provide Supplemental RTP Testimony on LMS-compliant RTP rate design in that proceeding. Then, on September 8, 2025, the CPUC issued the EDROIR (R.25-08-004) that includes in scope the systems and processes needed for post-pilot RTP deployment that will ultimately be adopted in the bifurcated RTP track of A.24-09-014.

development of the post-pilot RTP rate design and ME&O plans and cost estimates.

a. HFP Pilots' Midterm M&E Results Could Necessitate Updates to the Post-Pilot RTP Rate Design

HFP Pilots' midterm M&E results expected in August 2026 will provide insights on: (1) customer load response to price (load elasticity) by customer sector, end use, and technology adoption (e.g., storage, electric vehicles, etc.); (2) net benefits of that load response (considering electric system value and revenue recovery); (3) how the load response is affected by rate design (e.g., subscriptions, other elements of the pilot rate design); and (4) the impact of price risks on customer retention.

Continued iteration of RTP rate design is likely to be needed. For example, PG&E has already identified the need to change elements of our HFP Pilots rate design. Two specific examples follow: (1) It has become clear that the initial subscription component of the HFP rate needs refinement to improve customer understanding, such as by removing the after-the-fact scaling of the subscription quantity and using actual demand values in each month, and (2) Distribution pricing, which so far has been done at a circuit-cluster level, needs more investigation to determine what level of topographical aggregation provides a meaningful price signal that accurately reflects the grid conditions experienced by each individual customer. Pilot learnings are a critical input to continued iteration of RTP rate design to ensure that Californians' actual response to the HFP pilots' rates is considered (both for willingness to opt-in as well as ability to achieve the desired load shifts) through iterative analysis to arrive at the most optimal rate design for post-pilot RTP deployment proposals.[10]

Therefore, additional learnings from the HFP and VGI Pilots may warrant changes to the RTP rate design proposed in Chapter 2.

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10 See Chapter 2, Section H.9.

Specifically, Chapter 2 discusses the following rate design items that may need revisions as PG&E learns from the HFP Pilots:[11]

- Refinements to Marginal Energy Cost line losses
- Alternative distribution rate designs that incorporate actual capacity constraints
- Long-term solutions for changing circuit configurations
- Alternative distribution aggregations
- Improvements to non-marginal cost rate design
- Improvements to subscription design
- Potential for double payment.

PG&E recognizes that certain other utilities have some experience with deploying RTP rates, the learnings from which PG&E can continue to leverage to help inform our next step proposals for RTP. However, PG&E has concluded that it is also necessary to incorporate learnings from the PG&E's CPUC-authorized HFP Pilots (launched in November 2024), as well as from the Phase II VGI Pilots (launched in October 2024), before PG&E can propose the best approach to post-pilot RTP deployment. Below are several reasons PG&E finds it critically important to incorporate learnings from the Pilots being run in our service area:

- The LMS-driven rate structure that D.25-08-049's[12] guidance calls for PG&E and other California IOUs to propose is complex, particularly as it seeks to expose participating customers not only to variable generation prices, but also to dynamic locational *distribution* prices (and dynamic *transmission* prices). Additionally, the DFOIR Track B Decision's guidance seeks distribution pricing that is disaggregated according to

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11 See Chapter 2, Section O.2.

12 On September 29, 2025, SDG&E filed an Application for Rehearing of D.25-08-049 (AFR) on the grounds that it is based on an insufficient record and insufficient procedural process and fails to take into consideration any costs associated with the prescribed rate design. On October 14, 2025, PG&E filed a response supporting the AFR's position that D.25-08-049 lacks necessary cost effectiveness evidence and findings to support its direction to the IOUs for RTP rates. The Small Business Utility Advocates (SBUA), and the Center for Accessible Technology (CforAT) also each filed responses supporting SDG&E's request for rehearing.

distribution grid topography.[13] As is clear from the learnings thus far from the various RTP pilots (described in Chapters 1 and 2), including a disaggregated distribution price signal complicates the customer experience with pricing, as well as the associated load response incentives. It is critical that PG&E and stakeholders establish the best path forward on the desired disaggregated distribution rate element prior to proposing the most effective rate design for post-pilot RTP deployment for PG&E;

- Other power providers have experienced significant challenges with exposing certain types of customers, particularly residential customers, to RTP rates during periods of unusually high prices.[14] PG&E is still evaluating the best approaches to managing risk for participating customers, while still appropriately incenting load response and ensuring appropriate revenue recovery to avoid unfair cost shifts among customers;
- PG&E's electricity consumers have particular dynamic pricing needs due to California-specific factors, discussed below, relating to climate, technology adoption, other complex rates structures (such as Net Energy Metering (NEM) and the successor Net Billing Tariff (NBT)), as well as California's unbundled vs. bundled retail service structure, which involves Community Choice Aggregators (CCA) and Direct Access providers. For example:
  - *Climate:* Agricultural customers in California have highly variable water pumping needs that are particular to California's

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[13] California Code of Regulations (CCR) Title 20, Div. 2, Ch. 4, Art. 5, § 1623(a)(1), subject to CPUC and Federal Energy Regulatory Commission approval.

[14] See for example: 1) The impact of Winter Storm Uri on real time prices in Texas in February 2021 (Bohra, N, Griddy Customers Moved to Other Electricity Providers After ERCOT Boots it From Texas Market (Feb. 26, 2021), available at: <https://www.texastribune.org/2021/02/26/griddy-texas-ercot-electricity-costs/> (accessed October 3, 2025)); and 2) In Denmark where RTP is more widely adopted, the Danish government bailed out customers affected by price spikes caused by the Russian invasion of Ukraine (Reuters, Denmark to Offer Energy Price Support Despite Central Bank Warning (Sept. 23, 2022), available at: <https://www.reuters.com/markets/europe/denmark-soften-impact-high-energy-prices-2022-09-23/> (accessed Oct. 3, 2025)).

mediterranean climate which experiences drought conditions as well as long periods with no precipitation..

- *Technology Adoption and Complex Rate Structures:* California has some of our country's highest adoption rates of customer solar and storage. NEM and NBT may present particular challenges for incenting load response from residential solar customers if RTP's rate design reduces their solar export compensation.
- *Retail Service Structure:* PG&E has twelve CCAs operating in our service area who serve a large portion of customers and load in our service territory. Specifically, because CCAs provide generation services for approximately half of the load in PG&E's service area,[15] it is critical to establish an RTP rate structure and related systems and processes at reasonable costs that can encourage CCA collaboration with our post-pilot RTP deployment. PG&E's approach to collaborating with CCAs is further discussed in Chapter 3 of this Testimony.

b. HFP Pilots' Midterm M&E Results Will Guide Post-Pilot RTP Deployment ME&O Plans and Cost Estimates

A comprehensive understanding of the final RTP rate structure, priority customer segments, rollout timelines, and enrollment targets, is essential to developing post-pilot RTP deployment ME&O plans and cost estimates. PG&E's ME&O strategy will be tailored to support enrollment objectives by focusing on customer segments that currently use or are interested in technologies enabled by Automation Service Providers (ASP). These efforts aim to help customers optimize their performance under RTP rates. However, given that key pilot insights are still pending and the final RTP rate design will continue to evolve as described above in Section C.2.a, it is premature to develop and finalize

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15 California Energy Demand, 2024-2040, Forecast Files – LSE and BA Tables, Planning Forecast, Form 1.1.c. Electricity Deliveries to End Users by Agency (GWh), available at: <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0.> (accessed Oct 14, 2025). For 2026, the forecasted percent of PG&E's load served by CCAs is 53 percent.

an ME&O plan or estimate the funding required for post-pilot RTP deployment.

PG&E anticipates that learnings from our HFP pilots will yield data-driven insights to refine ME&O strategies. These insights will enable PG&E to scale RTP offerings across its customer base and include consideration of ASP acquisition and automation capabilities given what we learn. The HFP Pilots' Midterm M&E results are expected to shed light on customer engagement with RTP signals, responsiveness to price forecasts, and behavioral shifts such as load shift / load reduction / load growth in beneficial hours. These findings will inform adjustments to customer outreach strategies to foster sustained participation. Additionally, pilot data will provide customer segment-specific performance metrics, allowing PG&E to assess participation rates and identify customer groups most receptive to RTP.

3. PG&E's Billing Modernization Initiative Constraints Mean Programming Post-Pilot RTP Rates is Not Possible Until In or After 2030

As described in PG&E's Opening Testimony, PG&E is currently undertaking a multi-year BMI, which began in 2020 and is expected to be completed in Q4 of 2029.[16] PG&E must modernize its outdated billing systems to continue to deliver reliable customer service, including continuing to provide billing services to customers. This BMI will also allow more efficient implementation of future structural changes to the new billing system, including new rates and rate programs and modifications to existing rates and rate transitions.

There are limits to PG&E's ability to implement the large number of already adopted projects in PG&E's Rates Implementation Pipeline and any additional new rate proposals adopted in this proceeding would require changes to the billing system after the completion of the BMI. Additionally, PG&E has a significant backlog of rate projects that have already been adopted by the CPUC but are not yet able to be programmed into PG&E's billing system. As explained in Opening Testimony, if the CPUC were to

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[16] Exhibit (PG&E-3), Errata to April 18, 2025 Prepared Testimony (July 18, 2025), p. 11-1, line 26 to p. 11-7, line 7.

adopt any new rate proposals that require modifications to PG&E's billing systems, programming may need to be delayed until after the BMI has been finalized in Q4 2029 or later and then prioritized among the previously adopted rate projects already in PG&E's rates implementation pipeline. PG&E estimates that post-pilot RTP rates could be built in the billing system no earlier than 2030 and then launched in the modernized billing system in 2031 or later.

D. Getting to Post-Pilot RTP Deployment – Submissions Needed

PG&E proposes two additional submissions in this proceeding: (1) a Stop-Gap Interim RTP Pilot Proposal is needed to ensure uninterrupted customer access to an RTP rate, and (2) an update to this Supplemental RTP Testimony is needed in Q3 2027 to provide post-pilot RTP deployment plans and cost estimates.[17]

1. A Stop-Gap Interim RTP Pilot Solution is Needed to Ensure Uninterrupted Customer Access to an RTP Rate

This section describes the Stop-Gap Interim RTP Pilot Proposal to be submitted January 30, 2026, to extend the currently adopted end-date for PG&E's HFP Pilots. This Stop-Gap Interim RTP Pilot Proposal is necessary to ensure there is no interruption in PG&E's provision of RTP rates to our customers. PG&E's HFP Pilots are currently scheduled to conclude at the end of 2027, but post-pilot RTP rates cannot be built in PG&E's modernized billing system earlier than 2030, as described in Section C.3 above. Without a CPUC-adopted plan to extend PG&E's HFP Pilots through 2028, 2029 and 2030, customers participating in the HFP Pilots as of December 31, 2027 would have to be unenrolled from the HFP Pilots rates and would need to be re-recruited once the new post-pilot RTP rates are programmed in PG&E's

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[17] These two proposed additional submissions and their timing will be presented in the Motion presenting scheduling proposals for the bifurcated track for Dynamic Rates due no later than November 17, 2025. ALJ Atamturk Ruling, p. 4, OP 3. Note that this testimony was finalized before the required Motion's proposed scheduling options had been completed.

Billing System in or after 2030, and launched in or after 2031.[18] In the January 2026 Stop-Gap Interim RTP Pilot Proposal, PG&E will request that the CPUC issue an expedited Decision extending our ongoing HFP Pilots until at least December 31, 2030, or whenever thereafter the post-pilot RTP rates have been programmed and can instead be billed through our modernized billing system.

PG&E is currently developing alternatives to expanding the HFP Pilots and may present different options in the January proposal. Although PG&E is still defining the specific options to be evaluated, one option may be the minimum required effort, continuing with the current rate design and requesting additional funding only for ongoing program management and vendor technology costs and possibly extending Community CCA and ASP incentives. Another option might be to include substantial changes to rate design that would require substantive enhancements to billing systems and processes, such as, but not limited to, changing subscription approach, changing dynamic distribution rate structure, adding a dynamic transmission rate component, and / or adding RTP charges in addition to credits to the shadow billed annual true-up. PG&E will also request that a Decision be issued by November 19, 2026. This timing for a decision ten months after the submission of the January 2026 Stop-Gap Interim RTP Pilot Proposal would allow the amount of time necessary if PG&E will be making substantial changes to the HFP RTP rate design. If the CPUC decides to adopt an option that merely extends the current HFP Pilots rate design, less time will be needed between the Decision and January 1, 2028 (i.e., January 1, 2028 being the start of the HFP Pilots extension).

2. An Update to This Supplemental RTP Testimony is Needed in Q3 2027 to Provide Post-Pilot RTP Deployment Plans and Cost Estimates

PG&E proposes that its post-pilot RTP deployment plans, associated cost estimates and cost recovery method be presented, vetted and adopted in an update to this Supplemental RTP Testimony in Q3 2027. See Section

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[18] As of October 15, 2025, PG&E’s HFP and Phase II VGI Pilots had a total of 2,077 enrolled service agreements representing 315 MW of load. Enrollment targets for the HFP Pilots have been exceeded. The Phase II VGI Pilots do not have enrollment targets.

E for more information about the specific cost categories for which PG&E proposes to provide cost estimates in our Q3 2027 Updated Supplemental RTP Testimony for post-pilot RTP deployment.

The Q3 2027 Updated Supplemental RTP Testimony is needed in order to incorporate any guidance provided by the EDROIR Decision on systems and process costs, as described in C.1 above and to incorporate HFP Pilots' midterm M&E results as described in C.2 above. The EDROIR Proposed Decision is not expected until Q3 2026, which could be as late as September 2026, with a Final Decision as late as November 2026. Our requested Q3 2027 Updated Supplemental RTP Testimony would provide about seven months to incorporate any guidelines and directives from an EDROIR final decision in November 2026. At least seven months is warranted after the EDROIR Decision is issued, to interpret the guidance which may have complex requirements such as Statewide systems and processes and also to perform the required collaboration with CCAs. Also, a decision later than November 2026 and/or any requirements for coordination across CCAs and / or other IOUs could ultimately take longer than seven months and timelines would need to be adjusted.

Because the HFP Pilots would be extended at least through 2030, if PG&E's January 2026 Stop-Gap Interim RTP Pilot Proposal is approved, a Q3 2027 submittal for the Updated Supplemental RTP testimony, with full post-pilot RTP deployment plans, would provide a long runway (~30 months) for procedural steps required for intervenor vetting and input, a Decision (December 29, 2028), and the implementation work needed to bill the post-pilot RTP rates in PG&E's billing system in 2031 or later (assuming BMI is completed by Q4 2029), and execute PG&E's Operational Implementation, M&E and ME&O plans.

E. Cost Estimate Categories

PG&E is not providing cost estimates in this Supplemental RTP Testimony but proposes to provide cost estimates for each of the relevant cost categories detailed in Table 4-1 in our January 2026 Stop-Gap Interim RTP Pilot Proposal (for extending the HFP Pilots) and Q3 2027 Updated Supplemental RTP Testimony (for post-pilot RTP deployment). If the CPUC does not approve the January 2026 Stop-Gap Interim Pilot Proposal or the Q3 2027 Updated

Supplemental RTP Testimony elements of our RTP Regulatory Roadmap, PG&E requests that the CPUC issue an interim decision: 1) authorizing PG&E to file a Tier II advice letter to continue the HFP pilots after December 31, 2027, until the BMI is completed and RTP rates are built in the billing system, and 2) establishing the schedule and / or proceeding for further testimony on post-pilot RTP rates and related processes and system costs.

TABLE 4-1
COST CATEGORIES RELATED TO HFP PILOTS EXTENSION AND POST-PILOT RTP DEPLOYMENT

Line No.	Type	Cost Category	Description	Cost Estimate Dependencies
1	Operational Implementation – Systems and Processes	PG&E Billing System Modifications	Programming post-pilot RTP rates into PG&E’s internal billing system to issue customer bills.	Conclusion of BMI expected by Q4 2029 when programming post-pilot RTP rates could begin (at the earliest) and issuance of EDROIR guidelines on Systems and Processes in Q3/Q4 2026
2		Interim RTP Billing (currently GridX)	Interim billing system currently providing shadow billing for HFP Pilots with an external vendor. Could potentially be moved in-house.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
3		Pricing Platform (currently GridX)	System to calculate and disseminate hourly generation and distribution prices for HFP Pilots. Could potentially be moved in-house.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
4		Transactive Platform (currently Polaris)	System to enable Agricultural customers to execute forward purchases of energy up to 7 days in advance. Could potentially be moved in-house.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
5		Subscription Manager (currently GridX)	System to calculate and disseminate pre- and post-subscription quantity by HFP Pilot-enrolled Service Agreement. Could potentially be moved in-house.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
6		Rate Plan Comparison and Bill Estimation Tools / Systems	System to enable user to analyze customers’ bill impact based on historical energy usage patterns and prices as well as a future “what-if” analysis assuming changes to energy usage, adoption of technologies and / or forecasts of future prices.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
7		Call Center and Customer Service Representative Support Applications	Systems and tools necessary to enable customer support staff to educate, enroll and support customers on dynamic rates. Will require visibility into Distributed Energy Resource (DER) performance.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026

TABLE 4-1
COST CATEGORIES RELATED TO HFP PILOTS EXTENSION AND POST-PILOT RTP DEPLOYMENT
(CONTINUED)

Line No.	Type	Cost Category	Description	Cost Estimate Dependencies
8		Rate Change Portals	System to enable customers and ASPs to modify a customer's rate schedule and elect for any optional components (e.g., subscription percentage).	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
9		ASP Data Access and Sharing	System to enable two-way data sharing with ASPs for information such as customer billing, interval data, rate / Rate Identification Number (RIN), enrollment, prices, transactions, and DER. performance / control signals (i.e., how DERs are performing against prices).	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
10		Non-NEM Export Enrollment Application Process	Through PG&E's Electric Grid Interconnection (EGI) department.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
11		Share My Data (SMD) Platform	System to enable two-way data sharing with 3rd parties for information such as customer billing, interval, and rate / RIN.	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
12		Single Statewide Tool	LMS-required Single Statewide Tool (scoping still in process, but LMS requires a Single Statewide tool that facilitates rate comparisons, rate changes and mapping of customer to RINs in the CEC Market Informed Demand Automation Server (MIDAS) platform).	EDROIR guidelines on Systems and Processes in Q3/Q4 2026
13	Operational Implementation – Program Management	Program Management	Program / product management teams to implement, operate and manage the program lifecycle cross-functionally.	HFP Pilots' midterm M&E results expected in August 2026
15		Vendor Management	Project Management of vendors providing billing, subscription and transactive services for PG&E. Current vendors are GridX and Polaris.	HFP Pilots' midterm M&E results expected in August 2026

TABLE 4-1
COST CATEGORIES RELATED TO HFP PILOTS EXTENSION AND POST-PILOT RTP DEPLOYMENT
(CONTINUED)

Line No.	Type	Cost Category	Description	Cost Estimate Dependencies
16		ASP Engagement	Enable proactive ownership by ASPs of their role in and impact on dynamic rates' success. Implement collaborative processes to monitor effectiveness and build confident data-backed understanding of specific customer segment adoption, affinity, and performance.	HFP Pilots' midterm M&E results expected in August 2026
17		CCA Collaboration	Collaboration with CCAs in PG&E's service territory on features of post-pilot RTP deployment. See Chapter 3 for more details.	None
18		MIDAS / RIN Regular Updates	CEC LMS-required daily uploads of day-ahead hourly prices to the CEC's MIDAS system with a unique RIN code for customer-specific rate combination that includes an RTP rate, including PG&E's cost of developing and maintaining and uploading RINs on a daily basis.	None
19		Customer Support	Customer Service Representative teams to provide customer education, enrollment and support services, including Account Representatives of large customers.	Program goals and number of enrollments
20		Billing Processes	Internal Billing Operations teams to address and remediate billing exceptions.	Program goals and number of enrollments
21		Incentives	Incentives for CCA enrollments, ASP enrollments / technologies and customer technologies.	Program goals and number of enrollments and HFP Pilots' midterm M&E results expected in August 2026
22	Measurement & Evaluation (M&E)	Vendor Contracts	Post-pilot RTP deployment data gathering and analysis to gain insights to continue to improve RTP effectiveness.	None
23	ME&O	Marketing, Education, and Outreach	Informational and recruitment material developed for physical and digital channels to educate and acquire customers onto dynamic rates.	HFP Pilots' midterm M&E results expected in August 2026

F. PG&E's Proposed RTP Regulatory Roadmap

Because of the timing constraints discussed above, at this time PG&E is proposing a RTP Regulatory Roadmap that encompasses both the nearer-term need for approval of a stop-gap solution that extends our ongoing HFP Pilots beyond their current December 31, 2027 end date, as well as provides for post-pilot RTP deployment. A more detailed schedule with specific requested dates is presented in Table 4-2 below. These two proposed additional submissions and their timing will be presented in PG&E's Motion for Approval of Schedule in the bifurcated GRCII track for Dynamic Rates, due no later than November 17, 2025.[19]

PG&E's proposed RTP Regulatory Roadmap will allow our customers to have continued access to RTP rates, without interruption, by extending our HFP Pilots beyond 2027 until the post-pilot RTP rates, to be adopted later in this proceeding, can be programmed into our modernized billing system. This RTP Regulatory Roadmap also ensures the CPUC will be able to review all associated Operational Implementation, M&E and ME&O activities and costs, so that the new RTP rate design and associated programs are as cost-informed as possible. It will incorporate learnings from California customers on the RTP pilots, through at least HFP Pilots' midterm M&E results expected in August 2026, as well as incorporate guidance from the EDROIR Proposed Decision expected by late September, with a Final Decision as late as November 2026.

As described in Chapter 2 and Section C.2, the updated RTP rate proposal needs to be informed by actual HFP Pilots experience and midterm M&E results. Not only do real world results inform the design of the rate, but cost estimates for rolling it out also need to be informed by learnings from the HFP Pilots' midterm M&E results as well as by the outcome of the EDROIR proceeding which will be addressing systems and processes needed for post-pilot RTP deployment.

Therefore, PG&E requests, as part of this RTP Regulatory Roadmap, that it be allowed to serve Updated Supplemental RTP Testimony on the RTP rate design and post-pilot RTP deployment plans in Q3 2027 to allow for the necessary iterative analysis of the most relevant California-based RTP performance as well as meaningful cost estimates informed by the EDROIR.

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[19] ALJ Atamturk Ruling, p. 4, OP 3. Note that this testimony was finalized before the required Motion's proposed scheduling options had been completed.

An added advantage for PG&E to present finalized RTP proposals in the Q3 2027 Updated Supplemental RTP Testimony is that a Decision on the PG&E billing system modernization initiative (BMI) application will have been issued (expected in Q2 2026). That Decision should confirm PG&E's current estimated timing for completion of the BMI and the ability to program post-pilot RTP rates in the new billing system, currently estimated in 2030 or later, for a 2031 or later launch. Meanwhile, PG&E plans to propose the interim billing approach in the Stop-Gap Interim RTP Pilot Proposal in January 2026.

Table 4-2, below, provides a detailed timeline for regulatory activities needed to extend PG&E's HFP Pilots and for post-pilot RTP deployment after PG&E's BMI is completed in Q4 2029 or later. It also includes other critical path activities such as EDROIR milestones and the HFP Pilots' midterm M&E results.

TABLE 4-2
PG&E' RTP REGULATORY ROADMAP FOR POST-PILOT RTP DEPLOYMENT AFTER PG&E'S BILLING MODERNIZATION IS COMPLETED

Line No.	Date	Activity	Proceeding	Description/Purpose/Relevance	Decision/Approval Needed
1	9/30/24	Opening Testimony	A.24-09-014 2023 GRC Phase II (2023 GRC II)	Met LMS requirement for RTP proposals for all customers with three components (generation, distribution and transmission) by January 2027. Outlined the plan for obtaining Federal Energy Regulatory Commission (FERC) approval of the transmission component.	N/A
2	10/29/25	Supplemental RTP Testimony	A.24-09-014 2023 GRC II	Presents Supplemental RTP Testimony revising PG&E's 9/30/24 RTP proposal in A.24-09-014, to address D.25-08-049's (DFOIR Track B Decision) guidance for including expanded discussions on rate design elements, customer protection approaches, and plans for CCA coordination.	CPUC Decision needed by 12/29/28 to ensure enough time to begin programming in 2030 at the earliest when Billing Modernization is complete in Q4 2029 or later. Time is needed before programming starts to develop business requirements for all impacted systems and collaborate with CCAs.
3	11/13/25	Opening Comments	R. 25-09-004 EDROIR	PG&E's EDROIR Opening Comments will focus on: 1. Confirming the systems and processes that are in scope. 2. Confirming that specific costs will be addressed in the EDROIR and the specific cost categories.[a] 3. Confirming that cost estimates and cost recovery will be addressed in IOU-specific proceedings (2023 GRC II for PG&E) and not the EDROIR proceeding. 4. Confirming that cost estimates will need to be informed by the Decision guidance in R.25-09-004, which are not expected until Q3/Q4 of 2026. 5. Confirming scope of dual participation policy issues including dual participation with dynamic rates.	N/A

TABLE 4-2
PG&E' RTP REGULATORY ROADMAP FOR POST-PILOT RTP DEPLOYMENT AFTER PG&E'S BILLING MODERNIZATION IS COMPLETED (CONTINUED)

Line No.	Date	Activity	Proceeding	Description/Purpose/Relevance	Decision/Approval Needed
4	By 11/17/25	Motion presenting scheduling proposals for the bifurcated RTP track	A.24-09-014 2023 GRC II ALJ Atamturk Ruling October 9, 2025, OP 3.	A schedule for PG&E's two proposed additional submissions, our January 2026 Stop-Gap Interim RTP Pilot Proposal and our Q3 2027 Updated Supplemental RTP Testimony will be presented in the Motion. Note that this testimony was finalized before the required Motion's proposed scheduling options had been completed.	
5	12/1/25	Reply Comments	R.25-08-004 EDROIR	Same focus as stated in row 3, above.	N/A
6	1/30/26 (Requested)	January 2026 Stop-Gap Interim RTP Pilot Proposal (to extend HFP Pilots)	A.24-09-014 2023 GRC II	First, requests extension of timing and funding for an interim solution that will provide PG&E's customers continued access to RTP between the current end-date for ongoing HFP Pilots (of 12/31/27) and launch in PG&E's modernized billing system (in 2031 or later). Request will include a) Rate Design, b) Proposed Revisions to Dual Participation with DR programs, c) Systems and Processes, d) ME&O plans, e) M&E plans, e) Cost Estimates and Timelines, and f) Funding / Cost Recovery Proposals. Second, provides cost estimates needed for LMS-compliant RTP rates to be available until post-pilot RTP launch in PG&E's modernized billing system, in 2031 or later.	CPUC Decision needed by 11/19/26 in order to implement any changes prior to the current conclusion of the HFP Pilots in December 2027.

TABLE 4-2
PG&E' RTP REGULATORY ROADMAP FOR POST-PILOT RTP DEPLOYMENT AFTER PG&E'S BILLING MODERNIZATION IS COMPLETED (CONTINUED)

Line No.	Date	Activity	Proceeding	Description/Purpose/Relevance	Decision/Approval Needed
7	5/8/26	LMS Compliance Plan Annual Update	CEC's LMS Rulemaking	Make updates to PG&E's current LMS Compliance Plan to incorporate any needed changes based on CPUC regulatory process filings and directives, and pilot learnings (to date).	CEC has discretion on timing of approval of LMS Compliance Plans.
8	Q2 2026 (estimated)	Billing Modernization Decision	A.24-10-14 Billing Modernization Proceeding	Could alter and / or clarify timing for RTP implementation in billing system.	N/A
9	7/1/2026 (estimated - 6 0-120 days prior to being effective)	FERC Filing	FERC Section 205 filing for transmission component proposal	Dynamic Transmission rate component design.	FERC Decision needed by 1/1/27 in order to incorporate into Rate Design by 1/1/28.
10	TBD	Additional EDROIR Filings – TBD	R.25-08-004 EDROIR	TBD in Revised Scoping Memo.	TBD
11	8/1/26 (expected)	HFP Pilots' midterm M&E results	R.22-07-005 DFOIR Track B	Needed insights on load impacts (load shift / load reduction / load growth in beneficial hours) by customer and end-use, and customer feedback on ME&O and Customer Support.	N/A
12	9/30/26 (estimated)	EDROIR Proposed Decision	R.25-08-004 EDROIR	See Row 3, above, for contents.	N/A
13	11/19/26 (requested)	January 2026 Stop-Gap Interim RTP Pilot Proposal Decision	A.24-09-014 2023 GRC II	See Row 6, above, for contents.	CPUC's January 2026 Stop-Gap Interim RTP Pilot Proposal Decision is needed by 11/19/26 for enough time to implement any changes prior to the Expanded HDP Pilots' current end-date in December 2027.

TABLE 4-2
PG&E' RTP REGULATORY ROADMAP FOR POST-PILOT RTP DEPLOYMENT AFTER PG&E'S BILLING MODERNIZATION IS COMPLETED (CONTINUED)

Line No.	Date	Activity	Proceeding	Description/Purpose/Relevance	Decision/Approval Needed
14	Q3 2027 (requested)	Updated Supplemental RTP Testimony	A.24-09-014 2023 GRC II	1. Incorporate any requirements / guidelines from the Decision in the EDROIR into post-pilot RTP deployment plans. 2. Incorporate pilot findings from HFP Pilots' midterm M&E results expected in August 2026 into post-pilot RTP deployment plans. 3. Update interim and post-pilot RTP rate design based on pilot findings, requirements from EDROIR and LMS requirements. 4. Provide cost estimates informed by any guidance from the EDROIR Decision for systems and processes into post-pilot RTP deployment plans. 5. Request funding / cost recovery for post-pilot RTP deployment.	CPUC Decision needed by 12/29/28 to ensure enough time to begin programming in 2030 at the earliest when Billing Modernization is complete in Q4 2029 or later. Time is needed before programming starts to develop business requirements for all impacted systems and collaborate with CCAs.
15	TBD - After Filing of Supplemental RTP Testimony Proposals – Update in Q3 2027	Additional Regulatory Steps	A.24-09-014 2023 GRC II	1. Intervenor Testimony 2. Rebuttal 3. Settlement Discussions on Supplemental RTP Testimony Proposals – Original on 10/29/25 and Update in Q3 2027.	N/A
16	By 1/1/28	Implementation of January 2026 Stop-Gap Interim RTP Pilot Proposal	N/A	Continuing availability of RTP rate for all customers until RTP rates can be launched in PG&E's billing system in 2031 or later.	N/A

TABLE 4-2
PG&E' RTP REGULATORY ROADMAP FOR POST-PILOT RTP DEPLOYMENT AFTER PG&E'S BILLING MODERNIZATION IS COMPLETED (CONTINUED)

Line No.	Date	Activity	Proceeding	Description/Purpose/Relevance	Decision/Approval Needed
17	12/29/28 (requested)	Proposed Decision on both Supplemental RTP Testimony Proposals (10/29/25 and Q3 2027)	A.24-09-014 2023 GRC II	See Lines 2 and 14 for contents.	CPUC Decision needed by 12/29/28 to ensure enough time to begin programming in 2030 at the earliest when Billing Modernization is complete in Q4 2029 or later. Time is needed before programming starts to develop business requirements for all impacted systems and collaborate with CCAs.
18	Q4 2029 (expected)	Billing Modernization Completed		New Integrated Billing System In place.	
19	2030 or later (estimated)	RTP rates programmed in modernized billing system		HFP Pilots continue.	
20	2031 or later (estimated)	RTP rates launched in modernized billing system	N/A	HFP Pilots end.	N/A

(a) See Table 4-1 for specific cost categories that need to be considered for the January 2026 Stop-Gap Interim Pilot Proposal and for post-pilot RTP deployment.

G. Conclusion

PG&E has presented cost categories but was unable to provide cost estimates within the 60-day deadline from D.25-08-049 for preparing this Supplemental RTP Testimony. As described previously, PG&E is in a unique situation not being able to program this type of RTP rate into our Billing System until 2030 or later, with a launch of 2031 or later. Therefore, PG&E's testimony here is presenting an RTP Regulatory Roadmap that includes two-steps in order to allow continuous access to RTP for PG&E's customers before the post-pilot RTP rates can be launched in our Billing System.

PG&E will be filing a Motion by November 17, 2025, presenting our proposed schedule for the Bifurcated RTP Track of this GRC II proceeding that will request an expedited Ruling approving PG&E's RTP Regulatory Roadmap's schedule to include two additional filings, as detailed in Section F above and summarized as follows:[20]

1. Stop-Gap Interim RTP Pilot Testimony – Requested RTP Regulatory Roadmap Timing

a) 1/30/26 – PG&E's Stop-Gap Interim RTP Pilot Proposal to extend our ongoing HFP Pilots beyond their current December 31, 2027 expiration date.

b) 11/19/26 – Requested target date for CPUC issuance of a Final Decision on PG&E's Stop-Gap Interim RTP Pilot Proposal, to provide enough time to make the adopted modifications for the extension of the HFP Pilots beyond December 31, 2027.

2. Updated Supplemental RTP Testimony – Requested RTP Regulatory Roadmap Timing

a) Q3 2027 – PG&E's Updated Supplemental RTP Testimony submitted, using the most informed rate design and Operational Implementation, M&E and ME&O plans as possible incorporating learnings from the HFP Pilots' midterm M&E results expected in August 2026, as well as

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[20] The requested target dates for issuance of CPUC Final Decisions on the January 2026 Stop-Gap Interim RTP Pilot Proposal, the October 2025 Supplemental RTP Testimony, and the Q3 2027 Updated Supplemental RTP Testimony will need to be adjusted based on the CPUC's 2026 Business Meeting schedule where CPUC Decisions are rendered, once that Business Meeting schedule has been issued.

incorporating any guidance from the EDROIR Final Decision expected by the end of 2026.

b) 12/29/28 – Requested target date for CPUC issuance of a separate final Decision, on both this Supplemental RTP Testimony (submitted 10/29/25), and on PG&E's Updated Supplemental RTP Testimony (to be submitted by Q3 2027), to allow enough time to implement the adopted modifications for post-pilot RTP deployment in PG&E's new billing system (BMI). See table 4-2, Line number 14 for more details on the need for this decision timing.

If the CPUC does not approve the January 2026 Stop-Gap Interim Pilot Proposal or the Q3 2027 Updated Supplemental RTP Testimony elements of our RTP Regulatory Roadmap, PG&E requests that the CPUC issue an interim decision: (1) authorizing PG&E to file a Tier II advice letter to continue the HFP pilots after December 31, 2027, until the BMI is completed and RTP rates are built in the billing system, and (2) establishing the schedule and / or proceeding for further testimony on post-pilot RTP rates and related processes and system costs.