Application: 22-05-
(U 39 E)
Exhibit No.: (PG&E-2)
Date: May 2, 2022
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023-2027 DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS

2024-2027 FULL PROPOSAL

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2023-2027 DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS
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A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) is pleased to present its 2024-2027 Demand Response (DR) Application, which builds on the experiences and lessons from PG&E's 2018-2021 DR programs and Emergency Reliability program operations in 2020 and 2021. A central theme of PG&E's proposals is to utilize DR to meet the evolving complexities of grid needs. Over recent years, the State of California has experienced the devastating effects of wildfire, severe drought, prolonged heat storms and global pandemic, all of which have had ramifications on grid reliability. These climate-related conditions are expected to persist, and effective utilization of DR can play a role in mitigating their effect on grid reliability. With these considerations, PG&E proposes to enhance the DR portfolio and DR policy matters in ways that are responsive to both the needs of the grid and participating customers for today and in the future. Specifically, as illustrated in Table 1-1, PG&E proposes to double the size of its demand-side resource portfolio between 2022 and 2027, all the while improving the availability and reliability of its DR capacity.

TABLE 1-1
DEMAND-SIDE RESOURCE PORTFOLIO GROWTH FORECAST

Line No.	Portfolio Forecasted MW 2023-2027 (August Peak)						
1	Year	2022	2023	2024	2025	2026	2027
2	Base Interruptible Program (BIP)	184	252	319	319	319	319
3	Capacity Bidding Program (CBP) – Non-Residential	54	60	69	78	86	95
4	CBP – Residential	4	3	4	4	5	5
5	SmartAC – Switch	21	29	23	20	18	17
	SmartAC – BYOT	16	44	0	0	0	0
6	Automated Response Technology (ART)[a]	0	0	60	75	88	102
7	CPP – SmartRate	2	5	4	4	4	4
8	CPP – Peak Day Pricing	19	20	18	16	14	12
9	Emergency Load Reduction Pilot (ELRP)	195	200	229	280	381	483
10	Other Pilots	0	0	25	25	25	25
11	Total	495	612	752	825	947	1,070

Note: Values in this table have been normalized based on the capacity and/or energy the program, pilot, or rates are estimated to provide. While not litigated in this Application, CPP forecasts are included in this table to provide a complete illustration of PG&E's demand-side growth forecast.

(a) ART [Automated Response Technology] is a new program offering that PG&E is proposing in this Application.

PG&E sees the 2024-2027 funding cycle as a time to test out new concepts and invest in our DR infrastructure, to significantly grow the size and capabilities of our portfolio and prepare PG&E for mass-market DR in the subsequent funding cycle (2028-2032). To effectuate this change, PG&E proposes to invest $791 million over the 2024-2027 period.

First, PG&E proposes significant enhancements to its BIP, CBP, and Automated DR incentive mechanism; it's SmartAC Program would continue to leverage direct load control technology and a new program called the ART would be rolled out to support the enablement of residential smart technologies, such as smart controllable thermostats, batteries and EVs for use in DR and TOU/Load Shifting. These enhancements will bolster PG&E's ability to meet the existing and anticipated grid challenges over the 2024-2027 program cycle. PG&E also proposes to launch new pilots—a Residential Smart Panel Pilot, and an Agricultural DR Pilot—to develop and test new DR program design focusing on customer capabilities, technology response and operational experience around providing multiple grid service opportunities as described below. Lastly, as ordered through the Emergency Reliability Rulemaking Phase 1 Decision (Decision (D.) 21-03-056), PG&E has included a request for funding for the Emergency Load Reduction Program (ELRP) Pilot for 2024 and 2025 and is proposing continuation of ELRP to the end of 2027.

PG&E gained valuable insights on the fluidity of evolving grid needs, primarily the magnitude of the capacity and energy shortfalls during 2020 and 2021. PG&E believes that greater flexibility to modify its programs/pilots over the course of the funding cycle to quickly adapt to evolving grid challenges is required to ensure participating customers are providing load relief when needed the most. To this end, PG&E requests greater flexibility to modify program design and shift funds between budget categories.

PG&E has observed that understanding and measuring customer elasticity (i.e., a customer's willingness and ability to respond to DR event calls, rates, or other signals) is key to effectuating all successful load management efforts. In this application, PG&E proposes several studies designed to enhance common understanding of customer elasticity, and to use insights gained to iteratively improve programs and pilots over the 2024-2027 period and beyond.

Throughout the rest of this chapter, we present PG&E's vision and guiding principles for successfully implementing DR in the 2024-2027 program cycle. Namely that:

- Thoughtful design is required to realize multiple use applications and value stacking that capture additional grid services (including support for localized transmission and distribution needs and emission reduction);
- PG&E sees value in consolidating proceedings that address similar DER and demand-side management topics in order to develop a more comprehensive record and to align stakeholders with the objective and how best to enable, scale and operate;
- DR growth strategies must be assessed in the context of a broader comprehensive load management strategy;
- Reassessment of DR's cost effectiveness protocols will be essential to addressing emerging grid and customer issues;
- Programmatic and budget flexibility will be needed to implement PG&E's vision for the DR Portfolio in 2024-2027;

- PG&E continues to support the Commission's goal of increasing the role of third-party DR providers to give customers choice and flexibility to participate in DR; and
- DR programs and pilots have a role to play in support of the Commission's laudable Environmental and Social Justice (ESJ) goals.

B. Background

As an international leader in advancing solutions to climate change, California's energy markets are dynamic and continue to evolve. Senate Bill (SB) 100 (2018) requires that renewable and greenhouse gas (GHG)-free resources supply 100 percent of electric retail sales in California by 2045. The California Public Utilities Commission (CPUC or Commission) is working to meet the State's building decarbonization goals established pursuant to Assembly Bill 3232. State policies are calling for decarbonization of the transportation sector through electrification,[1] as transportation[2] is the largest source of GHG emissions in California.[3] In addition, PG&E expects electric sales to grow by 68 percent through 2040 as Electric Vehicle (EV) adoption and building electrification drive demand, but the pace of this change will be dependent on policy and customer adoption. Lastly, Diablo Canyon Nuclear Power Plant (Diablo Canyon) will be decommissioned, taking 2.25 gigawatt of GHG-free supply offline by 2025.

This will require PG&E to rely on increasingly clean renewable generation, in place of traditional generation. Renewable generation, however, is more intermittent and less dispatchable, which will also widen the gap between the midday trough (belly of the duck) and evening ramp (neck of the duck), with increased volatility in net loads. These grid challenges are expected to be more

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1 Governor's Executive Order No. B-48-18 (Jan. 26, 2018) calls for at least 250,000 EV charging stations by 2025, and 5 million zero-emission vehicles by 2030, <https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf>, (as of Apr. 21,2022).

2 SB No. 676 (Ch. 484, Stats. 2019) (SB 676) enacted Public Utilities Code Section 740.16, which requires the CPUC to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective EV integration into the electrical grid by January 1, 2030.

3 California Air Resources Board, California GHG Emissions for 2000 to 2018; Trends of Emissions and Other Indicators (2020 Ed.), p. 5, Figure 3, <https://ww2.arb.ca.gov/ghg-inventory-data>, (as of April, 21, 2022).

pronounced over the next 20 years in ways that will be hard to predict, which calls for a broader set of flexible and integrated demand-side solutions that better align with supply, such as load shifting and shaping.

DR programs have existed at PG&E for several decades. Early focus was as an event-based load shedding tool to encourage customers to voluntarily reduce their loads when needed for grid reliability. While the majority of PG&E's DR program portfolio continues to serve reliability purposes, the Commission's decision[4] to bifurcate DR programs into load modifying and supply resources envisioned DR as a more California Independent System Operator (CAISO) market-responsive resource that could be dispatched economically, to receive Resource Adequacy (RA) credit and provide energy.[5] While DR is not the panacea to the grid and environmental challenges the State faces, it does play an important role primarily as one of the signals within an overall load management strategy that customers and third-parties assisting customers can optimize to facilitate the State's abilities to meet its ambitious energy and climate goals.[6]

C. PG&E's Vision and Principles for 2024-2027 Application

PG&E contends that the proposals set forth in this Application set DR on a more effective path to addressing the grid's greatest needs while supporting customers in a manner guided by PG&E's triple bottom line of People, Planet and Prosperity.

People – The privilege PG&E has to serve its customers is not taken for granted and follow through of PG&E's commitment to its customers to provide affordable, reliable, safe, and clean service remains paramount. The proposals

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4 D.14-03-026, p. 28, Ordering Paragraph (OP) 1 ruled that current DR programs be bifurcated into load modifying and supply resources beginning with the 2017 program year.

5 Supply side DR is integrated into the CAISO's market while load modifying DR is not integrated. D.14-12-024, p. 84, OP 4.a ruled that beginning on January 1, 2018, any DR that does not reduce the RA requirement must be integrated into the CAISO market to receive RA value.

6 SB No. 100 titled the "100% Clean Energy Act of 2018" set a goal of 100 percent clean energy by 2045, established a 60 percent Renewable Portfolio System target by 2030, along with other activities to support achievement of SB No. 100. <https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100>, (as of Apr. 21, 2022).

laid forth in this Application enhance PG&E's DR portfolio's ability to support and serve customers by mitigating the effects of capacity and energy shortfalls, minimizing the impacts of Public Safety Power Shutoff (PSPS) events, and giving customers who are willing the ability to participate in supporting the grid.

Planet – The correlation between the grid challenges the State is encountering and the effects of climate change is apparent. While the grid challenges today are front-of-mind, the longer term decarbonization strategy is what will address the climate component of environmental disasters that are plaguing California. DR plays a role in that strategy as a cleaner resource, and its effective utilization will support the State's ability to meet its various energy and environmental goals.

Prosperity – Energy is a key input to the livelihoods of residents and businesses in our community. By meeting the commitment to provide affordable, reliable, safe, and clean service, PG&E supports the continued prosperity of California's communities. Additionally, PG&E shares the Commission's continued commitment to a competitive third-party landscape for DR that enables a diversity of DR suppliers and supports the transformation of the marketplace for DR services and technology in California. Through mitigation of capacity shortfalls, minimizing impacts of PSPS events and the continued growth of the DR ecosystem, the proposals laid forth in this Application acknowledge and promote opportunities for a diversity of DR suppliers to contribute to the state's grid.

More specifically, PG&E proposes the following principles for the 2024-2027 Application.

1. Integrating PG&E's Vision and California Demand Response Policy

PG&E continues to support the DR principles laid out by the CPUC in D.16-09-056.[7] PG&E believes that the near-term focus of DR should be to address California's capacity shortfall and grid reliability issues. In particular, a focus on the critical months, locations, and hours most susceptible to higher demand and/or higher prices on the grid is warranted. For example, on January 11, 2022, the California Energy Commission (CEC) provided updated shortfall forecast needs for September 2022 ranging from 200 megawatts (MW) to 2,400 MW.[8] The forecasted range of MWs that may be needed to support September 2022 is significantly wide, that flexibility and a mechanism to enhance and modify DR programs is essential to meet the anticipated shortfall. The implications of failing to do so are beyond theoretical given the events of August 14 and 15, 2020, when the CAISO issued a Stage 3 Emergency and ordered firm load curtailment,[9] which had not been seen since the Energy Crisis in 2001.

As the Commission reviews PG&E's 2024-2027 DR application, PG&E encourages the Commission keep in mind the most immediate needs of the

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7 D.16-09-056, Section 4.2.2., pp. 45-46. The goal for CPUC-regulated DR programs is "Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost." The CPUC also established the following principles for all DR programs:

- "Demand response shall be flexible and reliable to support renewable integration and emission reductions;
- Demand response shall evolve to complement the continuous changing needs of the grid;
- Demand response customers shall have the right to provide DR through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access;
- Demand response shall be implemented in coordination with rate design;
- Demand response processes shall be transparent; and
- Demand response shall be market-driven leading to a competitive, technology-neutral, open-market in California with a preference for services provided by third-parties through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions."

8 CEC – 21-ESR-01: Staff Paper – Updated 2022 Summer Supply Stack Analysis (January 11, 2022). https://efiling.energy.ca.gov/GetDocument.aspx?tn=241145&DocumentContentId=74989 (as of Apr. 21, 2022).

grid and the timeframes for those needs. The grid is continually evolving and all stakeholders must remain focused on prioritizing and advancing proposals which are directly aligned with addressing the greatest grid needs. Additionally, the Commission should consider relaxing requirements which hinder the ability to grow DR capacity in this time of need.

However, beyond the most urgent issue of capacity and energy shortfalls, the future needs of the grid will require thoughtful design and the ability to realize multiple-use and value stacking to capture additional grid services including support for localized transmission and distribution needs and emission reduction. Enabling customers to provide multiple-use grid services may (1) offer additional value back to participating and non-participating customers and third-party providers, (2) provide PG&E with additional resources to be used to address grid challenges beyond generation capacity and energy, and (3) offer an improved cost-effective program and portfolio solution. PG&E believes that one key area to advance multiple-use is through customer BTM technologies and its ability to be responsive in an automated way that does not burden customers.

California regulatory agencies recognize the potential role of widespread adoption of BTM technologies as a value-added tool to support customers and the grid. As outlined below in Table 1-2, there is much regulatory activity addressing Distributed Energy Resource (DER) technologies and signals such as rates and grid service programs. PG&E recognizes that those parallel efforts will be influential in evolving DR capabilities and applicable use cases. As one example, export of energy from customer BTM DERs to the grid is an opportunity to further develop a firm response from demand to realize a clean energy portfolio. Given the number of proceedings that are addressing the topic of export (e.g., BEV Non- Net Energy Metering (NEM) Export, Summer Reliability – DR ELRP) ensuring alignment and consistent rules with clear directives is critical. PG&E sees value to consolidate proceedings that are addressing similar topics and encourages the Commission to do so, in order to develop a more

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9 CAISO Operating Procedure 4420 – <www.caiso.com/Documents/4420.pdf>, (as of Apr. 21, 2022).

comprehensive record and to align stakeholders with the objective and how best to enable, scale and operate. Such consolidation should help address program misalignments across customer programs and should produce customer offerings that may be easier for the customers to participate in.

TABLE 1-2
DEMAND-SIDE PROCEEDINGS AND INITIATIVES

Line No.	Agency	Proceeding	Summary
1	CEC	Load Management Rulemaking (19-OIR-01)	Pursuing the implementation of hourly and/or sub-hourly energy pricing, including the development of a price dissemination platform.
2	CEC	Flexible Demand Appliance Standards (20-FDAS-01)	Create framework which facilitates the standards that “promote technologies to schedule, shift and curtail appliance operations to support grid reliability, benefit consumers, and reduce GHG emissions associated with electricity generation” in accordance with SB 49.
3	CEC	CalFlexHub	“[C]onduct electricity sector applied research and development and technology demonstration and deployment projects that increase the use and market adoption of advanced, interoperable, and flexible demand technologies […].”[a]
4	CPUC	DER Action Plan 2.0	Final plan adopted during April 21, 2022, Commissioner meeting. Serves as a roadmap to facilitate forward thinking DER policy and coordinate the development and implementation of DER policy. Future Commission action expected.
5	CPUC	General Rate Case (GRC) Phase II (A.19-11-019)	PG&E and Parties' settlement agreement regarding real time pricing (RTP) pilots for Residential and Commercial and Industrial customers to commence by the Fall of 2023, as well as a proposed dynamic pricing rate design and preferences research for the Residential, Small Business and Agricultural customer classes.
6	CPUC	Commercial EV (A.20-10-011)	The CPUC adopted an RTP rate for Business EV customers designed to enable customers to assist in grid management and to further save costs by aligning their charging sessions with periods of reduced energy costs. Non-NEM export compensation to be considered in Phase 2 of this proceeding.
7	CPUC	Vehicle-to-Grid Integration (VGI) (D.20-12-029)	Mandates the implementation of various strategies to maximize VGI by January 1, 2030, in accordance with SB 676.
8	CPUC	Rule 21 Interconnection	Pertains to the way DERs, including solar and storage (stationary and mobile) interconnect with PG&E’s system. Issues surrounding the capabilities of these resource, including exporting back onto the grid, are continuously being evaluated and re-assessed for both safety and functionality.
9	CPUC	DR Potential Study	Phase 4 of the DR Potential Study is underway by Lawrence Berkeley National Lab (LBNL). This phase is looking at a broader set of DER inputs beyond DR (EE, EV, storage) to help inform the four parameters for “shape, shift, shed and shimmy.”

(a) CEC Solicitation GFO-19-309 for Grant Funding Opportunity for the California Flexible Load Research and Deployment Hub (CalFlexHub), Application Manual Addendum, submitted in September 2020, <https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub> (as of Apr. 21, 2022).

2. A Comprehensive Load Management Strategy Is Necessary

PG&E believes the energy market dynamics over the next 10 years will require stronger coordination between supply and demand and a comprehensive load management approach that is based on customers and demand flexibility to ensure reliability and affordability. This includes pricing products to shape loads, energy efficiency (EE) programs to reduce overall kilowatt-hours and peak demand and support electrification, and DR that can provide a wider range of grid services than peak load reduction. PG&E believes comprehensive programs designed to provide EE and DR benefits, combined with the right rate, could have the potential to produce greater value to customers, through greater load impacts at lower cost, than the value of a DR program alone. This type of value stacking is also expected to improve the cost effectiveness of PG&E's demand-side management (DSM) portfolio, but only if it avoids double counting of load impacts and double compensation for the same load reduction.[10] PG&E proposes to enhance the rules that govern how customers can participate in multiple programs to best align with this vision in Exhibit (PG&E-2) Chapter 2, Section C, Dual Participation.

Enabling technologies can also play a significant role, but signals are necessary to trigger not only DR and peak load shaving, but also day-to-day load shaping, shifting, and shedding. For instance, residential DR programs today have been focused on Air Conditioning (A/C) cycling using one- and two-way direct load control switches for primarily emergency DR purposes. In this Application, PG&E proposes to roll out a new offering called the ART Program. ART is an innovative offering for enabling a host of technologies to support residential DR and TOU/Load Shifting. PG&E also proposes to study via pilots and ultimately develop a new whole home program that allows customers to connect smart devices and DERs to provide a comprehensive load management solution that mobilizes a wider range of end-use loads to deliver greater benefits to customers and the grid. On the non-residential side, customers seek solutions to meet their energy goals,

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10 PG&E notes that there may also be interactive effects between certain programs that require coordination (i.e., EE programs can reduce DR potential).

including a climate stance such as GHG reductions. PG&E sees an opportunity to offer customers an integrated approach that combines technology and DR program offering with a pilot like PG&E's proposed Clean Energy Optimization Pilot[11] to not only address grid needs but also GHG reductions. See Exhibit (PG&E-2) Chapter 3 for additional details of PG&E's program proposals, and Exhibit (PG&E-2) Chapter 4 for potential activities under Integrated DSM.

a. Maximizing Load Management Potential Requires Understanding Customer Load Elasticity

PG&E's demand-side programs today are broadly available to large customer segments, but we believe there are greater opportunities to enhance the customer experience with more targeted programs, enabling technology, and enhanced signals that are leveraged to participate in load management programs. This requires better understanding our customers' end-use load elasticity in response to a signal. That end use load elasticity may change during key times of the day, based on their sector/subsector, location, existing enabling technologies, and demographics, as well as other conditions (i.e., temperature, day of week, hour of day, etc.). DR programs, for instance, should focus on maximizing the load shift and reductions of end uses that are elastic during times of greatest grid need and can be firmly delivered. In contrast, end uses that are the least elastic may be better suited for an EE program or supported by BTM energy storage, while customers with highly elastic end uses might be well suited for dynamic rates such as PG&E's upcoming RTP pilots.[12] See Figure 1-1 for our approach to align end use load elasticity to program designs that maximize load management potential at least cost, which will help PG&E prioritize which pilots and programs to pursue to best optimize for grid needs.

11 See PG&E's Prepared Testimony, filed Mar. 4, 2022, in A.22-03-006.

12 See Settlement Agreement in GRC Phase II A.19-11-019 RTP track, Exhibit SP-RTP-1, filed January 14, 2022.

FIGURE 1-1
MAXIMIZING LOAD MANAGEMENT POTENTIAL REQUIRES UNDERSTANDING CUSTOMER LOAD ELASTICITY

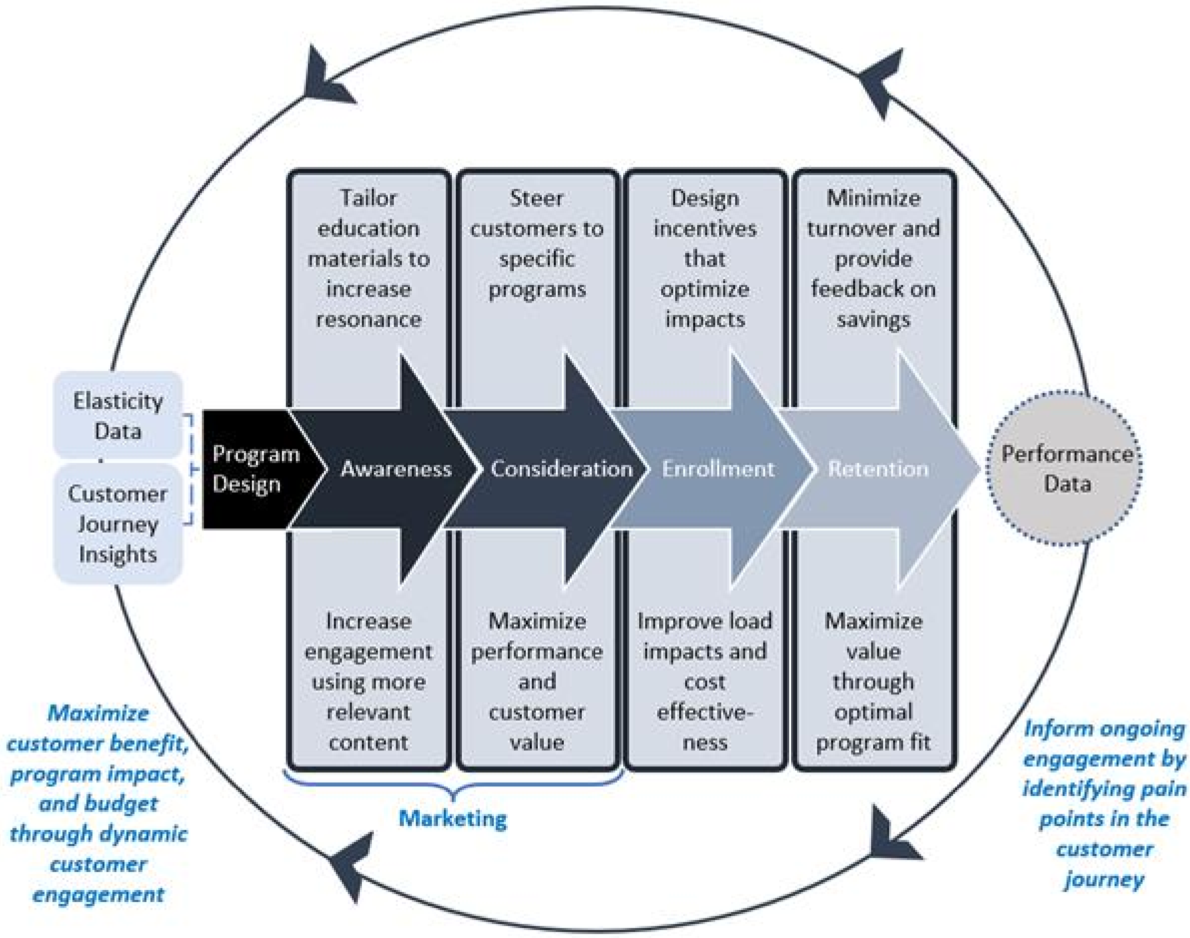
	Elastic (Flexible)	⟷	Inelastic (Rigid)
Maximizing Performance	Utilize more ***pricing programs*** with controls based on preferences	Utilize ***demand response*** targeted to evolving grid needs	Utilize ***energy efficiency*** or mobilize loads with ***storage***
Enrollment	Easiest to enroll and should be targeted with least-cost marketing	Make enrollment easy and flexible by offering multiple program options	Most difficult to enroll; target programs and develop standards
Retention	Easier to retain as elasticity increases over time	Customer education plays a role to avoid customer fatigue	Better suited for one-time actions (e.g., retrofits)
Technology Adoption	Significantly aided by price-responsive automation technologies	Technologies that automatically respond to signals optimize performance	Incentives can drive more efficient and automated device adoption

Load elasticity can also change over time as customers adopt new technologies and automation capabilities, and transition across the elasticity spectrum. See Exhibit (PG&E-2) Chapter 4 to see how PG&E will work with the CEC on a Market Informed Demand Automation Server and load management standards that will develop and test signals and support this transition.

b. Customers are at the Core of Load Management, and Solutions Need to Focus on a Streamlined Customer Experience Across Different Demand-Side Solutions

A positive customer experience is at the core of PG&E's load management strategy. PG&E believes customer elasticity data should be used to inform specific aspects of program design and enhance the customer experience. Instead of offering a broad set of programs, rates, and technology incentives that largely operate in siloes and meet a disparate set of needs or goals, we want to transition to a set of load management programs that are based on specific tactics, embed technology incentives, and provide a broader set of benefits. As described in Exhibit (PG&E-2) Chapter 3, Section G.3, PG&E intends to create an online platform that will provide an overview of the DR programs currently available to residential customers. Based on PG&E data and information provided by the customer, the platform will provide tailored guidance across PG&E offerings including but not limited to DR programs, incentives and tools related to other demand side management opportunities in energy-efficiency, EVs, distributed generation and resiliency. We believe this approach allows customers to learn about specific tactics that are actionable and maximize value. See Figure 1-2 for how such an approach can be used iteratively to improve program design and enhance the customer journey.

FIGURE 1-2
ELASTICITY DATA SHOULD INFORM PROGRAM DESIGN AND THE CUSTOMER JOURNEY



For example, PG&E proposes in Exhibit (PG&E-2) Chapter 4 to develop a new DR pilot for agricultural customers that is based on their unique capabilities (and challenges), with targeted outreach and engagement throughout a customer's pilot participation, while simplifying enrollment and disenrollment processes. And PG&E's Residential Smart Panel Pilot, described in Exhibit (PG&E-2) Chapter 4, will seek to orchestrate multiple loads with one central technology to achieve the customer's energy goals which may include maximizing bill savings, minimizing discomfort, reducing overall energy consumption, and participating in DR.

c. More Data is Needed on Load Flexibility and Elasticity to Meet Evolving Grid Needs

Today there is limited data on customer end-use loads and elasticity of that load over specific times of day, especially as customers adopt newer technologies and BTM resources. PG&E proposes to conduct a new load flexibility study, as described in Exhibit (PG&E-2) Chapter 2. The main purpose of this study is to leverage existing and new pilots to identify and disaggregate end-use loads that are sizeable and flexible enough to help address operational and planning needs, and determine if these loads can be managed through existing programs or, if not, through modified and new pilots and programs that can be deployed as soon as possible. While certain aspects of this study are like the DR Potential Studies conducted by LBNL as a part of prior DR proceedings, PG&E, in collaboration with the other Investor-Owned Utilities (IOU), seeks greater granularity and quality of the underlying load disaggregation data, broader valuation of benefits in the context of a comprehensive load management strategy, and actionable recommendations that improve the customer experience and maximize participation.

In addition, part of aligning our customer capabilities to growing our DR portfolio is tied to RA requirements and how DR-backed RA resources are counted and shown. PG&E believes the "slice-of-day" reform being discussed in the RA proceeding (Rulemaking (R.) 21-10-002) may lead to shorter RA showing periods (i.e., allow for greater use of pre-cooling to maintain comfort during shorter DR events), which is expected to unlock more DR capacity than can be currently available with a four-hour minimum dispatch requirement. PG&E also believes that a comprehensive review of the efficacy of DR market integration is warranted at this time. As described in Exhibit (PG&E-2) Chapter 2, PG&E proposes the IOUs hire a consultant to conduct a study akin to LBNL DR Potential Study and form an advisory board which will include the CPUC, CAISO and CEC to take place over the 2024-2027 period.

3. Reassessment of Cost-Effectiveness Is Necessary to Meet Evolving Grid Needs

To meet evolving grid needs, PG&E needs the flexibility to initiate new programs. A key component of this flexibility will be enabled by the reform of DR's cost-effectiveness protocols. Currently, DR programs are required to undergo a cost-effectiveness assessment under the 2016 DR Cost Effectiveness Protocols (2016 Protocols).[13] However, these protocols have not been updated since 2016 despite continual updates to the Avoided Cost Calculator (ACC), which has created a divergence in the proxy generation resource used for measuring cost-effectiveness.[14] In the years since DR programs were market integrated, PG&E has observed that many of the assumptions and methodology buttressing the 2016 Protocols do not fully account for the value and impact DR resources can and do have on the grid. Therefore, PG&E recommends that the Commission evaluate the efficacy of the 2016 Protocols to determine their continued relevance and effectiveness.

4. Programmatic and Budget Flexibility Is Needed to Implement PG&E's Demand Response Portfolio

Flexibility in the programmatic and budgetary frameworks are needed for PG&E to effectively meet evolving grid needs—particularly immediate, short-term needs. The Commission opened R.20-11-003 to address 2021-2023 summer reliability challenges. The proceeding allowed the IOUs to expeditiously submit proposals to enhance its DR programs outside of the DR funding application cycles. While PG&E supports the intent and the need for institution of new Rulemakings, new proceedings may not always be the nimblest manner to quicky address changing grid conditions. As detailed in Exhibit (PG&E-2) Chapters 2 and 8, PG&E requests regulatory channel that allow for the expeditious review and approval of future program

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13 2016 DR Cost Effectiveness Protocols dated July 2016, p. 7. <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness>, (as of Apr. 21, 2022).

14 D.16-06-007 adopted annual updates to the ACC, and D.19-05-019 adopted a schedule for both major and minor changes to the ACC, with minor changes occurring in odd-numbered years by Staff-initiated Resolution.

enhancements and new pilots for the purposes of addressing reliability and meet evolving grid needs.

The current limitations on shifting funds both within and across funding categories have also been a barrier for PG&E to expeditiously implement enhancements to its DR offerings. PG&E requests more flexibility in using authorized funds across differing categories. As described in Exhibit (PG&E-2) Chapter 8, this flexibility could be in the form of converting the Tier 3 advice filing to a Tier 2 for fund-shifting across budget categories.[15]

5. Continue to Support Provider Diversity

PG&E is committed to supporting the Commission's goal of increasing the role of third-party DR providers to give customers choice and flexibility to participate in DR and the use of data platforms to facilitate customer authorizations and participation. PG&E enables retail customer participation with third-party DR providers through the data and other platforms enabled by Electric Rule 24. There has been a significant growth in the participation in Rule 24 customer authorizations and registrations in the CAISO since approval of the 2018-2022 DR Application. As described in Exhibit (PG&E-1) Chapter 2 and Exhibit (PG&E-2) Chapter 5, PG&E anticipates continued growth as the third-party DR marketplace continues to develop and mature.[16] While the primary driver for the growth in Rule 24 DR participation has historically been from the Demand Response Auction Mechanism (DRAM) pilot, PG&E has observed a shift toward other growth drivers in non-DRAM and non-IOU Load Serving Entity programs and procurement. Therefore, PG&E is continuing to propose appropriate funding to support scaling growth in retail customers' participation in the CAISO market with third-party DR providers.[17]

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[15] D.20-05-009 enabled the Utilities to request for fund-shifting <u>between</u> DR budget categories through a Tier 3 Advice Letter (AL).

[16] See Exhibit (PG&E-1) Chapter 2 and Exhibit (PG&E-2) Chapter 5 for additional details on the expected growth.

[17] See Exhibit (PG&E-1) Chapter 2 and Exhibit (PG&E-2) Chapter 6, Part C addresses the scaling needs to support third-party DR.

6. Demand Response Support for Environmental and Social Justice

The Commission defines ESJ as "ESJ seeks to come to terms with, and remedy, a history of unfair treatment of communities, predominantly communities of people of color and/or low-income residents. These communities have been subjected to disproportionate impacts from one or more environmental hazards, socioeconomic burdens, or both."[18]

In the Commission's ESJ Action plan draft issued October 21, 2021,[19] PG&E identified several ESJ goals that it intends to support enterprise wide. DR programs and pilots can support many of the Commission's ESJ goals, which are discussed below.

- <u>Goal 1</u>: Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health.

  DR programs and pilots are a source of clean capacity and energy resources that support grid needs across all communities. Specifically, for ESJ communities, which can include Disadvantaged Communities (DAC) and income-qualified residents, DR programs and pilots offer both financial benefits through enrollment/participation as well as the ability to improve local air quality through the potential reduction of the use of peaker generation facilities that often rely on fossil fuels. Such facilities tend to be frequently located in ESJ communities, such as DACs.[20]

- <u>Goal 2</u>: Increase climate resiliency in ESJ communities.

  DR programs and pilots support evolving grid needs driven partly by climate change. As weather and temperature extremes continue to impact the grid, DR programs and pilots help mitigate these stressors by helping to reduce or shift load during critical periods. Consequently, DR

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18 D.21-06-015, Section 9, pp. 405-407. A.20-10-006, p. 13.

19 CPUC, "*Environmental and Social Justice Action Plan, Version 2.0*, (Draft version for public comment), (Oct. 26, 2021), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/draft-cpuc-esj-2010262021c.pdf>, as of Apr. 21, 2022).

20 Approximately 50 percent of peaker facilities are in DACs, PSE Health Energy, California Peaker Power Plants, Energy Storage Replacement Opportunities, (May 2020), <https://www.psehealthyenergy.org/wp-content/uploads/2020/05/California.pdf>, (as of Apr. 21, 2022).

programs and pilots can help to both: (1) reduce air pollution through minimizing reliance on peaker facilities, and (2) reduce the possibility of service curtailment (e.g., rolling black-outs and/or distribution overload).

- Goal 3: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs.

  Multiple stakeholders including those representing environment justice organizations are active in the DR space. Their input is considered as part of the overall public policy deliberation at the CPUC. Moreover, PG&E engages directly with ESJ stakeholders regarding areas of mutual interest and potential collaboration. It should be noted that PG&E undertook a DAC DR pilot as part of its 2018-2022 DR funding cycle.[21] The pilot carried out in the Fresno area provided useful insight on both the recruitment process and participation of customers located in DACs.[22] See Exhibit (PG&E-2) chapter 2, Section H for additional details on this pilot.

- Goal 4: Enhance enforcement to ensure safety and consumer protection for all, especially for ESJ communities.

  PG&E's DR program tariffs and pilots document the terms and conditions for participation, and are generally publicly available either through PG&E's webpage or that of pilot partners. Tariffed programs must be approved by the CPUC while pilot terms and conditions are either vetted/reviewed or approved by the CPUC.

D. Summary of Proposed Testimony

- **Chapter 2 – Program Policy Enhancements:** This chapter enumerates PG&E's view of current policies, and proposes changes and new studies for addressing DR development.
- **Chapter 3 – 2024-2027 Demand Response Programs Proposals:** This chapter describes PG&E's proposed improvements to its existing DR programs and a new DR program for the 2024-2027 DR program cycle.

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21 PG&E AL 5477-E, filed February 8, 2018 and 5477-E-A, filed May 7, 2019).

22 Fresno Energy Program, <https://www.fresnoenergyprogram.com/>, (as of Apr. 21, 2022).

- **Chapter 4 – 2024-2027 Demand Response Technology Programs, Pilots And Load Management Proposal:** This chapter describes PG&E's proposals for new and existing Pilots, continuation of DR technology programs and supporting Load Management activities for the 2024-2027 DR program cycle.
- **Chapter 5 – Third Party Demand Response:** This chapter discusses PG&E's assessment of the future of The RAM, pathways for participation, and opportunities for third-party DR providers.
- **Chapter 6 – Demand Response Operations:** This chapter describes the activities that support 2024-2027 DR program operations. These activities include the operation and maintenance of DR-related systems that support online enrollment, curtailment event notifications, energy management applications, and DR event reporting. DR Operations also supports wholesale market integration, third-party participation, and expanded customer choices for DR participation. As part of this chapter, the scaling of Rule 24 capabilities including Share My Data are addressed.
- **Chapter 7 – Load Impacts, Measurement, And Evaluation:** This chapter describes the Load Impact estimates and Measurement and Evaluation activities of PG&E's 2024-2027 DR portfolio.
- **Chapter 8 – Proposed And Alternative Demand Response Budget Request:** This chapter presents PG&E's proposed budget forecast for the 2024-2027 DR program cycle, as well as an alternative budget. It also contains proposals for fund-shifting rules and seeks flexibility to modify its 2024-2027 DR programs to reflect updated information and analyses regarding the relative cost and benefits of the DR programs.
- **Chapter 9 – Cost Effectiveness Evaluation:** This chapter presents cost-effectiveness results of the 2024-2027 DR portfolio proposed programs consistent with the protocols adopted in D.10-12-024 and revised in D.15-11-042, as reflected in the 2016 DR Cost Effectiveness Protocols.
- **Chapter 10 – Cost Recovery And Revenue Requirements:** This chapter presents PG&E's proposal for cost recovery of operating expenses and the associated revenue requirements needed to continue operating DR programs and activities for the 2024-2027 DR program cycle. This includes

the continued use of the Demand Response Expenditure Balancing Account to record revenue requirements and actual expenses.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

PROGRAM POLICY ENHANCEMENTS

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A. Introduction

The marketplace for Distributed Energy Resources (DER)[1] and smart appliances continues down the path of maturity with customer options and adoption becoming more widespread. Customers, now more than ever, have access and interest in procuring behind-the-meter (BTM) enabling technologies, which has intended and unintended ramifications on energy usage behaviors. Increased adoption also presents an opportunity to utilize these existing enabling technologies to support grid needs while compensating customers for the grid services they provide. Motivation for customer adoption includes convenience and comfort provided by technology, bill savings, and/or increased resiliency when grid is facing uncertainty to deliver reliable electricity.

Forward thinking and proactive program design must anticipate customers' likely responses and behaviors with and without automated response coming from customer's DER and smart appliances. Therefore, programs must be designed to recognize the customer's capabilities and whether such actions can help address the needs of the grid. Over the 2018-2022 period Pacific Gas and Electric Company (PG&E) has observed that understanding and measuring *customer elasticity* (i.e., a customer's willingness and ability to respond to Demand Response (DR) event calls, rates, or other signals) is key to effectuating all successful load management efforts. For the 2024-2027 program cycle, PG&E believes that customer elasticity should be the primary driver for understanding DR potential for flexible loads, value streams, in program and customer journey designs, and for designing effective DR program growth strategies. Customer elasticity should also be a key input to assessing the efficacy of the market integration model for DR.

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[1] DERs: Include distributed renewable generation resources, energy efficiency (EE), energy storage, electric vehicles (EV), time variant and dynamic rates, flexible load management, and demand response technologies. Most DERs are connected to the distribution grid behind the customer's meter, and some are connected in front of the customer's meter.

The opportunities to leverage customer BTM DER and smart appliance technologies for DR at scale are still nascent, and therefore as part of Rulemaking (R.) 20-11-003, the focus towards enabling DER under a pilot program like the Emergency Load Reduction Program (ELRP) (e.g., subgroup A4 – Virtual Power Plant, and subgroup A-5 Vehicle-Grid-Integration) is warranted to evaluate the efficacy coming from DERs, especially amid needing reliable responsive load to help with summer reliability issues. In addition to the ELRP, PG&E is proposing a new offering called the Automated Response Technology Program, which will leverage residential smart technologies such as batteries and EVs for DR and time-of-use (TOU)/Load Shifting.

In this chapter, PG&E will lay out the policy issues we believe should be addressed in order to leverage customer's willingness and ability to respond to DR event calls, rates, or other signals, towards achieving the growth in DR we envision. The outline of this chapter and summaries of PG&E's recommendations may be found in Table 2-1 below.

TABLE 2-1
SUMMARY OF POLICY PROPOSALS

Line No	Section	Proposal	Customer/Grid Benefit
1	B – Policy Gaps Lead to Divergence Between Technical Potential and Programmatic Potential	Supports undertaking two studies to support and make the Lawrence Berkeley National Laboratory (LBNL) DR Potential Study actionable. Study includes: (1) Load Flexibility Study, and (2) a Market Integration Efficacy Study. Proposes a separate Market Potential Study to increase DR enrollment in distribution and transmission constrained areas.	These two studies would assist in better understanding end-use loads and help evaluate the efficacy of California Independent System Operator (CAISO) market integration for DR programs. Insights gained from the proposed Market Potential Study will shape enrollment strategies by targeting high impact areas to achieve better cost effectiveness.
2	C – Auto Enrollment of Participants Receiving Technology Program Incentives	Require DR participation from customers that receive technology incentives from other customer programs such as EE, Clean Electric Transportation, and Distributed Generation – Self-Generation Incentive Program (SGIP).	Expanded DR participation requirements increases customer enrollment and megawatts (MW) into DR, which increases the ability to support grid needs. Mandatory directives issued by the California Public Utilities Commission (CPUC or Commission) may also lower marketing and customer acquisition cost, thus improving overall cost-effectiveness.
3	D – Dual Participation	Revisit the current dual participation rules through a collaborative stakeholder process.	Improvements to dual participation rules may help to increase DR participation, equitable compensation and help to better measure overall DR performance. Strive towards multi-use and value stacking.
4	E – Prohibited Resources (PR)	Several actions are advanced, including: (1) clarity around the permanent framework for PR compliance, (2) CPUC advancement of a working group to develop fuel switching standards, (3) providing an exemption to the PR mandate for the Base Interruptible Program (BIP) Program.	Greater clarity around the PR compliance framework and flexibility for fuel switching would help investor-owned utilities (IOU) and participants plan for the future. As it relates to exempting BIP, it would potentially increase enrollment and/or availability to support heightened grid needs for the next few years.
5	F – Emergency DR Cap	Proposes to tie the sunset of the 3 percent reliability cap to any extension of ELRP beyond its current expiration.	Enables additional resources to participate in BIP if the ELRP is extended beyond 2025.
6	G – Program Enhancement Flexibility	Request to make ongoing yearly refinements to DR programs via a Tier 2 Advice Filing.	Enables tweaks and pivoting to better address evolving needs during the 2024-2027 period.
7	H – Report Summaries	To provide a summary of the Retail Baseline Working Group (RBWG) and the outcome of the Disadvantaged Communities (DAC) DR Pilot.	The RBWG re-assess the current baseline framework to ensure its efficacy; the DAC DR Pilot evaluated participation dynamics of participants in Fresno DAC areas.

B. Policy Gaps Lead to Divergence Between Technical Potential and Programmatic Potential

LBNL has been engaged in a long-term research effort (DR Potential Study) to evaluate the technical DR potential in California. Phase 1 and Phase 2 of the DR Potential Study introduced a simplified framework for describing the DR resource in four categories of service: Shape, Shift, Shed, and Shimmy. Today's DR resources almost universally fall into the Shed category, with customers curtailing their loads to provide peak capacity reduction "…in emergency or contingency events… ."[2] Shift is a new DR program service concept, which "encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of VRE [variable renewable energy] generation."[3] Phase 3 of the DR Potential Study focused on providing data-driven insights into how California might use Shift DR in meeting its resource planning needs and operational requirements. Phase 4 of the study, focused on a broader set of DERs than just DR, is currently underway with findings expected toward the end of 2022.

Phase 3 of the DR Potential Study identified limiting factors to the growth of Shift resources in California. Among the factors identified in the study are: (1) *Technology Performance*—load that can be shifted, and the duration over which shift can occur, for a particular piece of enabling technology;[4] and (2) *Customer Participation Rates*—the fraction of customers who choose to participate in a DR program.[5] PG&E's own experience with working with emerging DR technologies and enrolling customers into DR programs aligns with the challenges outlined by the Phase 3 study. PG&E's observation is that while the DR Potential Study provides for an informative range of possibilities, it represents theoretical "potentials" that may not be easily supportable with the

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2 The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resources through 2030, (July 14, 2020), p. 1, <https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf>, (as of Apr. 21, 2022).

3 *Id.*

4 The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resources through 2030, (July 14 2020), p. 58, < https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf >.

5 *Id.*

current DR framework that historically has been predicated on load shedding as the primary focus. Phase 3 of the DR Potential Study includes analysis comparing the technical potential of shift resources against programmatic potential the potential after consideration of limiting factors. The gap between the technical potential and more programmatic potential is significant.[6] In PG&E's view, the following challenges related to customer participation in DR are the current limiters to the programmatic potential and would need to be addressed in order to narrow the gap between the technical and programmatic potentials. PG&E is proposing three new studies below to address and complement the current LBNL study.

1. Load Flexibility Study

The DR Potential Study provided for an informative range of possibilities, but only represents theoretical "potentials" that were not easily supportable with the current DR framework that historically has been predicated on load shedding as the primary focus. To develop more actionable insights, PG&E believes that a new load flexibility study should begin in 2024 and continue to be refined and analyzed more granularly through 2027. The main purpose of this study is to identify and disaggregate end-use loads that are sizeable and flexible enough to help address operational and planning needs, and to determine if these loads can be managed through existing programs or, if not, through new or enhance programs. Specifically, this study seeks to accomplish the following:

- Understand PG&E customer elasticity by end-use, by comparing disaggregated load data relative to changes in price, as a function of customer sector, locations, hour of day/day of week, use of automation/technology, historical EE upgrades, temperature, trailing consumption, historical demand, and other exogenous variables;
- Identify usage patterns of specific BTM DER and smart appliances that can help improve customer load elasticity;

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[6] The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resources through 2030, (July 14 2020), Figure 3-16, <https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf>, (as of Apr. 21, 2022).

- Determine how the load-reduction and flexibility potential of these devices could be optimally leveraged via the strategic deployment of BTM DER and smart appliances enabling technology;
- Develop a supply curve of end-use loads that can be leveraged at each hour of the peak; and
- Convert learnings into actionable program design and/or operational insights.

Such a study will require a broad data set that PG&E will develop through its pilots, including those described within this testimony and other PG&E pilots, such as the Real-Time Pricing (RTP) pilots proposed in Application (A.) 19-11-015 and approved in A.20-10-011. While PG&E plans to build upon data provided in prior DR potential studies performed by LBNL, PG&E seeks to differentiate this study by developing actional tactics that extend beyond DR to include other load management solutions; better understand the relationship between incentive levels (both for enabling technology and technology incentives and ongoing incentive payments based on performance), participation, and load impacts; and identify additional value streams.

This type of study requires transparency with customers and/or aggregators engaging in active decision-making relative to prices and signals. It also requires a substantial sample group to draw conclusions from and sufficient price volatility to identify a response to a signal, as well as an understanding that participants in these pilots may be self-selected as having more elastic loads than the population of PG&E customers.

Given the large volume of data and complex analysis required to complete this study, PG&E proposes that this study be conducted and funded in conjunction with California's other IOUs. Using the DR Potential Study as a guide, PG&E assumes the total cost of this study will approach $3 million. PG&E requests $1.2 million (40 percent of the $3 million total costs), to be funded via its DR Emerging Technology Program.[7]

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7 This assumes the remaining $1.8 million is approved in the other IOU 2023-2027 DR Applications.

2. Market Integration Efficacy Study

PG&E recognizes that Commission policy over the past decade has been focused on DR market integration into the CAISO market. In Decision (D.) 14-03-026, the Commission bifurcated DR resources into supply-side DR resources (e.g., resources bid into the CAISO wholesale energy market) and load-modifying DR resources (e.g., resources reshape or reduce the net load curve).[8] Several months later the Commission issued D.14-12-024 which mandates that event based DR programs shall be integrated into the CAISO market in order to maintain Resource Adequacy (RA) value, and required full implementation of bifurcated DR to begin January 1, 2018.[9]

Beginning in 2018, the customers in PG&E's Base Interruptible Program (BIP), Capacity Bidding Program (CBP), and SmartAC™[10] programs were registered at the CAISO such that they are able to be dispatched as Supply Resource DR. As PG&E gains further experience with integrating and operating DR programs in the CAISO wholesale energy market, several significant issues with this approach have become clear. For instance, integrating DR into the CAISO market has been challenging due to existing RA supply plan rules, which were designed for conventional generation resources. Although CAISO and the Commission have done an admirable job of creating initiatives and modifying certain policies and rules to better support DR market integration, there are still gaps.

PG&E advocates rethinking or significantly improving the market integration paradigm for DR and to achieve the goals set forth in the DR Order Instituting Rulemaking (OIR).[11] Specifically, PG&E recommends that

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8 D.14-03-026, p. 28, Ordering Paragraph, (OP) 1.

9 D.14-12-024, pp. 84-85, OP 4.

10 The name SmartAC or SmartRate is a registered trademark of PG&E. All further references to the program in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

11 A Southern California Edison's (SCE) September 2021 policy paper titled "Mind the Gap – Policies for California's Countdown to 2030" identifies non-market integration for programs as a possible pathway for diversifying the DR portfolio, [Mind the Gap | Edison International](https://www.edison.com/home/our-perspective/mind-the-gap.html?msclkid=6d70bbb2c64d11ec9e131657bd4d9511) < https://www.edison.com/home/our-perspective/mind-the-gap.html?msclkid=6d70bbb2c64d11ec9e131657bd4d9511 >.

the Commission initiate a large-scale study to determine whether DR market integration is a more effective mechanism to support the state of California's clean energy policy, whether the Commission's goals for DR market integration have been achieved, and what changes to policies, rules, or processes should occur to make DR a more useful resource. This study would be modeled after the recent large-scale Demand Response Potential Study that was initiated in 2014, and co-funded by the three IOUs. PG&E estimates this study will cost approximately $3 million to engage a consultant to design and manage the study, compile data, interview stakeholders as necessary, and prepare recommendations. PG&E also proposes an Advisory Committee (representing IOUs, the Commission, CAISO, California Energy Commission, and other stakeholders as appropriate) would provide input on the study's direction and serve as contacts for the consultants to request data.

Because the study should inform the IOUs' next DR applications (2028-2032 cycle), the study should conclude no later than mid-2026. PG&E proposes that this study be conducted and funded in conjunction with California's other IOUs. Using the DR Potential Study as a guide, PG&E assumes the total cost of this study will approach $3 million. PG&E requests $1.2 million (40 percent of the $3 million total costs),[12] to be funded via its DR Emerging Technology Program.

3. Market Potential Study

As described in Chapter 9, PG&E seeks to increase DR enrollment in distribution and transmission constrained areas. We propose a Market Potential Study to identify DR capacity potential in transmission and distribution constrained areas. Study findings will shape enrollment strategies by targeting high impact areas to achieve better cost effectiveness. This study will be funded via PG&E's Measurement and Evaluation activities budget.

C. Dual Participation

There is a long history of dual participation rules that provide a regulatory foundation for why dual participation rules are necessary; however, existing dual

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[12] The remainder to be funded by SCE and San Diego Gas & Electric Company (SDG&E).

participation rules are neither complete nor contemplate increasing complexity. As the number of non-IOU DR providers in the marketplace continue to increase, customers and DR providers are increasingly experiencing these complexities firsthand. While the general principles of avoiding double counting and double compensation are reasonable and appropriate, the CPUC's DR dual participation rules were developed in the context of load-modifying DR programs. As program design is shifting to market-integrated DR, including the CAISO's governance of additional dual participation rules,[13] it is reasonable to consider how CPUC dual participation rules should be revised.

PG&E believes revision of the dual participation rules are ripe for discussion through a workshop early in this application proceeding. Such workshops could help stakeholders develop a common understanding of existing CPUC and CAISO dual participation rules and policies and can initiate the establishment of principals and goals for dual participation.[14] For instance, CPUC dual participation rules categorizing programs as event-based and non-event-based are not intuitive and do not resonate with the complexity of a broader range of load management efforts. Similarly, the CPUC dual participation rules only permit dual participation between a capacity program and an energy program and between a day-ahead triggered program and a day-of triggered program, even though dual participation in two of the same types of programs may represent incremental capacity. PG&E proposes to eliminate these two rules and replace them with alternatives discussed below.

Outside of DR, the CPUC has issued incrementality rules in the Energy Storage OIR that consider multiple use applications of the same storage

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13 Including: (a) settlement rules that prohibit Net Energy Metering exports from being counted, (b) prohibition of a customer location to be included in more than one aggregation at a given time, and (c) prohibition of dual participation between DR and the DER Provider Agreement. CAISO Corporation Fifth Replacement FERC Electric Tariff, (Open Access Transmission Tariff) Effective as of April 1, 2022, Section 4.17.3(b-d), Section 4.5.1.1.3, <http://www.caiso.com/Documents/Conformed-Tariff-as-of-Apr1-2022.pdf>, (as of Apr. 21, 2022). CAISO Business Practice Manual for Demand Response, Version 7, Date: May 1, 2021, p. 13, https://bpmcm.caiso.com/BPM%20Document%20Library/Demand%20Response/BPM_for_Demand_Response_V7.docx, (as of Apr. 21, 2022).

14 A workshop may also be helpful in navigating the complexity of dual participation with Community Choice Aggregator (CCA) programs, from applicability of dual participation rules to CCAs to the transparency necessary for IOU administration and enforcement.

resource.[15] While that has been challenging to implement in the context of technology neutral DR programs, many of these principles are reasonable and should be adopted for DR. Further, dual participation between DR and dynamic rates and EE pay-for-performance programs should be thoughtfully considered with a streamlined set of rules to ensure consistency in application across load management-related proceedings.

PG&E believes there are core principles of dual participation that should remain to protect ratepayers, including prohibiting double payment for a single instance of load reduction, avoiding conflicting signals, and ensuring accurate load impact (LI) measurement and attribution issues. Other principles should be replaced with the following:

- Dually-participating programs must be able to be measured and incentivized independently and distinctly from each other to ensure accurate forecasting and counting, which is integral to resource planning, bidding of DR into the CAISO market, cost effectiveness assessment, etc. In order to achieve this, PG&E requires transparency (i.e., within aggregations of customers with third-party providers, with CCA programs, etc.), systems, and processes that can track participation in conflicting programs and address double payment;
- Pilots should generally test one variable at a time and not be permitted to dual-participate with other pilots or programs to ensure proper evaluation of the pilot's merits and to develop systems and processes that can properly separate LIs and payments if the pilot is successful and appropriate for dual participation with other programs; and
- Lastly, program design should be thoughtfully considered to enable greater dual participation across load management strategies.

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15 In its Energy Storage OIR decision (D.18-01-003), the CPUC adopted 11 rules to guide the formation of multiple use applications for energy storage. These 11 "interim" rules are found in Appendix A of the decision, and are summarized here: the location of where resources are interconnected defines what domain they may provide services in (Rules 1-4); reliability service must have priority, must be distinct from the portion of capacity used to perform other services, and cannot be dually committed in such a way that precludes participation in the other reliability services (Rules 5-7); there must be enforcement of rules, availability and performance requirements, and penalties for non-performance (Rules 8 and 10); the storage provider is required to provide transparency to the utility of additional services it provides to others (Rule 9); and compensation and credit may only be permitted for those services which are incremental or distinct, measurable, and counted once to avoid double compensation (Rule 11).

D. Auto Enrollment of Participants Receiving Technology Program Incentives

Customers participating in the Automated Demand Response (ADR) (discussed in detail in Exhibit (PG&E-2) Chapter 4) are required to join a DR program as a condition of receiving technology incentives to offset ADR control costs. Similarly in SGIP proceeding, the Commission now requires customers receiving SGIP Heat Pump Water Heater incentives to enroll in a qualified DR program for a minimum of three years.[16] PG&E believes that such mandates to participate in a DR program are critical to unlocking flexible BTM DERs and smart appliances. PG&E proposes that the Commission develop similar requirements for customers receiving other ratepayer-funded technology incentives, such as those available via EE, Clean Energy Transportation and Distributed Generation. PG&E believes this approach may improve overall cost-effectiveness, grow overall MWs, lower customer acquisition and might provide additional tools to grid operators.

E. Prohibited Resources

PG&E proposes the temporary suspension of the PR restrictions for customers participating in BIP, which is a reliability program (i.e., RDRR in CAISO market), between 2024 and 2027. PG&E believes that a removal of PR restrictions could increase the availability of emergency resources needed to help stabilize the grid and minimize the likelihood of rotating outages during extreme weather events.

1. Regulatory Background

The CPUC has limited the ability to utilize PRs (fossil fueled back-up generation) since 2019. The original framework for the prohibition was set forth in D.16-09-056.[17] Ultimately, the CPUC issued Resolution (Res.) E-4906, which modified in part Res.E-4838. Moreover, the original

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16 D.22-04-036,pp. 105-108.

17 D.16-09-056, OP 2-5.

list of PRs, and those which were exempt, was updated through D.18-06-012.[18]

Res.E-4906 set forth the compliance mechanism for limiting the use of PRs and clarified the two types of violations.[19] Furthermore, Res.E-4906 created a number of implementation activities, including: (1) updates to tariffs for the inclusion of language pertaining to restrictions and related attestations by DR participants,[20] (2) an outreach plan to participants,[21] and (3) update of the verification plan for monitoring compliance by an independent Verification Administrator (VA).[22] Lastly, PG&E was authorized to shift funds to cover the cost of the VA and for system updates but chose not to do so at the time.[23]

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18 D.18-06-012, p. 20, OP 3 added "energy storage resources not coupled with fossil-fueled generation" to the technologies exempted from the prohibition. The exemption for pressure reduction turbines and waste-heat-to-power bottoming cycle Combined Heat and Power (CHP) was retained. The original prohibition stood for distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping cycle CHP or non-CHP configuration.

19 Violations fall into one of two categories. Type 1 violations are "minor clerical or administrative errors" that can be resolved with an updated attestation. Type 1 violations must be cured within 60 days otherwise the participant can be removed from the DR program. Type 2 violations are serious in nature and can be related to use of a PR "despite attesting to not doing so" or providing "an invalid nameplate capacity." A Type 2 violation would result in the removal from a DR program for a year. Subsequent Type 2 violations would bar a participant for three years.

20 Advice Letter (AL) 4991-E-C filed July 23, 2018, updated the BIP and CBP tariffs, including the program tariffs, Add/Delete Forms and related Aggregator Agreements.

21 AL 5334-E filed July 23, 2018 specified an outreach plan including three outreaches to ensure all participants were aware of the requirement.

22 Joint AL (PG&E AL 5138-E-A, SCE AL 3653-E-A, SDG&E AL 3108-E-A), included an update to the verification plan, which relies an audit using a statistically-valid methodology.

23 AL 5335-E filed July 23, 2018, clarified that while PG&E did not need to shift funds at that time, it reserved the right to do so at a later day if necessary to cover PR-related expenses.

DR participants who are subject to the prohibition[24] have to attest to the status of their PRs, which is organized into three possible attestation options. The following table summarizes these three options.

TABLE 2-2
SUMMARY OF ATTESTATION OPTIONS FOR PROHIBITED RESOURCES

Line No.	Attestation Option	Description of Option	Implications
1	Option 1	I do not have a PR.	None if accurate
2	Option 2	I do have a PR, but I will not use it during a DR event.	None if accurate
3	Option 3	I do have a PR, and I may need to use it during a DR event.	Participant has to take a Default Adjustment Value (DAV).[a]

(a) The DAV is a reduction in the DR incentive payment based on the nameplate capacity of the PR.

Existing DR participants for both BIP and CBP were required to complete attestations as part of the process for PR prohibition.[25] The prohibition also applies to the Demand Response Auction Mechanism (DRAM) and to certain pilots.[26] New participants in impacted programs are required to attest as part of the DR enrollment process (i.e., completing the Add/Delete form) to one of the three options identified in the above table (Table 2-1).

Res.E-4906 also included several actions, besides the annual verifications, to inform the CPUC about ways to track and measure the usage of PRs along with the establishment of a pilot. First, OP 37 of Res.E-4906 required each utility to file an application on meters and loggers

24 D.16-09-056, pp. 94-95, OP 3 exempted the following programs from the prohibition: air conditioner cycling programs, permanent load shifting programs, schedule load reduction programs, the optional binding mandatory curtailment, TOU rates, critical peak pricing, RTP, and peak-time rebate. This exemption was re-affirmed by D.18-06-012.

25 D.16-09-056, OP 3: The DRAM, along with PG&E's Excess Supply (XSP) and Supply Side (SSP) Pilots were not exempt from the prohibition. Also, residential participants in an Aggregator program (e.g., CBP) while technically subject to the prohibition were not required to provide attestations. Instead, participants were required to be informed of the prohibition as part of their contract (terms of service) per Res.E-4838 (Apr. 18, 2017) p. 57, OP 18.

26 Examples of such pilots include the former XSP and SSP Pilots.

by October 19, 2018.[27] While there were a large number of data requests associated with the filing, hearings were initially deferred and subsequently cancelled.[28] The proceeding has remained dormant since 2019, as the statutory deadline has been extended three times.[29]

To further help supplement the record, Res.E-4906 called for a "test year" pilot deployment of meters and loggers,[30] which occurred in the first year of the prohibition in 2019. The pilot resulted in the filing of a report[31] developed by Nexant, the pilot administrator and VA, which made a number of recommendations.[32] Subsequent to the issuance of the pilot report, a workshop was held to review the findings.[33]

As indicated earlier, an annual audit by the VA was undertaken for DR program years 2019, 2020 and 2021, by Nexant.[34] All audits resulted in the issuance of annual reports.[35] While Res.E-4906 envisioned ongoing audits for the "first three to five years,"[36] PG&E is of the opinion that this term was temporary until the final outcome of the Prohibited Resources Application proceeding made a determination of the permanence of a monitoring and

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27 A.18-10-008, et al.

28 Administrative Law Judge (ALJ) Hymes Ruling dated July 24, 2019 for deferral and e-mail by ALJ Hymes dated January 3, 2020 informing parties that a ruling to defer hearings would be issued.

29 D.20-04-031 extended the deadline up to October 19, 2020; D.21-04-020 further extended the deadline up to October 19, 2021. More recently, D.21-10-014 issued in October 2021, extends the statutory deadline to October 19, 2022.

30 Res.E-4906 (June 21, 2018) p. 102, OP 37(i).

31 SCE made the filing on behalf of the three utilities on November 18, 2019.

32 Nexant report titled "California Demand Response Prohibited Resources Verification Administrator Metering Pilot Report" dated November 18, 2019 at p. A-7. Link: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/j/6442463581-joint-ious-supplemental-filing-of-prohibited-resources-2019-test-year-pilot.pdf (current as of 4/24/2022).

33 CPUC workshop dated December 5, 2019. Information available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops (current as of 4/24/2022).

34 The audit for 2021 has been initiated by Nexant as of September 2021.

35 2019 Nexant Program Year Audit Report dated January 31, 2020; 2020 Nexant Program Year Audit Report dated January 31, 2021. Both reports were served by SCE on behalf of the three IOUs.

36 Res.E-4906,(June 21, 2018) p. 30.

enforcement regime. PG&E requests additional clarity from the Commission related to the nature of future annual audits by the VA, including additional funding of $1.1 million for the 2024-2027 period.[37] Additionally, the monitoring and enforcement regime resulting from the final decision in A.18-10-008 would need to be modified for years 2024-2027 if PG&E's request to suspend the prohibition for BIP is granted (discussed in subsection 3 below).

2. Addressing Renewable Fuels in the Prohibited Resources Framework

An element of the PRs framework that warrants consideration pertains to the utilization of renewable fuels. By way of background, Res.E-4906 originally provided for the provisioning of "renewable" fuels, which had received certification from the California Air Resources Board (CARB), to be utilized by a backup generator and cause it to be exempt from the PR restriction.[38] However, no standards for fuel switching have been developed partly due to the CPUC's desire to learn more about fuel switching per the annual audits undertaken by the VA.[39]

Other than the lack of explicit standards for fuel switching, there is another concern which was raised by parties in 2021,[40] that the exemption

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[37] Funding request is included under Category 7, DR Measurement and Evaluation Committee.

[38] Res.E-4906 (June 21, 2018) p. 78:

> "We agree and clarify that if a fuel (e.g., renewable gas, renewable diesel, biodiesel) has received renewable certification from the CARB, it is exempt from the prohibited resource policy in D.16-09-056. Hence if a customer switches to a fuel that has received renewable certification, it may update its attestation by providing documentation that confirms the operational change."

[39] Res.E-490 (June 21, 2018) p. 104, OPs 46 and 47states:

- OP 46: "Utilities shall require the verification administrator to include in its annual report instances of operational changes involving fuel switching from renewable to non-renewable fuels and violations involving reverse fuel switching."
- OP 47: "Utilities shall include tariff changes that allow customers to update their attestations for fuel switching, specifically from fossil-based fuels to renewable fuels, provided such fuels has received renewable certification from the California Air Resources Board. A switch must be substantiated by documentation that confirms this operational change."

[40] R.20-11-003 (Emergency Reliability OIR): January 11, 2021 Opening Testimony file by the DR Coalition at p. 23; January 19, 2021 Rebuttal Testimony filed by the Joint DR Parties at p. 9.

per Res.E-4906 is too narrow, as it limits fuel switching to CARB-certified fuels, which are generally liquid transportation fuels. Specifically, the ability to utilize nonliquid fuels such as renewable gas or green hydrogen that are potentially Renewable Portfolio Standard-eligible could provide greater flexibility. Therefore, PG&E recommends the CPUC coordinate with other state agencies to assess fuel switching and consider expanding the fuel types that could be used to exempt backup generators from being classified as PRs.

3. Prohibited Resource Allowance for the Base Interruptible Program

PG&E proposes the temporary suspension of the PR restrictions for customers participating in the BIP in 2024 and 2025. When PR restrictions for BIP were first implemented in late 2018/early 2019, PG&E experienced a loss of customers and MW enrolled in the program. As illustrated in Exhibit (PG&E-2) Chapter 3, Table 3-2, BIP has continued to experience significant attrition and is stagnating in growth. At the same time the grid's reliance on reliability resources has only grown and is expected to do so for the near term. PG&E believes that a removal of PR restrictions could increase the availability of emergency resources needed to help stabilize the grid and minimize the likelihood of rotating outages during extreme weather events. Since BIP is only leveraged during short-term, emergency situations, PG&E does not expect this change to meaningfully impact California's decarbonization goals. The PR restrictions would remain in place for test and retest BIP events which are authorized in the E-BIP tariff but do not constitute an emergency event. PG&E proposes that PR restrictions on BIP be lifted for two years, and then would be subject to review. If the PR suspension is granted for BIP, PG&E can implement a process for administering the suspension, including any updates that may be needed for attestations.

Regardless of the outcome of the request for suspension, PG&E recommends the CPUC to take action to provide for greater clarity in fuel switching, including expanded allowances for renewable fuels as discussed in Section 2 above.

a. Temporary Suspension of Prohibited Resource Restrictions Have Been Needed to Stabilize the Grid in Recent Years

For the past two years, the state has seen a pattern of making exceptions for PR use under extenuating circumstances; PR restrictions were suspended or modified temporarily for both summers 2020 and 2021. In 2021, the Governor Newsom issued a proclamation that allowed a temporary exemption from PR restrictions from July 30 through October 31, 2021:

> On any day for which the CAISO issues a Grid Warning or Emergency… Restrictions on the use of prohibited resources adopted by the California Public Utilities Commission under Decision 16-09-056, Ordering Paragraphs 3 and 4[b], and as implemented in the tariffs of regulated energy utilities, are suspended for any non-residential customer who is enrolled in the Base Interruptible Program or Agricultural & Pumping Interruptible Program.[41]

A letter from the Executive Director of the CPUC also clarified PR rules from August 17-19, 2020:

> Any action taken by a participant in the BIP program to operate a prohibited resource during the heat storm that is forecast to continue through the end of August 19, 2021 while also responding to a directive to reduce load under the BIP program is consistent with the intent of D.16-09-056, subsequent tariff rules, and relevant attestations to allow for the use of prohibited resources for safety reasons or as incremental load curtailment. Such action should not make the customer ineligible for participation in the BIP program, provided that the customer is able to document that the use of the prohibited resources creates an incremental reduction to the customer's dependence on the grid beyond the BIP obligations.[42]

BIP is an emergency DR program that is only called upon during extreme grid conditions like those experienced in 2020 and 2021. Temporary PR exemptions issued during summer have no impact on BIP enrollment growth due to the enrollment and participation timeline for the program, and during the 2020 and 2021 emergencies, PG&E had

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[41] Governor's "Proclamation of a State of Emergency," issued July 30, 2021, <https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf>, (as of Apr. 21, 2022).

[42] Letter from the Executive Director of the CPUC titled "Emergency Action to Combat Heatwave," issued August 17, 2020.

no visibility into the impacts of these exemptions on load reduction among existing customers. PR exemptions for an emergency program would be much more impactful if they were lifted prior to an emergency because it would encourage customer enrollments and program growth ahead of summer conditions.

b. Large Potential of Untapped Reliability Resources

In the course of conducting an extensive customer outreach campaign in 2021, PG&E became aware of a large pool of prospective BIP customers who are only able to participate in the program by using backup generation that is currently categorized as a PR. These customers represent many MWs of unharnessed load reduction capacity. In addition, if the PR prohibition is removed temporarily for BIP, PG&E could conduct outreach to customers that left the program in 2019 due to the introduction of PR restrictions.

A temporary suspension of the PR prohibition for BIP, if approved, would help address significant emergency short-term capacity shortages.

F. Emergency Demand Response Cap

A 2010 decision, which incorporated a settlement agreement, had capped emergency DR programs that count for RA.[43] For PG&E, this cap applies to BIP, which is integrated into the CAISO's market as a Reliability Demand Response Resource. Since 2014, the cap has been at 2 percent of CAISO system peak.[44] Each IOU's share of the cap was based on its overall load

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43 D.10-06-034. The settlement agreement specified the removal of a cap per CPUC D.09-08-027, which was placed on MWs that each IOU could enroll in these types of programs in 2009 through 2011. The settlement applied to all IOU-triggered DR programs (referred to as "emergency-based" or "reliability-based" DR programs), in which customer load reductions are triggered only in response to abnormal and adverse operating conditions, such as imminent operating reserve deficiencies or violations of transmission constraints.

44 The 2012 cap was 3 percent; the 2013 cap was 2.5 percent and it went to 2 percent as of 2014 until temporarily raised by D.21-03-056.

share as applied to the CAISO's all-time peak load.[45] The actual computation for PG&E's specific load share amount is filed as part of the annual LI Filing.[46]

A 2018 decision made modifications to the way the "allocated capacity" and the "headroom" is calculated.[47] This change stemmed from a workshop held on February 18, 2018, which resulted in the submission of a joint report by the IOUs on March 30, 2018. One of the outcomes of the report was a utility agreement for consistency on the calculation and management of the reliability cap across the three utilities.

More recently, in response to the grid challenges the state faced in August and September 2020, the CPUC issued D.21-03-056, which mandates a number of modifications to bolster existing DR programs. One of these changes is the raising of the reliability cap on a temporary basis to 3 percent for the duration of the ELRP pilot, which is scheduled to sunset at the end of October 2025.[48] In Exhibit (PG&E-2) Chapter 4, PG&E proposes the continuation of ELRP pilot from 2026-2027 in a more simplified offering to participants. Should ELRP pilot be extended, PG&E requests that the 3 percent cap also be extended until the new sunset date.

G. Program Enhancement Flexibility

As required by D.16-09-056, PG&E filed its 2018-2022 mid-cycle review (MCR) on April 1, 2020 via AL 5799-E. The intent of PG&E's MCR was to inform the Commission of its progress and to propose modest program changes midway through the 5-year DR cycle. As of the filing of this testimony, AL 5799-E has not yet been approved by the Commission.

PG&E finds that the 2018-2022 MCR did not prove to be an effective use time for either the IOU's or the Energy Division's staff. Given that the IOUs are already required to provide the Commission with monthly reports on DR program activity and spending, the MCR requirement adds very little value. Additionally,

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[45] The CAISO historic peak load of 50,270 MW set on July 24, 2006 continues to be applied.

[46] The analysis is included in Appendix RR of PG&E's annual LIP filing due on around April 1 of each year.

[47] D.18-11-029, p. 85, OP 5.

[48] D.21-03-056, Attachment 1, at p. 16.

Commission rules permit IOUs to propose program changes via advice letters. For these reasons, PG&E proposes that no MCR be required in 2023-2027.

California has experienced a tremendous change in market and grid conditions, as well as trends in technology adoption and customer preferences over the 2018-2022 period. These changes are anticipated to continue over the 2024-2027 period. PG&E believes it is imperative that its DR portfolio be able to quickly adapt to these dynamics.

To that end, PG&E seeks authority to re-evaluate and adjust the design elements (e.g., incentive and penalty structure, event durations, etc.) of its programs and pilots via submission of a voluntary Tier 1 or 2 AL by December 1st of each year in the funding period. PG&E proposes that the program adjustments would become effective by May 1st of the following year.

H. Report Summaries

This section provides an update on the results of: (1) the RBWG effort, which culminated in a final report, and (2) a summary of the Disadvantaged Communities Demand Response Pilot (DAC DR Pilot), and (3) clarifies the status of the Customer Information Working Group (CIWG) Report from the DRAM forum.

1. Retail Baseline Working Group (Report)

OP 19 of D.19-07-009 tasked the RBWG with developing proposals to address five baseline issues. The RBWG was required to present its proposals in a report served to all parties no later than April 1, 2021. In response, the findings of the RBWG were served on March 1, 2021, in the form of a report. Relatedly, D.19-07-009 also requested the utilities to include the RBWG report in the "testimony for their 2023-2027" DR Application.[49] Accordingly, the RBWG report is included in this filing as Chapter 2 Attachment A.

The RBWG group was tasked with addressing the following five questions,[50] which are discussed in detail within the final report.

1) *Assess if adjustment cap of + or – 40 percent is still suitable for retail 10-in-10 when the day of adjustment for wholesale is + or – 20 percent.*

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[49] D.19-07-009, p. 85.

[50] D.19-08-009, p. 86 and, pp.113-114, OP 19.

2) Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.

3) Consider flexibility in changing retail baselines.

4) Consider whether the wholesale and retail baseline should be aligned, or can they be different.

5) Consider the pros and cons of an aggregate versus individual baseline.

The scope of the RBWG was limited to CBP based on the fact that it only applies to the use of energy baselines.[51] Moreover, it excluded the DRAM because OP 17 in D.19-07-009 explicitly approved several baseline options for use by DRAM.

2. Disadvantaged Communities Demand Response Pilot

- 2018-2022 Pilot Description

The DAC DR Pilot was established by the Commission in the original funding decision for the 2018-2022 period.[52] PG&E partnered with Olivine, Inc., a well-regarded industry leader providing infrastructure and services that enable distributed and aggregated resources to effectively and efficiently offer grid services in the DAC areas. Olivine has extensive expertise in working with both IOUs and CCAs to administer DR programs.

The pilot leveraged and expanded on elements of a prior DAC pilot called the Community Energy Initiative held in the City of Richmond.[53] For the DAC DR Pilot, PG&E and Olivine studied the willingness and ability of residential customers to provide DR in DACs near the Malaga Power Generation facility in south-central Fresno.[54] Households within the pilot area have some of the highest environmental justice percentile

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51 BIP applies a Firm Service Level methodology to assess performance. SmartAC does not compensate based on performance as it relies on an upfront enrollment incentive, as well as more recently on a retention incentive as approved in D.21-12-015.

52 D.17-12-003, p. 200, OP 58.

53 Findings from the Olivine Community Energy Initiative, (May 2, 2019), <https://olivineinc.com/2019/05/> (as of Apr. 21, 2022).

54 The specific zip codes in Fresno were 93701, 93702, 93703, 93706, 93721, 93725, and 93728. Note that 94706 was added via a supplemental AL 5477-E-A filed on May 7, 2019, due to the updated boundary of South Central Fresno pursuant to Assembly Bill 617.

rankings in the State, according to the State's analysis conducted using the CalEnviroScreen Tool.[55] Table 2-3 outlines the pilot's attribute.

TABLE 2-3
KEY DAC DR PILOT ATTRIBUTES

Line No.	Attributes	DAC DR Pilot
1	Study Population	~500
2	Climate Zone	Inland (summer peaking)
3	Air Conditioning Saturation	High
4	Customer Outreach	Social Media, Community-Based Organizations (CBO), Energy Savings Assistance Program contractors, and Community Assistance Navigators
5	DR Type	Load Reduction and Load Shifting
6	Reward Type	Reward Redeemed via Online Store for Gift Cards or Energy Automation Devices

- Regulatory Background

  The DAC DR Pilot culminated in PG&E filing a pilot plan with the CPUC via an implementation AL in 2019.[56] This plan was based on a number of prior activities that were originally initiated through a Scoping Memo in 2017.[57] Subsequently, the CPUC allocated budget to the DAC DR Pilot in the decision authorizing funding for the utilities' 2018-2022 DR Funding Decision.[58] PG&E's allocated budget was $1 million over the funding cycle with 10 percent earmarked for evaluation. Following workshops and comments, the Commission issued D.18-11-029, which outlined the final requirements for the DAC pilot.

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55 Based on theCalEnviroScreen tool (3.0), CARB, CalEviorScreen 3.0, CalEnviroScreen 3.0 | California Air Resources Board < https://ww2.arb.ca.gov/resources/documents/calenviroscreen-30 >.

56 AL 5477-E filed February 8, 2019; AL 5477-E-A filed on May 7, 2019.

57 Scoping Memo and Joint Ruling of Assigned Commissioner and ALJs, March 15, 2017 at 4, issue number 8, as indicated in D.17-12-003 at p. 140, fn. 242.

58 D.17-12-003, p. 200, OP 58.

- Pilot Update During 2018-2022 Funding Cycle

The DAC DR Pilot had three major components, which included a pre-enrollment survey, DR events, and a post-season survey. The surveys were critical in obtaining psychographic data and performance data to better understand the profile of DAC participants versus non-DAC participants. With respect to DR events, the DAC DR Pilot contained both traditional load drop events and load shifting. Interface with the pilot included the use of either a webpage or a smartphone application.[59] Participants were compensated incrementally as they completed surveys, DR events, and other milestones, including incentives for participant referrals.

The onset of COVID-19 (coronavirus) posed a significant challenge in the pilot implementation.[60] This was because the recruitment process PG&E intended to use was heavily reliant on CBOs[61] as a major pathway for recruiting in hard-to-reach communities. Since CBOs heavily rely on face-to-face engagement, shelter in place and social distancing significantly limited outreach. As a result, the original recruitment period that was scheduled to close in Q2 of 2020 was extended through year end 2020. Also, PG&E redirected resources to

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59 Webpage, smartphone applications, along with marketing collateral, were offered in both English and Spanish.

60 PG&E filed AL 5859-E on June 24, 2020 in response to the challenges created by coronavirus. This advice filing proposed among other things to extend the pilot schedule and to reformulate the proposed schedule to provide greater flexibility to pivot. This AL was protested by the Public Advocates Office at the Commission (Cal Advocates) on July 14, 2020. On July 21, 2020, PG&E responded to the protest. Thereafter, the Energy Division suspended the AL effective July 25, 2020. PG&E engaged with the Energy Division during the summer of 2020 in the hopes of addressing concerns related to the advice filings. Ultimately, PG&E withdrew the AL on October 8, 2020.

61 CBOs can be social service agencies, non-profits and formal/informal community groups.

developing a greater online presence (i.e., social media) in the absence of in-person engagement.[62]

The key learnings of the pilot, include the following: (1) Participants were generally aware of DR programs, contrary to pre-conceived assumptions that DAC participants may not be; (2) Participants performed at levels at or higher than non-DAC participants for load shedding events;[63] and (3) Participants performed comparably to those of a direct load control program, such as an air conditioning curtailment offering (e.g., PG&E's SmartAC).

3. Customer Information Working Group

Res.E-5110 issued on December 18, 2020, authorized the Energy Division to initiate a CIWG no later than 60 days after the adoption of the resolution. The CIWG was tasked with studying The California Efficiency + Demand Management Council's proposal and to produce a report by June 1, 2021.[64] The resolution also ordered the IOUs to include the CIWG report in their 2023-2027 DR Portfolio applications.[65] However, the Energy Division did not initiate the working group, and the report was never produced. Since there was no report generated by the CIWG, this application does not include one.

I. Conclusion

There are numerous policy and regulatory issues that help to inform DR programs and pilots. Some of these existed prior to the 2018-2022 funding cycle; however, a number of them surfaced or were further developed during the 2018-2022 cycle (e.g., DACs, PRs). The ever-changing role of DR, driven by

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62 Due to the challenges posed by coronavirus, especially as it pertained to recruitment, PG&E filed AL 5859-E on June 24, 2020, in the hopes of modifying the approved budget composition to provide greater flexibility. This AL was protested by Cal Advocates. Attempts at timely engagement with the Energy Division and Cal Advocates ultimately led PG&E to withdraw its filing in October 2020.

63 Non-DAC residents performed better at load shifting events; however, the general hypothesis is that participating in a program/pilot that has both load drop and load shifting may create some level of confusion. Therefore, it is unclear at this time if the pilot had only included a load shift event (no load drop) that participants would have performed better.

64 Res.E-5110 (Dec. 18, 2020) p. 49, OP 5.

65 Res.E-5110 (Dec. 18, 2020) p. 50, OP 6.

both regulatory and technological changes, dictates a need to ensure that policies are supportive of DR and are periodically re-assessed through the regulatory process. PG&E's proposals, which are shown in Table 2-1, outline the specific requests for this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

RETAIL BASELINE WORKING GROUP FINAL REPORT

RETAIL BASELINE WORKING GROUP

FINAL REPORT

March 1, 2021

RETAIL BASELINE WORKING GROUP
FINAL REPORT

Contents

EXECUTIVE SUMMARY

Decision (D.) 17-12-003 adopted demand response (DR) activities and budgets for years 2018 through 2022, but kept open the demand response applications filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the IOUs) (Applications (A.) 17-01-012, 17-01-018, and 17-01-019) in order to consider remaining matters in the consolidated proceeding, including the issue of demand response baselines.[1]

D.17-12-003 clarified that alternative wholesale baselines had been developed through the California Independent System Operator's (CAISO) Energy Storage and Distributed Energy Resources (ESDER) Phase II process.[2] Further, D.17-12-003 concluded that alternative baselines should be addressed in a future decision in that proceeding (outside of the mid-cycle review)[3] and instructed the Utilities to file a copy of the wholesale baselines tariff, following adoption of the tariff by the Federal Energy Regulatory Commission (FERC).[4] On November 8, 2018, in compliance with D.17-12-003, the Utilities filed a copy of the *FERC Tariff Amendment to Implement Energy Storage and Distributed Energy Resource Requirements, i.e., baseline methods*.[5]

The Administrative Law Judge presided over a prehearing conference on January 10, 2019 to establish next steps for addressing baselines. At a workshop held on March 22, 2019, the Utilities presented information on the current Commission-approved retail baselines; the CAISO wholesale Baselines; similarities, differences, and interaction between retail and wholesale baselines; and the costs of and funding options for expanding baseline options. A ruling was issued on April 8, 2019, directing parties to respond to a set of questions regarding baselines.[6] Parties filed responses to the April 8, 2019 ruling questions on April 24, 2019; replies were filed on May 3, 2019.[7]

On July 11, 2019, the Commission issued D.19-07-009 to address the Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage. Ordering Paragraph 19 established the Retail Baseline Working Group (RBWG) to develop proposals to address five baseline issues.[8] The RBWG is required to present its proposals in a report served to all parties no later than April 1, 2021.[9]

[1] D.19-07-009 at page 3.
[2] D.17-12-003 at Finding of Fact 149.
[3] *Id*. at Conclusion of Law 74.
[4] *Id*. at page 153.
[5] D.19-07-009, page 4.
[6] See Administrative Law Judge's Ruling Directing Responses to Questions and Filing of Previous Demand Response Baseline Development and Implementation Costs, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M279/K201/279201986.PDF
[7] The following parties filed opening comments: Council, OhmConnect, PG&E, SDG&E, and SCE. The following parties filed reply comments: Council, OhmConnect, PG&E, and SCE.
[8] D.19-07-009, Ordering Paragraph (OP) 19.
[9] *Id*. at 86.

PURPOSE

The purpose of this final report is to describe the activities and proposals of the RBWG pursuant to D. 19-07-009, Ordering Paragraph 19.

As ordered by Ordering Paragraph 19, the RBWG discussed and developed proposals to the following issues:

1. Assess if adjustment cap of + or – 40 percent is still suitable for retail 10-in-10 when the day of adjustment for wholesale is + or – 20 percent.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned, or can they be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

The Capacity Bidding Program (CBP) is the only IOU retail DR program that uses an energy baseline (BL) for settlement.[10] Therefore, the RBWG addressed CBP baseline issues. The Demand Response Auction Mechanism (DRAM) baselines were out of scope for the RBWG.[11]

CHRONOLOGY OF WORK DONE

Participants

RBWG participants have included[12] the Energy Division (ED) Staff of the California Public Utilities Commission (CPUC), SCE, PG&E, SDG&E, Public Advocates Office (PAO), California Energy Storage Alliance (CESA), California Efficiency + Demand Management Council (CEDMC), EnergyHub, OhmConnect, California Energy Commission (CEC), Sunrun, ecobee, NRG, Center for Sustainable Energy, CPower, Enel X, Clean Energy Regulatory Research, and Polaris Energy.

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[10] The Base Interruptible Program (BIP) uses a Firm Service Level (FSL).

[11] See D.19-07-009, OP 17 ("We adopt, for retail settlement purposes in the Demand Response Auction Mechanism, the four baseline methods approved by the Federal Energy Regulatory Commission: (1) a day matching customer load 10-in-10 baseline with a 20 percent cap; (2) a weather matching baseline with a 40 percent cap; (3) the use of control groups; and (4) a five-in-ten baseline for residential customers, with a 40 percent cap.").

[12] Not all identified parties participated consistently. While the RBWG was originally coordinated by an ED staff member, the IOUs were requested to continue to lead after her departure from the CPUC.

Stakeholder Meetings

Between September 2019 and November 2020, the RBWG held a series of meetings, some held in-person at the CPUC in San Francisco, and some held remotely. In-person meetings were held on September 24, October 22, and November 13, 2019 and conference calls were held on October 7 and 28, 2020 and November 19, 2020.

External Consultant

In order to help inform the five questions tasked by the CPUC to be addressed by the RBWG, external consultant Applied Energy Group (AEG) was engaged to perform an analytical study of the efficacy of the different day-of adjustments caps. The scope of this study was limited to IOU non-residential customers in CBP by analyzing 10 in 10 baselines either at the aggregate or individual customer level with day of adjustments of 20%, 30% and 40%. Subsequent to the completion of the study, AEG prepared a report,[13] which was distributed to the service list on October 8, 2020 (see Appendix B hereto) and thereafter AEG staff presented its findings to interested participants on October 28, 2020 (see Appendix C hereto).

REQUIRED ISSUES

<u>Issue #1</u>: Assess if adjustment cap of + or – 40 percent is still suitable for retail 10-in-10 when the day of adjustment for wholesale is + or – 20 percent.

> **Issue Definition:** The issue presented is whether third-party Aggregators should continue to utilize the current CPUC adopted + or – 40 percent adjustment cap for *retail* (CPUC) use or reduce the adjustment cap to + or – 20 percent.[14] Such an adjustment cap would continue to be optional and left to the discretion of the third-party Aggregator during the monthly CBP nomination process. On the *retail* side, the Day-Of Adjustment is generally calculated using the first three of the four hours prior to the event, divided by the average load for the same hours using the prior 10 weekdays for CBP participants. This Day-Of Adjustment should not exceed plus or minus 40% of the individual calculated baseline.
>
> **How it affects DR:** The use of the adjustment cap facilitates measurement of demand response performance based on actual demand and the weather condition on the event date. The adjustment cap will limit the magnitude of the baseline adjustment and is necessary to reflect a more accurate load condition during the event.

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[13] See "Baseline Comparative Analysis – 2019 Statewide Load Impact Evaluation of the California Capacity Bidding Programs," dated October 1, 2020.

[14] D. 12-04-045, OP 10, set the "optional" adjustment cap at +/- 40 percent for the 10 in 10 baseline. Previously, D. 09-08-027 (pp. 140-141) established a +/- 20% adjustment cap for the 10 in 10 baseline. (Note: the term "retail" pertains to the baseline methodology utilized for settlement under CPUC rules as compared to wholesale settlement under the CAISO tariff.)

Proposed Solution(s): The RBWG recommends retaining the current + or – 40 percent adjustment cap. The reasons for this are: (1) AEG's study did not find a large difference between the + or - 20 percent and + or - 40 percent caps, (2) parties generally were amenable to the + or – 40 percent cap as it provides greater flexibility, and (3) retaining the current cap eliminates the need for system changes and costs that utilities would face if the cap were lowered to + or – 20 percent.[15]

Issue #2: Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.

Issue Definition: This issue pertains to which entity should determine whether to elect to utilize the adjustment cap (i.e., +/- 20% or +/-40%). As part of the RBWG, this topic was restated to be one that is between either the utility on the one hand or the customer/Aggregator on the other. Because in the CBP the Aggregator owns the relationship with the customer, it would be appropriate for the Aggregator to work with the customer to determine whether to utilize the adjustment cap. As a matter of clarification, the issue at hand is limited to the adjustment cap and does not pertain to the selection of a different baseline option (e.g., going from a 10 in 10 baseline to 5 in 10 baseline), which would require CPUC approval.

How it affects DR: The entity that has the ability to elect to utilize the baseline adjustment cap is in the best position to understand what is most suitable.

Proposed Solution(s): The general consensus is that the current framework where the Aggregator (not the utility) determines whether or not to apply the adjustment cap is adequate. As it relates to the determination between the Aggregator and its customer, this would be between these two parties and would not involve the utilities.

Issue #3: Consider flexibility in changing retail baselines.

Issue Definition: This issue pertains to how frequently a party can modify its adjustment cap (i.e., +/- 20% or +/-40%). Since the current nomination frequency is monthly, parties generally agree that the adjustment cap option can be

[15] The AEG study began well before the summer 2020 heat waves, and the initial draft of the AEG Report was released in July 2020. AEG examined event-days and event-like days from 2018 and 2019, and as such its analysis did not reflect the extreme heat conditions that occurred in 2020. Although this did not necessarily impact AEG's analysis because only a + or – 20 percent or + or – 40 percent day-of adjustment was being considered. However, performing the same analysis under the 1-in-30 weather conditions that prevailed during the August and September 2020 heat events would have been informative.

selected as frequently as monthly. It is not interpreted to be the frequency by which a *retail* baseline methodology can be changed (e.g., going from a 10 in 10 baseline to 5 in 10 baseline) because the 10 in 10 baseline is the only available *retail* baseline option for CBP at this time.[16] If additional baseline options become available, then rules for utilization would need to be developed.

How it affects DR: The frequency by which the baseline adjustment cap is applied can potentially affect performance based on customer operations.

Proposed Solution(s): Keep the monthly adjustment option methodology for that specific month, such that a customer cannot modify the adjustment cap until the next month.

Issue #4: Consider whether the wholesale and retail baseline should be aligned, or can they be different.

Issue Definition: This issue can be interpreted in three ways. The first interpretation is that all elements of a baseline option need to be aligned. This includes the actual baseline option (e.g., 10 in 10), the adjustment cap (e.g., +/- 40%) and the settlement level (individual/customer vs. aggregate/resource). The second interpretation is that while the baseline option (e.g., 10 in 10 baseline) needs to match there can be divergence in the adjustment cap. The third interpretation is that the baseline option and adjustment cap are aligned, but there can be divergence in the settlement level (individual/customer vs. aggregate/resource). The following table illustrates this point through four combinations.

Combination	Baseline Option	Adjustment Cap	Settlement Level
1	10 in 10	+/- 20%	Individual/Customer
2	10 in 10	+/- 40%	Individual/Customer
3	10 in 10	+/- 20%	Aggregate/resource
4	10 in 10	+/- 40%	Aggregate/resource

[16] D.19-07-009, OP 18, ordered the three Utilities to include proposals for implementing the 5 in 10 baseline for residential customers as part of their respective Mid-Cycle Advice Letters, which were due April 1, 2020. At the time of submission of this RBWG Final Report, the CPUC had not acted on these Mid-Cycle Advice Letters.

The RBWG interpreted the question as being limited to the adjustment cap and the settlement levels because the 10 in 10 baseline option is the only one available at the *retail* level at this time.

With respect to the adjustment cap, the *wholesale* (CAISO) baseline rules provide for a +/- 20% adjustment cap under the 10 in 10 baseline option.[17]

As it relates to the settlement level, which is further discussed in Q-5, the CPUC at the *retail* level prescribes the use of an individual (customer) level baseline while the CAISO at the *wholesale* level mandates an aggregate/resource level baseline.

How it affects DR: While lack of alignment may create certain differences for *retail* (CPUC) and *wholesale* (CAISO) settlements, the magnitude of the differences may or may not have material cost implications.

Proposed Solution(s): The general consensus is that *wholesale* and *retail* baselines do not need to be aligned, since AEG did not find any particular baseline combination to clearly outperform others.

<u>Issue #5</u>: Consider the pros and cons of an aggregate versus individual baseline.

Issue Definition: The issue deals with the level at which settlement occurs. An individual baseline means that settlement occurs at the participant (customer) level. An aggregate baseline is at the resource level comprised of multiple participants (customers). Today, the *retail* (CPUC) settlement is at the individual level while the *wholesale* (CAISO) settlement is at the resource level. Please refer to the AEG report, which discusses the pros and cons of aggregate vs. individual baselines (see pp. 6-7 of the study in Appendix B).

How it affects DR: An aggregate baseline may not necessarily be reflective of the performance of individual participants. Therefore, the two baseline calculations may lead to different load reduction estimates for the same participant/resource.

Proposed Solution(s): The RBWG generally agrees that having different settlement levels is acceptable (i.e., individual participant for *retail* (CPUC) and resource for *wholesale* (CAISO)). While the AEG study recommends an aggregate baseline for *retail* (CPUC) settlement (p. 5 of study), which would

[17] CAISO Tariff Section 4 Roles and Responsibilities, Subsection 4.13.4.1c Ten-in-Ten Baseline Methodology. Available at http://www.caiso.com/Documents/Section4-Roles-and-Responsibilities-asof-Jan1-2021.pdf.

seemingly align with the *wholesale* (CAISO) methodology, there are three reasons against doing so. First, the findings of the AEG study were not conclusive in identifying the single best baseline, as the accuracy of a baseline depends on the customer mix. And there was no consensus within the RBWG on the preference for one or the other. Second, moving to an aggregate baseline at the *retail* (CPUC) level would involve system modifications and associated costs for the utilities. Third, currently Aggregators have the greatest visibility into their customers' performance using individual baselines, which would not be as visible under an aggregate/resource baseline.

APPENDIX

Appendix A: Applied Energy Group's Baseline Analysis Final Report

Appendix B: Applied Energy Group's Baseline Analysis Final Presentation

Appendix A:
Applied Energy Group's Baseline Analysis Final Report

AEG
Applied Energy Group

BASELINES COMPARATIVE ANALYSIS

2019 Statewide Load Impact Evaluation of the
California Capacity Bidding Programs

October 1, 2020

BASELINES COMPARATIVE ANALYSIS

Report prepared for:
PACIFIC GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON
SAN DIEGO GAS & ELECTRIC COMPANY

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SUMMARY AND KEY FINDINGS

This report documents the comparative analysis performed by Applied Energy Group (AEG) contracted by the PG&E on behalf of the Investor Owned Utilities (IOUs) to fulfill the Demand Response Retail Baseline Working Group (Working Group) requirements.

Research Objectives

Per CPUC Decision 19-07-009[1], the April 8, 2019 Ruling asked parties whether the current retail settlement baseline for the Capacity Bidding Program (CBP) should be revised, what the revisions would entail, and what implementation timeline should be adopted. Discussions during the March 22, 2019 workshop explained that the relationship between the retail and wholesale settlement baselines results in differences in load reduction quantities. Multiple parties agree that the retail settlement baselines should align better with the wholesale settlements. The purpose of this report is to compare how the current retail baselines perform along with identifying better performing baseline options, those that provide the highest accuracy while minimizing bias. In a perfect world, the retail baseline would result in the same load impact calculations as the wholesale baselines. The current retail settlement baseline is an individual 10-in-10 baseline with a maximum 40% adjustment cap. The wholesale settlement baseline is an aggregate[2] 10-in-10 baseline with a maximum 20% adjustment cap.

The D. 19-07-009 established the Working Group to investigate the following issues[3]:

1. Assess if an adjustment cap of ±40% is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is ±20%.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned or if they can be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

The goal of this analysis will directly address the 1st and 5th issues and hopefully provide insights into the other 3 issues. This analysis investigated six potential options for retail settlement baselines, including both the aggregate and individual baselines, with three different adjustment caps, 20%, 30%, and 40%. The main goal of this analysis was to identify the most effective baseline to represent the counterfactual, or what would have happened in absence of an event, with respect to accuracy and bias.

Research Methodology

To perform the comparative analysis, AEG calculated hypothetical baselines and compared them to a known counterfactual for each of the six potential baselines for both event days and event-like days in program years 2018 and 2019. Then, AEG summed the baseline estimates to the resource level

[1] CPUC D.19-07-009, p. 83.

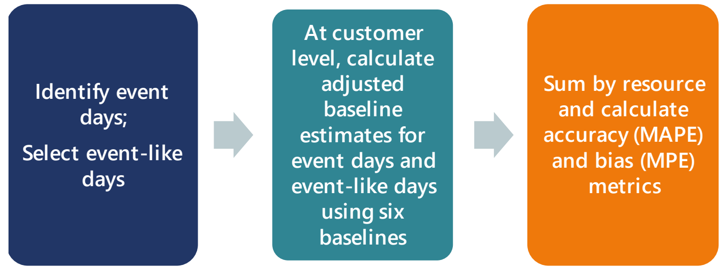
[2] Aggregate baselines are performed at the resource level, which is comparable to Product+Aggregator+Sub-LAP level.

[3] CPUC D.19-07-009, p. 86.

(segmentation of Product, Aggregator, and Sub-LAP) and calculated the accuracy and bias of each of the baselines on both day types in program years 2018 and 2019.

Figure 1-1 outlines the comparative analysis and the key steps are described as follows:

Figure 1-1 Description of Analysis Steps



Identifying event days and selecting event-like days. For this analysis, AEG utilized program years 2018 and 2019, identifying event days for both PY2018 and PY2019. Comparable event-like days were selected as part of the ex-post analysis[4] in both program years. Note that to keep comparisons consistent between the three IOUs, we only use event days and event-like days from months May through October.

Calculating baselines. Using the 10-in-10 day matching baseline specified in the CAISO's Baseline Accuracy Work Group Proposal by Nexant[5], we calculated the adjusted baseline estimates for PY2018 and PY2019 event days and event-like days. Six variations of the 10-in-10 day matching baseline were estimated at the customer level, calculating the adjustment ratio at both aggregate and individual levels and applying 20%, 30%, and 40% adjustment caps. We executed the six baselines on three scenarios: (1) event days, wherein the adjusted baselines were calculated for the window that the actual event was called; (2) event-like days assuming three-hour events called from HE17-HE19 or 4 PM to 7 PM; and (3) event-like days assuming two-hour events being called from HE19-HE20 or 6 PM to 8 PM.

The event-like day scenarios were selected to simulate events typically called by CBP as the program continues to align with the Resource Adequacy (RA) window, HE17-HE21 or 4 PM to 9 PM. Note that both event-like day scenarios use the same data, the differences in the results are driven by two factors: (1) the adjustment window (HE13-HE15 v. HE15-HE17), which determines the adjustment ratio; and (2) the event window (HE17-HE19 v. HE19-HE20), which is used to measure accuracy and bias.

Comparing accuracy and bias. AEG summed the baseline estimates by resource and utilized two metrics: (1) the mean absolute percent error (MAPE) for accuracy, and (2) the mean percent error (MPE) for bias. For both metrics, the goal is to be low or very close to zero to ensure more accurate and less biased estimates. In calculating these metrics, the actual load for event-like days is simply the actual load of each day since no event was called on those days. For event days, we defined the actual load as the estimated reference load in the ex-post analysis since we do not know the true value of the load in the absence of an event.

The approach used to do the comparisons was formulated with careful consideration of how the Capacity Bidding Program is implemented. Recall that retail settlement payments for each event day are done at the aggregator level. Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement. Because of the resource nomination component of the CBP tariff, AEG and the IOUs agree that the measure of accuracy and bias should be performed at the resource level, acknowledging that the resource is nominated and dispatched as a unit. The MAPE and MPE metrics presented for each IOU and program tell us, on average, for each resource, how accurate and biased the baseline estimates are

[4] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. B-1.

[5] https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf

compared to the true value for that resource. Simple numerical examples of the comparison approach are shown in Section 2 (Example Calculation).

Key Findings

We summarize the findings of the comparative analysis at the state level, a total of five[6] programs from all three IOUs. Looking at the results at the state level can simplify the decision-making process in determining the most effective and appropriate baseline for retail settlement. The program-level comparisons are presented in Section 3 and show how both the participant population and the timing of event window can drive the effectiveness of the six baselines.

Table 1-1 shows the most effective baseline from all five programs.[7] This summary accounts for each program's two top (or most effective) ranking baselines for both accuracy and bias and shows the strength of their score in parenthesis. For example, looking at all programs and all event-like day scenarios, aggregate baseline with 20% adjustment cap ranked 1st or 2nd in accuracy in 3 out of 5 programs (shown in red text). Similarly, looking at all programs and all scenarios, aggregate baselines (regardless of the adjustment cap) ranked 1st or 2nd in bias in 3.5 out of 5 programs (shown in blue text). Five is the highest possible score, where all five programs favored a specific baseline. One is the lowest score, which indicates that each of the five programs favored different baselines.

Table 1-1 Accuracy and Bias – All Programs

Scenario	Best Accuracy			Least Bias		
	Overall	Ind v. Agg	Adj Cap	Overall	Ind v. Agg	Adj Cap
All Event-like days	**Agg 20% (3)**	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	**Agg (3.5)**	30% (2.2)

Red text and **blue text** used to highlight the example used in the text above.

Looking at Table 1-1, we can conclude the following:

- Aggregate baselines consistently give the least bias, considering all five programs and all scenarios used in this analysis. The 30% adjustment cap also shows the least bias in 2.2 out of 5 programs, considering all scenarios.
- Event-like day scenarios (HE17-HE19 and HE19-HE20 event windows) show better accuracy using aggregate baselines, while the event day scenarios show better accuracy using the individual baselines. All scenarios show better accuracy using a lower adjustment cap (20%).

[6] (1) PG&E Day Ahead; (2) SCE Day Ahead; (3) SCE Day Of; (4) SDG&E Day Ahead; and (5) SDG&E Day Of.

[7] Each program within each IOU bear equal weight in Table 1-1Table 3-1, i.e., SDG&E DA and DO programs both contribute equally in each category.

Note that the event-like day scenarios are highly valuable since the MAPE and MPE, i.e., accuracy and bias, were calculated using actual load data[8].

Because aggregate baselines resulted in the better accuracy and bias overall, we wanted to further explore differences in adjustment caps for only aggregate baselines. Table 1-2 shows the average loss in accuracy and increase in bias when selecting an aggregate baseline for each of the three adjustment caps. For example, looking at event-like day scenarios, if the aggregate baseline with 30% adjustment cap is selected, we see a 0.49% decrease in accuracy and 0.33% increase in bias, on average (shown in red text). Looking at Table 1-2, we see decreases in effectiveness that are all under 2.3%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap. Furthermore, looking at event day scenarios, which show better accuracy using individual baselines, we see that selecting an aggregate baseline approach will result in relatively small "losses", showing 1.47% to 2.28% decreases in accuracy.

Table 1-2 Average Decrease in Effectiveness – Aggregate Baselines

	Lost Accuracy			Increased Bias		
Scenario	**Agg 20%**	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
All Event-like days	0.26%	**0.49%**	0.76%	0.68%	**0.33%**	0.28%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

Red text used to highlight the example used in the text above.

Recommendation and Rationale

As mentioned in the research objectives, the overall goal of this analysis is to determine the most appropriate baseline for retail settlement. The comparative analysis focused on measuring the effectiveness (best accuracy and least bias) of each baseline with careful consideration of how CBP is implemented.

In these recommendations, it is important to keep in mind the following key points:

- Retail settlement payments for each event day are made at the aggregator level.
- Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement.
- A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

Recommendation

AEG recommends selecting the aggregated baseline with a 20% adjustment cap. The aggregate baseline is the most accurate overall, across all scenarios, and is also the most appropriate to the tariff and program implementation. Furthermore, the aggregate baseline with a 20% cap also has the advantage of being the same as the wholesale baseline settlement, which alleviates concerns around mismatches in the retail and wholesale settlement baseline results.

In Table 1-3 below, we present a comparison of both the recommended retail baseline (aggregate with 20% cap) and the current retail baseline (individual with 40% cap). The values shown in the table indicate

[8] The comparisons derived from the event day scenarios are also theoretically valid but come with constraints due to modeling errors in the ex-post analysis.

a ranking out of 6, with 1 ranking the highest (most accurate or least biased) and 6 ranking the lowest. The current baseline ranks 4.4-4.7 out of 6 in accuracy and 3.2-3.6 out of 6 in bias across all programs while the recommended baseline ranks 2.3-3.0 out of 6 in accuracy and 3.6 out of 6 in bias. This indicates that the recommended baseline is more accurate, and similar in bias to the existing baseline.

Table 1-3 Comparison of Recommended vs. Current Retail Baselne – Average Ranking

	Aggregate with 20% Cap		Individual with 40% Cap	
Scenario	**Accuracy Ranking**	**Bias Ranking**	**Accuracy Ranking**	**Bias Ranking**
All Event-like Days	2.3	3.6	4.7	3.6
Event Days	3.0	3.6	4.4	3.2
All Scenarios	2.5	3.6	4.6	3.5

Rationale

In this section we provide more context around our recommendation with respect to the two key aspects for the baseline: (1) individual vs. aggregate; and (2) the adjustment cap.

Comparing Effectiveness Across Baselines

It is important to note that this analysis greatly emphasized how much the participant population and the timing of the event window can influence the effectiveness of the six baselines. The program-level results presented in Section 3 demonstrate how accuracy and bias can swing from year-to-year, depending on these two factors (participant population and event timing).[9]

Fortunately, between the 6 baseline options, both accuracy and bias are not highly sensitive within a single population and program year. In other words, in any given year, the loss of accuracy or bias between individual versus aggregate or between 20%, 30%, and 40% adjustment caps is minimal. This lack of sensitivity is consistent in all program-level program year comparisons (graphs shown in Appendix). Therefore, we believe that additional focus should be placed on the appropriateness of the selected baseline including its alignment with CBP program implementation and coordination with the wholesale baseline.

Individual vs. Aggregate Baselines?

AEG recommends that the Aggregate Baseline be used for retail settlement with the following reasons:

- Aggregate baselines, regardless of the adjustment cap, consistently minimizes the bias. Across all scenarios, all five programs and two program years, aggregate baselines show less biased adjusted baseline estimates.
- Looking only at the event-like day scenarios, aggregate baseline, regardless of the adjustment cap, give the best accuracy across all five programs and two programs years. The event-like day scenarios also hold more weight since the accuracy and bias are measured relative to actual load data.

[9] The most illustrative example from this analysis is shown in Figure A-17 and Figure A-18, which show SDG&E's PY2018 Day Of Program. Looking at the event-like day scenarios, notice how the MAPE and MPE are extremely high when the event is called from HE17-HE19 compared to when the event is called from HE19-HE20. Note that these two scenarios use the exact same participants and data, i.e., the event-like days and the 10 baseline days are the same in both scenarios.

- The aggregate baseline treats the resource as a unit, instead of looking at customers individually, by determining the adjustment ratio at the resource level. The resource, as discussed above, is a key factor in how CBP is implemented.
  - It is important to note that customer-level calculations are important to aggregators and can still be provided when the aggregate baseline is implemented.

	Pros	Cons
Individual Baselines	• Provides more accurate estimates for individual customers.	• Provides less accurate estimates at the resource level. • Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	• Provides more accurate estimates at the resource level. • Aligns with the wholesale settlement baseline.	• Provides less accurate estimates for individual customers.

Which adjustment cap is the most appropriate?

State-level results show that the 20% adjustment cap gives adjusted baseline estimates with the best accuracy, while the 30% adjustment cap gives the least bias. However, both accuracy and bias are not highly sensitive to the adjustment cap. We see such small differences in accuracy and bias between the 20%, 30%, and 40% caps that selecting one over the other does not mean a significant loss in effectiveness. Given that the wholesale baseline already uses a 20% adjustment cap, the advantages of aligning the two caps far outweigh the very small increase in bias.

2

STUDY METHODS

This section presents the methods employed in this study. In the first section, we describe the prescribed approach used to calculate the six variations of the 10-in-10 day matching baseline. In the second section, we describe the comparative analysis that was used to compare the six baselines.

The main goal of this analysis was to identify the most effective baseline to represent the counterfactual, or what would have happened in absence of an event, with respect to accuracy and bias.

Calculating the 10-in-10 Day Matching Baseline

The 10-in-10 day matching baseline calculation was estimated according to the CAISO's Baseline Accuracy Work Group Proposal by Nexant using each of the six variations below:[10]

- Aggregate 10-in-10 day matching with maximum 20% day-of adjustment,
- Aggregate 10-in-10 day matching with maximum 30% day-of adjustment,
- Aggregate 10-in-10 day matching with maximum 40% day-of adjustment,
- Individual 10-in-10 day matching with maximum 20% day-of adjustment,
- Individual 10-in-10 day matching with maximum 30% day-of adjustment,
- Individual 10-in-10 day matching with maximum 40% day-of adjustment.

Note that in this analysis, the aggregate level is defined as the combined segmentation of Product, Aggregator, and Sub-LAP. This is to create a comparable simulation to the wholesale settlement baseline, which defines the aggregate level at the resource level.

The calculation was completed by following the steps outlined below. Note that steps 2 through 5 are italicized. They are included in the official definition of the day matching baseline, but since all 10 of 10 eligible days are selected for the baseline calculation, the ranking and selection (covered in steps 2 through 5) are unnecessary. Furthermore, step 10 was not completed as part of this analysis since the comparisons were done on the adjusted baseline estimates, which is calculated in step 9.

1. Identify the 10 eligible baseline days that occurred prior to an event, excluding weekends, other event days, ISO holidays, award dates, outages, etc.
2. *Calculate the hourly participant load for the event day and for each eligible baseline day.*
3. *Calculate total MWh during the event period for each eligible baseline day.*
4. *Rank the baseline days from largest to smallest based on MWh consumed over the event period.*
5. *Select the top ten baseline days out of the pool of eligible days.*
6. Average hourly customer loads across the ten baseline days to generate the unadjusted baseline.
7. Calculate the day-of adjustment ratio (at aggregate or individual level) based on the adjustment window: three hours immediately prior to the event with a one-hour buffer.

[10] https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf

$$Adjustment\ ratio = \frac{Total\ kWh\ during\ adjustment\ hours}{Unadjusted\ baseline\ kWh\ over\ adjustment\ hours}$$

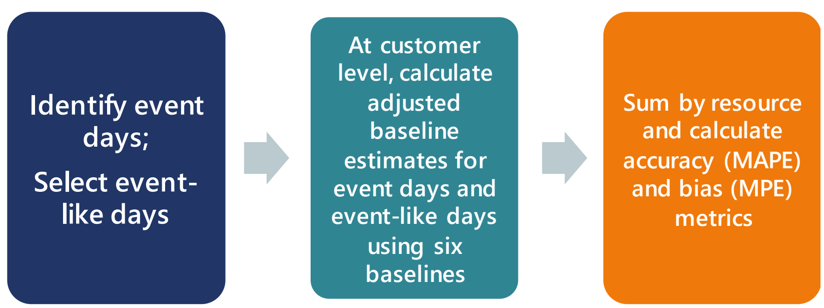
8. If the day-of adjustment ratio exceeds adjustment cap, limit the adjustment ratio to the cap, where X can be 20%, 30%, 40%. The adjustment cap is up =1+X and down =1-X.
9. Apply the day-of adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline estimate.
10. Calculate the Actual Load Reduction as the difference between the adjusted baseline and actual electricity use for each event hour.

Note that a key distinction between the baselines occurs in step 7. The day-of adjustment ratio for an individual baseline is calculated at the customer level, i.e., for each customer and event day. However, for an aggregate baseline, the day-of adjustment ratio is calculated at the aggregate level, i.e., for each resource and event day.

Comparative Analysis

Figure 2-1, to the right, outlines the comparative analysis that was performed to identify the most effective baseline. We discuss each step in detail in the following subsections. Note that the selection of event-like days was completed as part of the ex-post impact analyses in PY2018 and PY2019. [11]

Figure 2-1 Description of Analysis Steps



In this hypothetical comparative analysis, AEG calculated adjusted baseline estimates for each of the six baselines described above on both event days and event-like days at the customer level. Then, AEG summed the adjusted baseline estimates to the resource level (segmentation of Product, Aggregator, and Sub-LAP) and calculated the accuracy and bias of each of the baselines on both day types in program years 2018 and 2019 as follows:

- On event-like days we measure the effectiveness of each baseline (using accuracy and bias) by comparing the adjusted baseline estimate to the actual event-like day load where both represent a counterfactual, or what would have happened on an event-day in absence of an event.
- We conducted a similar comparison on event days; however, we used the reference load from the ex-post analysis as the reference point to measure accuracy and bias. The reference load is used in this comparison since it is the counterfactual produced by the ex-post models.[12]

Selecting Event-Like Days

To select the event-like days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. To determine how close event day temperature is to a potential event-like day, we calculated a Euclidean distance metric defined as the square root of

[11] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. B-1.
[12] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. 8.

the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance; in PY2018 and PY2019, we used three different Euclidean distance metrics to select similar non-event days: (1) daily maximum temperature; (2) average daily and daily maximum temperatures; (3) average daily temperature. The Euclidean distance metrics used can be calculated by Equations 1 through 3 below.

$$ED_1 = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2} \quad (1)$$

$$ED_2 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2 + (MaxTemp_{event} - MaxTemp_{non-event})^2} \quad (2)$$

$$ED_3 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2} \quad (3)$$

Since all three IOUs called several different event windows, we placed the focus on the entire day instead of a specific event window. Because we limited the pool to within-year non-event days, we selected less non-event days for each program year analysis to accommodate both the non-event day pool and the available customer data. To ensure that we selected an adequate group of event-like days, we do a final check and compare the distributions of weather and day types. For example, if there are more event days in August and more event days on a Tuesday, we try to account for that in the selected event-like days.

In the figures below, we show comparisons of the distributions of average daily temperature of event days and event-like days. We show one comparison for each utility by program year, because the selection was done at the utility level instead of the program or product level. We use this approach to accommodate customer moves between products or programs and the automation process of running individual customer regression models.

Figure 2-2 PG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

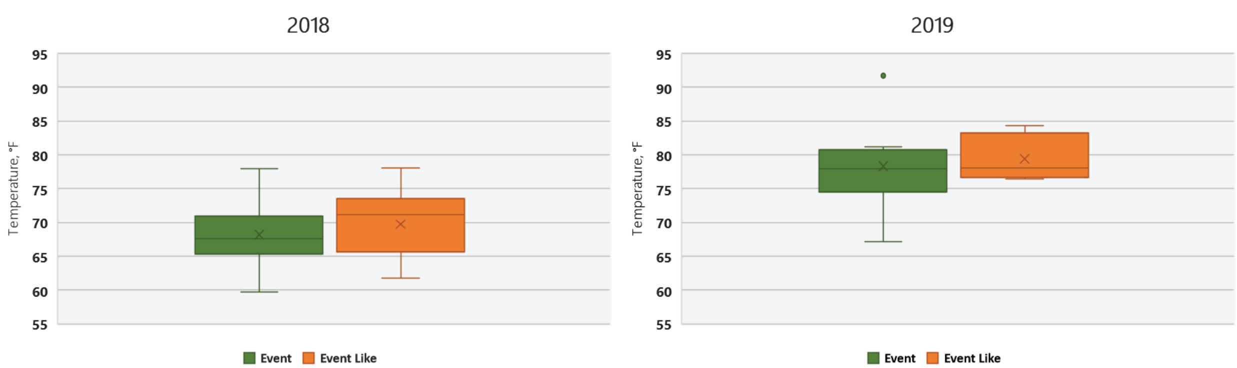


Figure 2-3 SCE Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

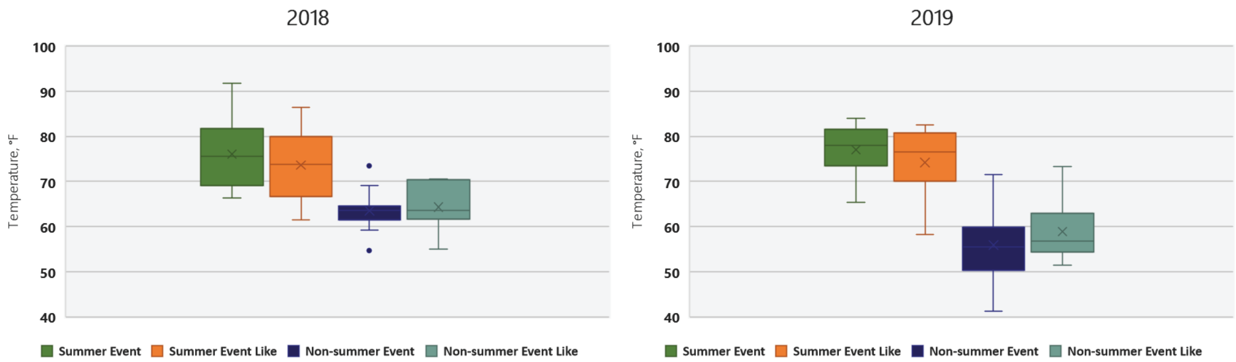
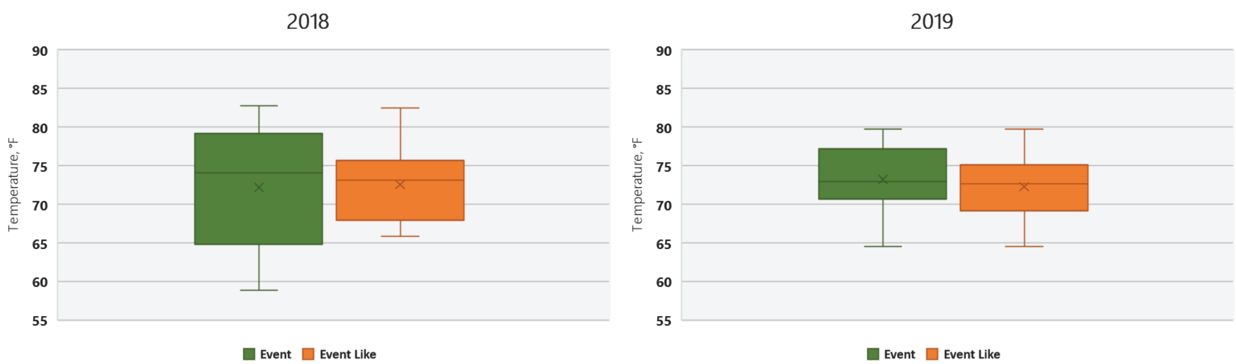


Figure 2-4 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019



Calculating the Baselines

Using the 10-in-10 day matching baseline methodology discussed above, we calculated the six baselines[13] for three scenarios resulting in 18 individual calculations:

- Event days in PY2018 and PY2019 over the actual event window.
- Event-like days in PY2018 and PY2019 assuming three-hour events were called from HE17-HE19 or 4 PM to 7 PM.
- Event like days in PY2018 and PY2019 assuming two-hour events were called from HE19-HE20 or 6 PM to 8 PM.

The event-like day scenarios were selected to simulate events typically called by CBP as the program continues to align with the Resource Adequacy (RA) window, HE17-HE21 or 4 PM to 9 PM. Note that both event-like day scenarios use the same data, the differences in the results are driven by two factors: (1) the adjustment window (HE13-HE15 v. HE15-HE17), which determines the adjustment ratio; and (2) the event window (HE17-HE19 v. HE19-HE20), which is used to measure accuracy and bias.

[13] We estimated the baselines for six variations, calculating the adjustment ratio at both aggregate and individual levels, applying 20%, 30%, and 40% adjustment caps.

Calculating Accuracy and Bias

Once we calculated the six baselines for each of the three scenarios, we compared the various estimates using measures of accuracy and bias. The mean absolute percent error (MAPE) measures accuracy, which is the measure of how close the estimate is to the known value. The mean percent error (MPE) measures bias, which is when estimates are always higher or lower than the known value. Equations (4) and (5) show the MAPE and MPE, respectively.

$$MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right| \tag{4}$$

$$MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h} \tag{5}$$

For both metrics, the goal is be low or very close to zero to ensure high accuracy or low bias estimates.

The actual load for event-like days ($Actual_h$in Equations 4 and 5) is simply the load on each day since no event was called on those days. For event days, we defined the actual load as the estimated reference load in the ex-post analysis since we do not know the true value of the load in the absence of an event.

To compare the six baselines, AEG calculated the MAPE and MPE at the simulated resource level, which is the combination of product, aggregator, and sub-LAP. In doing so, we are establishing an apples-to-apples comparison between the six baselines for each scenario, where in the MAPE and MPE point estimates tell us, on average, for a resource, how close is the estimated baseline to the true value for that group. In the next section, we will also discuss further the rationale behind the comparison approach.

Example Calculation

An important distinction in the analysis is the difference between the individual baseline and the aggregate baseline. Below, Table 2-1 provides a simple numerical example of how the MAPE and MPE are calculated for an individual baseline estimate vs. an aggregate baseline estimate for a single ratio cap value. The example includes two resources, Resource 1 with three customers, and Resource 2 with only a single customer. The adjustment ratios for customers in Resource 1 (shown in red text) illustrate the differences between the individual and aggregate baselines. The method score (highlighted in blue) compares the effectiveness of the two baselines.

Table 2-1 Resource-level Comparison: Calculation Example

	Individual Baseline				Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

	Aggregate Baseline				Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- The MAPE and MPE are calculated for each resource and event day. The average MAPE and MPE for each IOU and program (Day Ahead or Day Of) is calculated to achieve the accuracy and bias score for each of the six baselines. In this approach, each resource and event day is given equal weight in each IOU and program.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text). In the individual baseline method, the adjustment ratio is determined at the customer level, while in the aggregate baseline method, the adjustment ratio is determined at the aggregate level.
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.

Exclusions

During review of results and discussions with the IOUs, AEG excluded the data points that met the following criteria:

- Negative MAPE – this occurs only in the event day scenarios and is caused by negative values in the ex-post estimated reference load. This indicates significant modeling errors in the ex-post regression models.
- Missing MAPE or MPE – this is caused by missing hourly usage data.
- Outlier MAPE – outliers were determined by looking at the distribution of the MAPE at the customer level by IOU and program, identifying customers and events with highly erratic loads. This criterion excluded four customers from all three IOUs and around 1% of total data.

3

RESULTS AND COMPARISONS

The comparisons presented in this section were derived using the approach described in Section 2,Calculating Accuracy and Bias. The approach used to do the comparisons in this analysis was formulated with careful consideration of how the Capacity Bidding Program is implemented.

Recall that retail settlement payments for each event day are done at the aggregator level. Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement. So, in theory, aggregators can collectively nominate 10 customers as a resource for 2 MW curtailment, but on any given event, only dispatch 3 out of the 10 customers to deliver the 2 MW curtailment.

Because of the resource nomination component of the CBP tariff, AEG and the IOUs agree that the measure of accuracy and bias should be performed at the resource level, acknowledging that the resource is nominated and dispatched as a unit.

Summary of Findings

The following section discusses the results at the State level, i.e., for all IOUs and programs, five[14] programs altogether.

Event-like Day Results

In this subsection, we discuss the "winning" baseline, looking only at the event-like day scenarios. We find the results from these scenarios highly valuable since the MAPE and MPE, i.e., accuracy and bias, were calculated using actual load data[15]. In these simulations, we are testing how effectively the six variations of the 10-in-10 day matching baselines estimate the actual load of the event window.

Table 3-1 shows the most effective baseline from the five programs.[16] This summary accounts for each program's two top (or most effective) ranking baselines for both accuracy and bias and shows the strength of their score in parenthesis. For example, looking at all programs and all event-like day scenarios, aggregate baseline with 20% adjustment cap ranked 1st or 2nd in accuracy in 3 out of 5 programs (shown in red text). Similarly, looking at all programs and event-like day HE17-HE19 scenarios, aggregate baseline (regardless of the adjustment cap) ranked 1st or 2nd in bias in 3 out of 5 programs (shown in blue text). Five is the highest possible score, where all five programs favored a specific baseline. One is the lowest score, which indicates that each of the five programs favored different baselines.

Looking at Table 3-1, we can conclude the following:

- Aggregate baselines, regardless of the adjustment cap, give estimates with better accuracy and less bias.
- The lower adjustment cap (20%) gives estimates with the better accuracy, however the higher adjustment caps (30% and 40%) minimize the bias.

[14] (1) PG&E Day Ahead; (2) SCE Day Ahead; (3) SCE Day Of; (4) SDG&E Day Ahead; and (5) SDG&E Day Of.

[15] The comparisons derived from the event day scenarios are also theoretically valid but come with constraints due to modeling errors in the ex-post analysis.

[16] Each program within each IOU bear equal weight in Table 3-1, i.e., SDG&E DA and DO programs both contribute equally in each category.

Because aggregate baselines resulted in the better accuracy and bias overall, we wanted to further explore differences in adjustment caps for only aggregate baselines. Table 3-2 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline. For example, if the 30% adjustment cap is selected, we see a 0.49% decrease in accuracy and 0.33% increase in bias, for both HE17-HE19 and HE19-HE20 event windows, on average (shown in red text). Looking at Table 3-2, we see decreases in effectiveness that are all under 1%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.

Table 3-1 Accuracy and Bias – Event-like Day Scenarios

Event-like Day Scenario	Best Accuracy			Least Bias		
	Overall*	**Ind v. Agg***	**Adj Cap**	**Overall***	**Ind v. Agg**	**Adj Cap**
Event-like Days (HE17-HE19)	Agg 20% Agg 30% (3)	Agg (4)	20% (2.5)	Agg 30% Agg 40% (3)	**Agg (3)**	40% (2.5)
Event-like Days (HE19-HE20)	Agg 20% Ind 20% (3)	Ind, Agg (2.5)	20% (3)	Agg 30% (5)	Agg (4.5)	30% (3)
All Event-like days	**Agg 20% (3)**	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)

Red text and **blue text** used to highlight the example used in the text above.

Table 3-2 Average Decrease in Effectiveness – Event-like Days – Aggregate Baselines

Event-like Day Scenario	Lost Accuracy			Increased Bias		
	Agg 20%	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
Event-like Days (HE17-HE19)	0.24%	0.49%	0.78%	0.76%	0.46%	0.38%
Event-like Days (HE19-HE20)	0.27%	0.48%	0.75%	0.59%	0.21%	0.18%
All Event-like days	0.26%	**0.49%**	0.76%	0.68%	**0.33%**	0.28%

Red text used to highlight the example used in the text above.

Results for All Scenarios

Similar to the previous subsection, Table 3-3 shows the most effective baseline from all three IOUs and programs, looking at only event days and all three scenarios overall, and Table 3-4 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline.

Comparisons on the event day scenarios shift the results to show better accuracy using the individual baselines. However, the aggregate baselines still show the least bias, consistent with the event-like day scenarios. The event day scenarios also show higher decreases in effectiveness when selecting the aggregate baseline, on average, but they are still relatively small with all decreases under 3%.

When looking at all scenarios, the aggregate baseline methodology, regardless of the adjustment cap, still gives estimates with better accuracy and less bias, showing very low decreases in effectiveness, all under 1.3%, on average.

Table 3-3 Accuracy and Bias – Event Days and Overall

	Best Accuracy			Least Bias		
Scenario	Overall	Ind v. Agg	Adj Cap	Overall	Ind v. Agg	Adj Cap
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	Agg (3.5)	30% (2.2)

Table 3-4 Average Decrease in Effectiveness – Event Days and Overall – Aggregate Baselines

	Lost Accuracy			Increased Bias		
Scenario	Agg 20%	Agg 30%	Agg 40%	Agg 20%	Agg 30%	Agg 40%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

As mentioned in the Section 1 (Research Objectives), one of the issues for investigation in this analysis is to consider whether the wholesale and retail baselines should be aligned or if they can be different. In Table 3-5 below we present a comparison of both the current wholesale baseline (aggregate with 20% cap) and the current retail baseline (individual with 40% cap). The values shown in the table indicate a ranking out of 6, with 1 ranking the highest (most accurate or least biased) and 6 ranking the lowest. The current retail baseline ranks 4.4-4.7 out of 6 in accuracy and 3.2-3.6 out of 6 in bias across all programs while the current wholesale baseline ranks 2.3-3.0 out of 6 in accuracy and 3.6 out of 6 in bias. This indicates that aligning the wholesale and retail baselines to both be aggregate baselines with 20% cap would result in more accurate estimates and similar bias, at the resource level.

Table 3-5 Comparison of Current Wholesale Baseline vs. Current Retail Baselne – Average Ranking

	Aggregate with 20% Cap		Individual with 40% Cap	
Scenario	Accuracy Ranking	Bias Ranking	Accuracy Ranking	Bias Ranking
All Event-like Days	2.3	3.6	4.7	3.6
Event Days	3.0	3.6	4.4	3.2
All Scenarios	2.5	3.6	4.6	3.5

Program-level Comparisons

In this subsection, we present the comparisons by program for all three IOUs. Each program will have two graphs, all following a uniformed color scheme: blue for accuracy and orange for bias. In addition, each graph will have the following components:

- A separate block, indicating each of the three event scenarios: (1) Event days; (2) Event-like days assuming HE17-HE19 event window; and (3) Event-like days assuming HE19-HE20 event window.
- The best score for each scenario shown in red text and red box.
- The current retail settlement baseline (Individual Baselines with 40% adjustment cap) shown in a striped pattern fill.

The program-level comparisons show how both the participant population and the timing of event window can drive the effectiveness of the six baselines.

PG&E Results

Starting in PY2018, PG&E only offers Day Ahead product offerings.

Day Ahead Program

The DA program results cover 55 event days and 29 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 12 unique resources and 948 unique customers. Figure 3-1 and Figure 3-2 show the accuracy and bias comparison for all three scenarios, respectively.

For PG&E DA, we can conclude the following:

- The event-like day scenarios show consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline has low sensitivity to the timing of the event window (HE17-HE19 v. HE19-HE20).
  - The two event-like day scenarios have very consistent bias comparisons, showing less bias using the aggregate baseline (dark orange bars are consistently lower), with the 40% adjustment cap showing the least bias in both individual and aggregate baselines. The event-like days also show all positive MPE estimates, indicating that the estimates are lower, on average, than the actual event-like day loads.
  - Looking at accuracy, the HE17-HE19 event window show results consistent to bias, showing the best accuracy using the aggregate baseline with 40% adjustment cap.
  - The HE19-HE20 event window simulation shows slightly different accuracy results, with the individual baselines showing better accuracy. Also note that the aggregate baseline with 40% adjustment cap shows the lowest accuracy. This is due to the results from PY2018 event-like days (see Figure A-1 and Figure A-3), which is an indicator that the customer mix, i.e., population distribution, can largely influence the effectiveness of the baseline.
- The event days show results comparable to the HE19-HE20 event-like day scenarios, despite the differences in magnitude, showing better accuracy using the individual baselines. This is due to PG&E DA calling 30 out of 55 events that start on HE19. It is also interesting to note that the event days show the 20% adjustment cap to perform the highest effectiveness.

Figure 3-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level

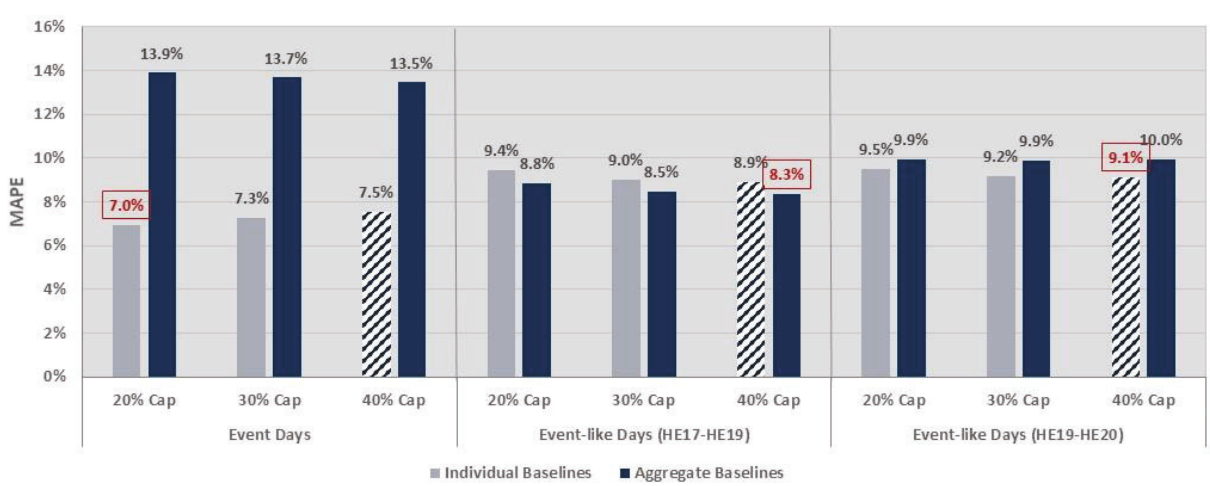
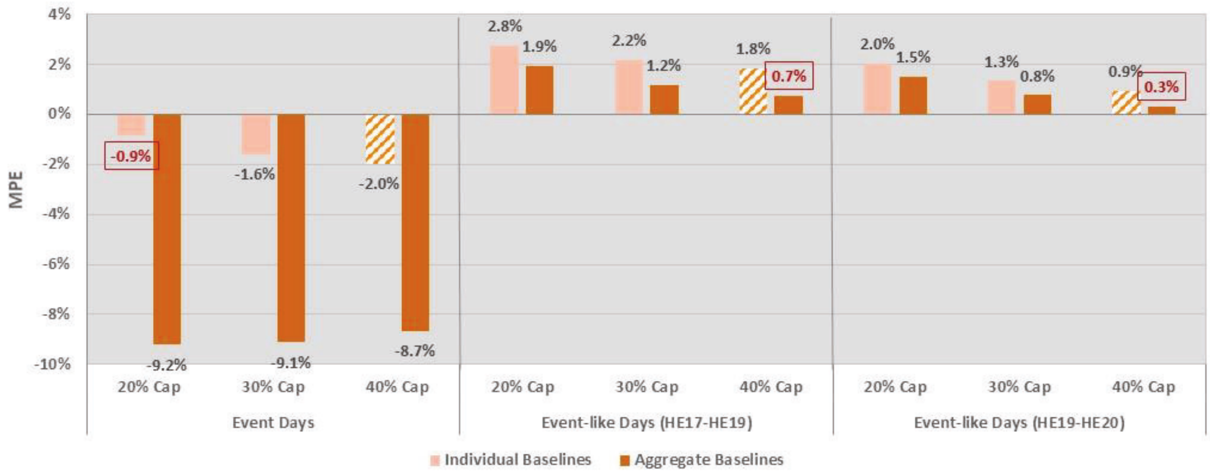


Figure 3-2 PG&E Day Ahead Program: Bias Comparison – Resource-level



SCE Results

Day Ahead Program

The DA program results cover 44 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes five unique resources and 385 unique customers. Figure 3-3 and Figure 3-4 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DA, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20).
    - The two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower), with the 40% adjustment cap showing the best accuracy and least bias in both individual and aggregate baselines.
    - The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.
- The event days show conflicting results, and this is largely driven by the PY2018 results (shown in Figure A-5), which show the best effectiveness using the individual baselines with 20% adjustment cap. The PY2019 event day comparisons, however, show results more consistent with the event-like days, showing the best accuracy using the aggregate baseline with 40% adjustment cap. It is also interesting to note that the PY2019 event days show the 20% adjustment cap to give the least bias.

Figure 3-3 SCE Day Ahead Program: Accuracy Comparison – Resource-level

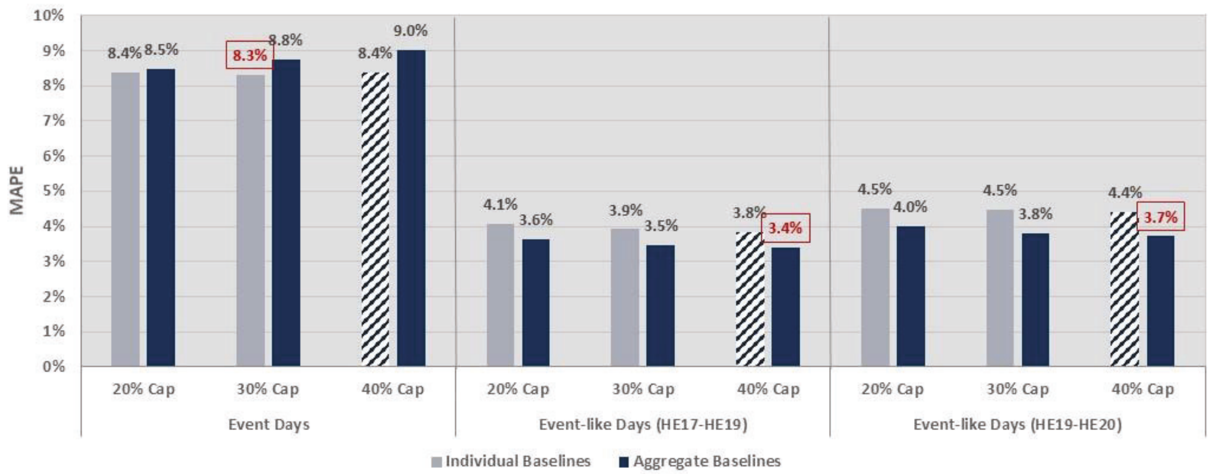
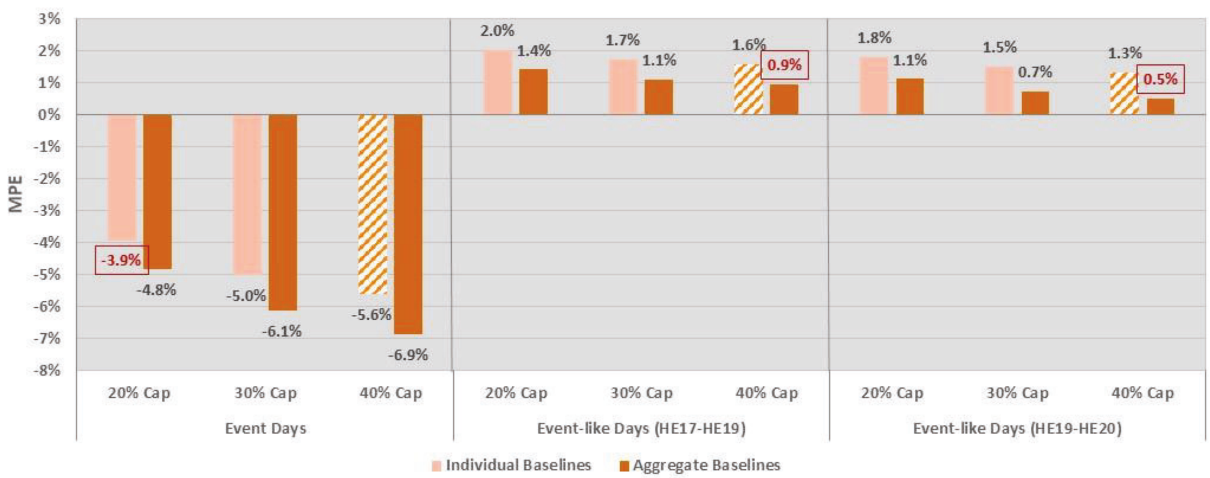


Figure 3-4 SCE Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 49 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 6 unique resources and 368 unique customers. Figure 3-5 and Figure 3-6 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DO, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20).
    - Like SCE DA, the two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower). However, the 20% adjustment cap shows the best accuracy, while the higher adjustment caps (30% and 40%) show less bias in both individual and aggregate baselines.

- The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.

- Similar to PG&E DA, the event days show results comparable to the HE19-HE20 event-like day scenario, showing better accuracy using the individual baselines. This is due to SCE DO calling 38 out of 49 events that start on HE19. Also comparable to the HE19-HE20 event-like day scenario, individual baseline with 20% adjustment cap gives the most bias.

Figure 3-5 SCE Day Of Program: Accuracy Comparison – Resource-level

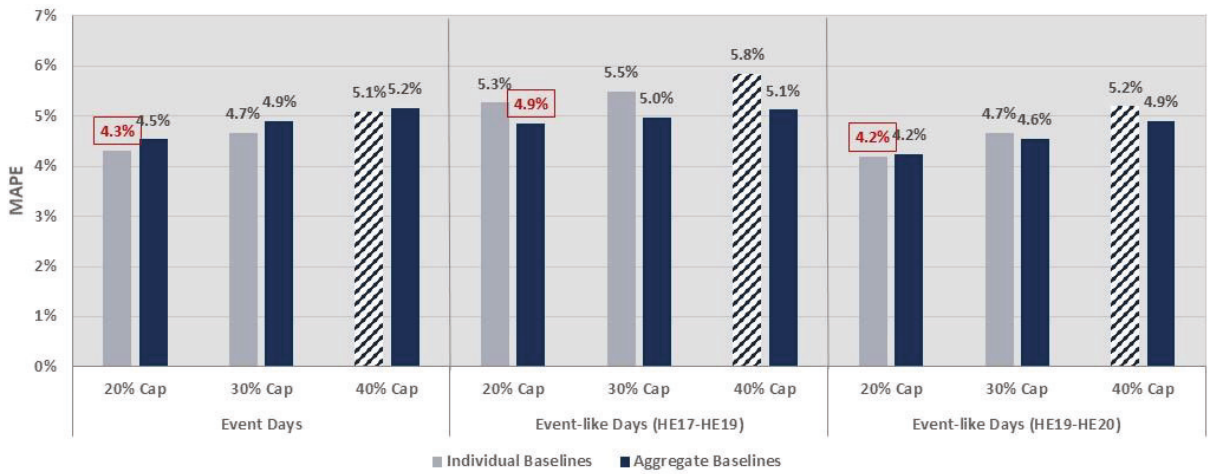
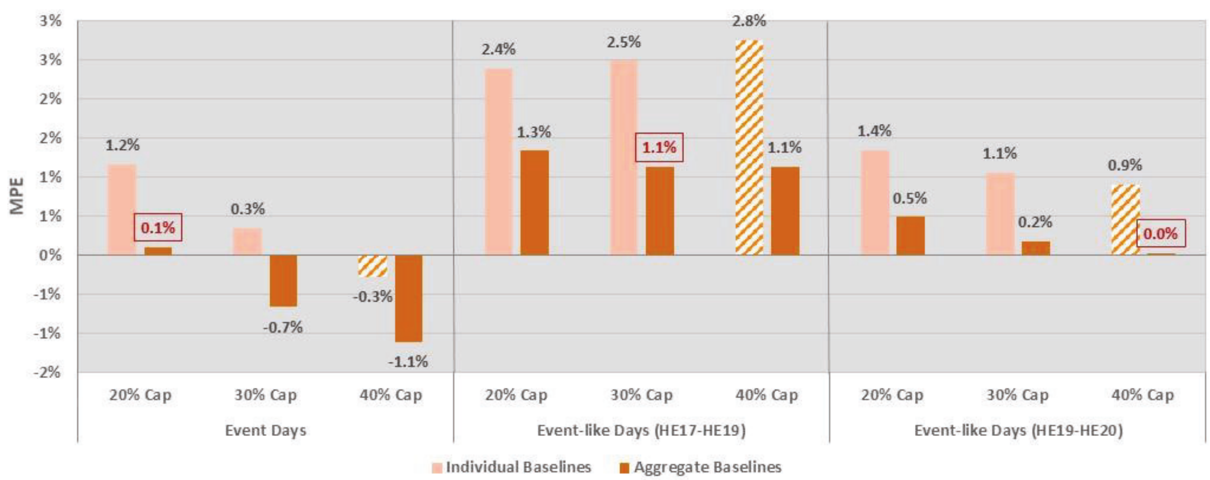


Figure 3-6 SCE Day Of Program: Bias Comparison – Resource-level



SDG&E Results

Day Ahead Program

The DA program results cover 48 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DA program includes seven unique resources and 75 unique customers. Figure 3-7 and Figure 3-8 the accuracy and bias comparison for all three scenarios, respectively.

For SDG&E DA, PY2018 and PY2019 have some conflicting results, and these are apparent in the overall comparisons. Recall that SDG&E DA experienced large customer unenrollment in the middle of PY2018.

All PY2018 participants are included in the event-like day scenarios regardless of mid-year unenrollment, thus the drastic change in the participant population between PY2018 and PY2019 ultimately drives the differences in the results. Referring to the program year graphs will be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-13 through Figure A-16.

- All scenarios show consistent accuracy results but conflicting bias results. This is largely driven by conflicting bias results from the two program years.
- For event-like days, this indicates that the accuracy of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20). On the other hand, bias comparisons show some sensitivity to the timing of the event window.
  - The two event-like day scenarios have very consistent accuracy comparisons, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines.
  - Looking at bias, the event-like day scenarios show very conflicting results. In this case, it may be helpful to only look at PY2019 results (shown in Figure A-16), since it is more representative of the participant population in future years. PY2019 bias comparisons for SDG&E DA also show less bias using the individual baseline (light orange bars are consistently lower). However, the effect of the adjustment cap is different in the two event window simulations, showing least bias at 40% adjustment cap for HE17-HE19 events and least bias at 20% adjustment cap for HE19-HE20 events.
- Similar to the event-like day scenarios, the event days show better accuracy using the 20% adjustment cap, but instead showing better accuracy using the aggregate baseline (dark blue bars are consistently lower). Again, we see conflicting bias results for the event days. Thus looking only at PY2019 results (shown in Figure A-16), we see less bias using the aggregate baseline (dark orange bars are lower) and the least bias using the 20% adjustment cap.

Figure 3-7 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level

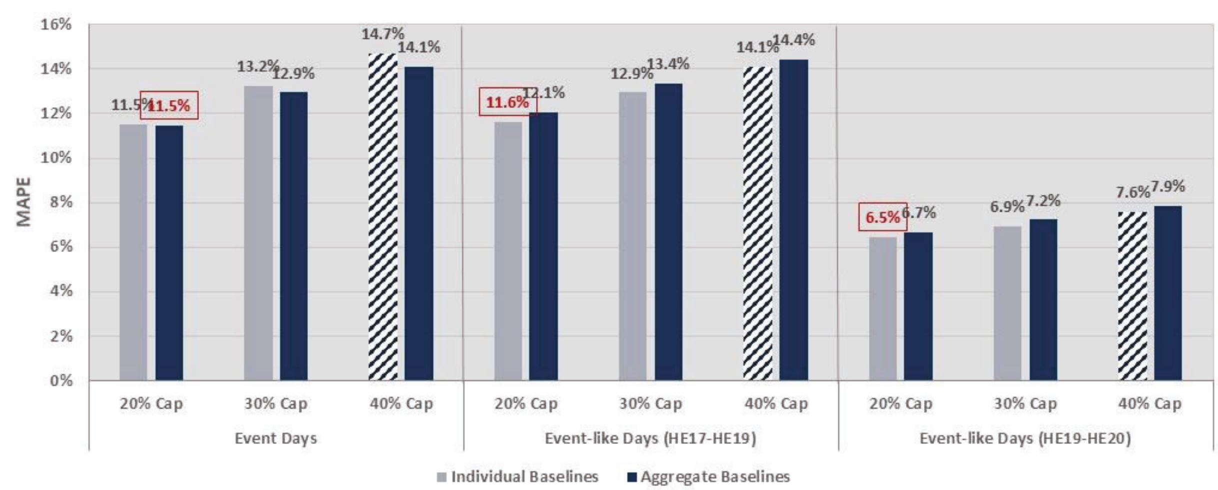
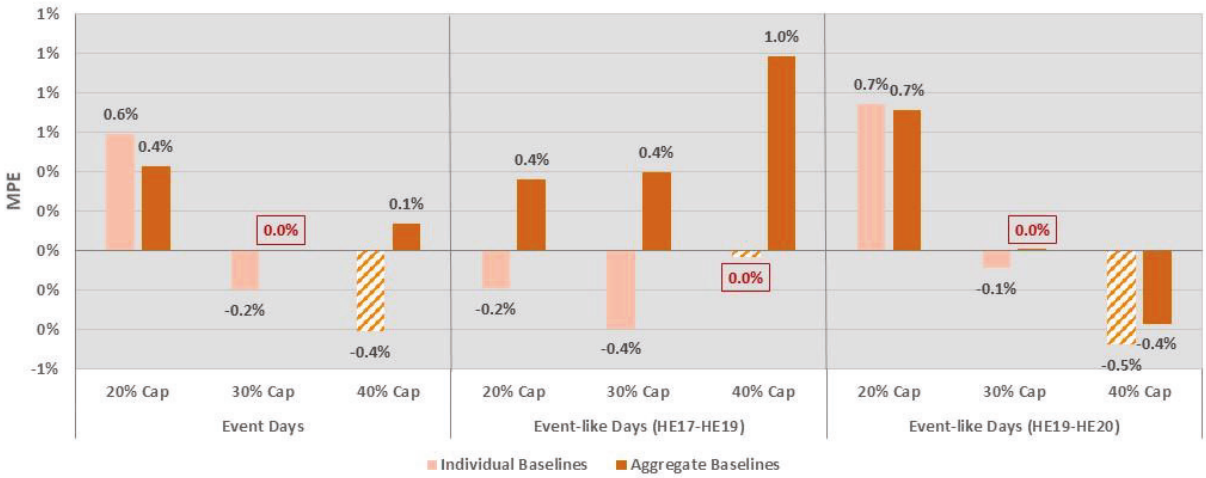


Figure 3-8 SDG&E Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 19 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DO program includes seven unique resources and 201 unique customers. Figure 3-9 and Figure 3-10 show the accuracy and bias comparison for all three scenarios, respectively.

SDG&E DO did not experience a drastic participant turnover in PY2018 and PY2019, thus we do not see the same results like in SDG&E DA. However, looking at the event-like day comparisons, the overall results for both program years seem to indicate the sensitivity to the timing of the event window. This is also driven by conflicting results from PY2018 and PY2019 and referring to the program year graphs will also be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-17 through Figure A-16.

- The event-like day comparisons for PY2018 and PY2019 show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) indicate that both accuracy and bias of the baselines are sensitive to the timing of the event window. However, recall that SDG&E DO only called 3 events in PY2018, all starting on HE18 and that event-like days were selected to be the most comparable to events. It is possible that PY2018 participants have highly variable loads during HE17-HE19 even on non-event days, making it difficult to effectively estimate the event window load through the 10-in-10 day matching baseline.
  - PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results between the two event-like day scenarios. Both event window scenarios show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.
- The event day comparisons for PY2018 and PY2019 also show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) have results consistent with PY2018 event-like days with HE19-HE20 event windows, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Again, likely driven by the combination of events called in PY2018 and typical participant loads during HE18-HE21.

- PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results with the two event-like day scenarios. In PY2019, SDG&E DO called a comparable number of events starting on HE17 and HE18. PY2019 events show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.

Figure 3-9 SDG&E Day Of Program: Accuracy Comparison – Resource-level

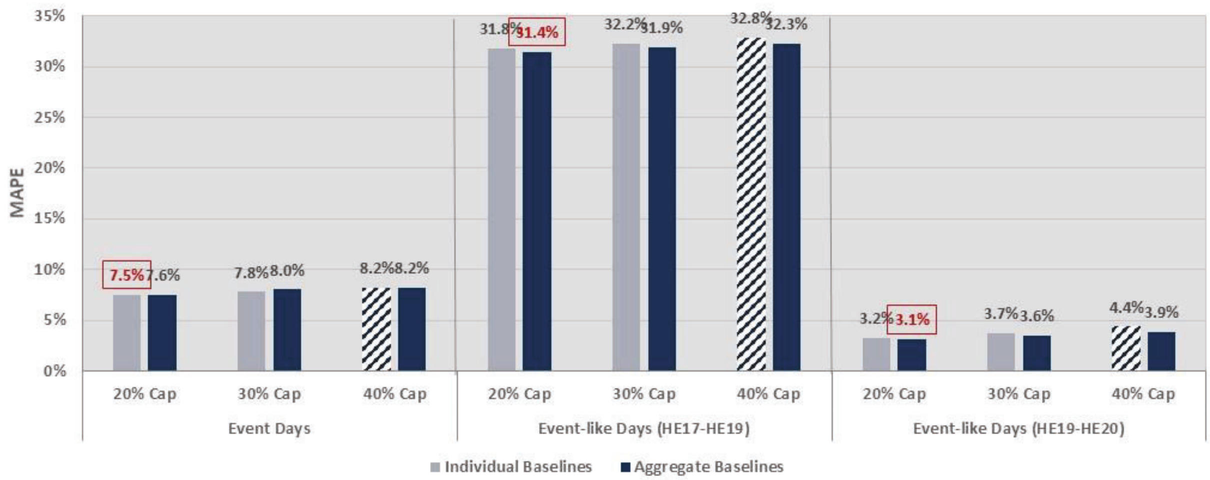
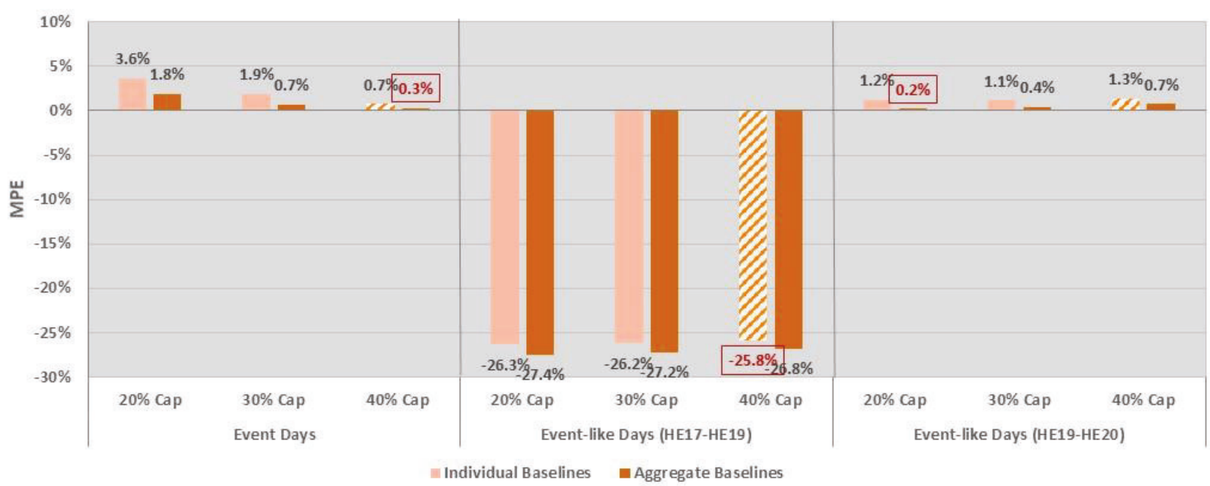


Figure 3-10 SDG&E Day Of Program: Bias Comparison – Resource-level



A

ADDITIONAL TABLES AND GRAPHS

PG&E Results by Program Year

Day Ahead Program

The PG&E DA program PY2018 results cover 46 event days and 23 event-like days and include 11 unique resources and 561 unique customers.

Figure A-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

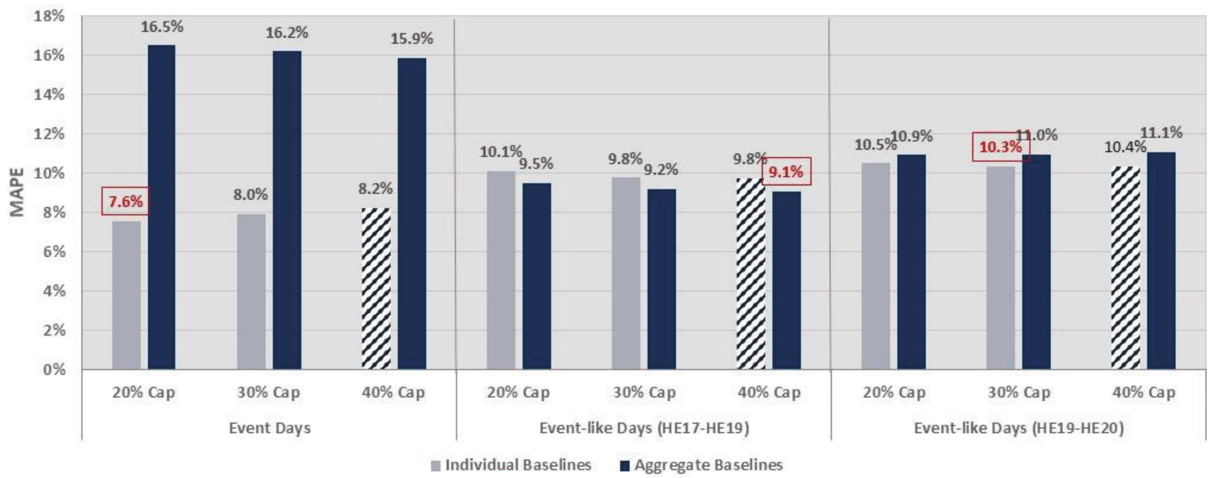
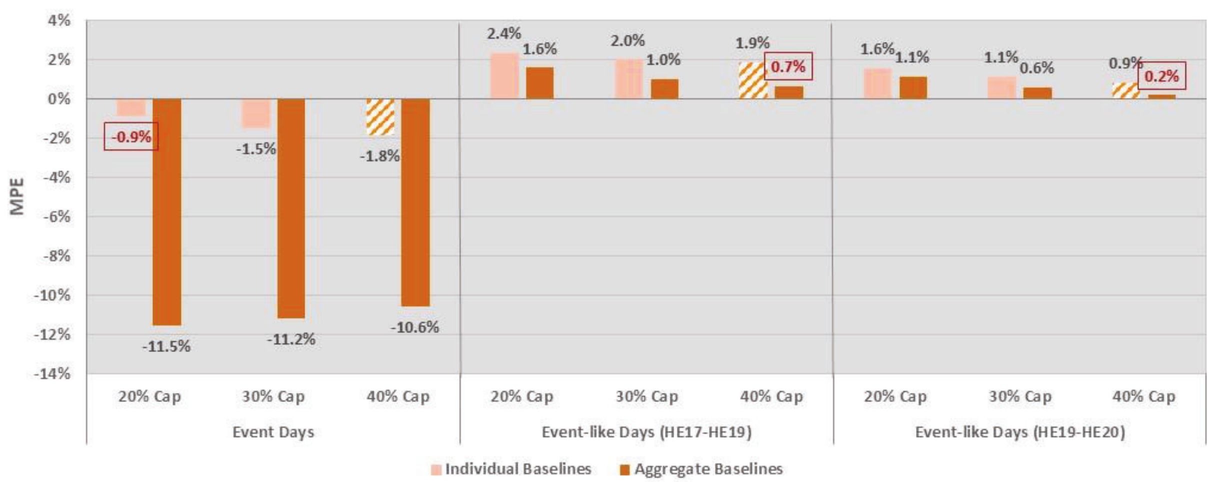


Figure A-2 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The PG&E DA program PY2019 results cover 9 event days and 6 event-like days and include 10 unique resources and 793 unique customers.

Figure A-3 PG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

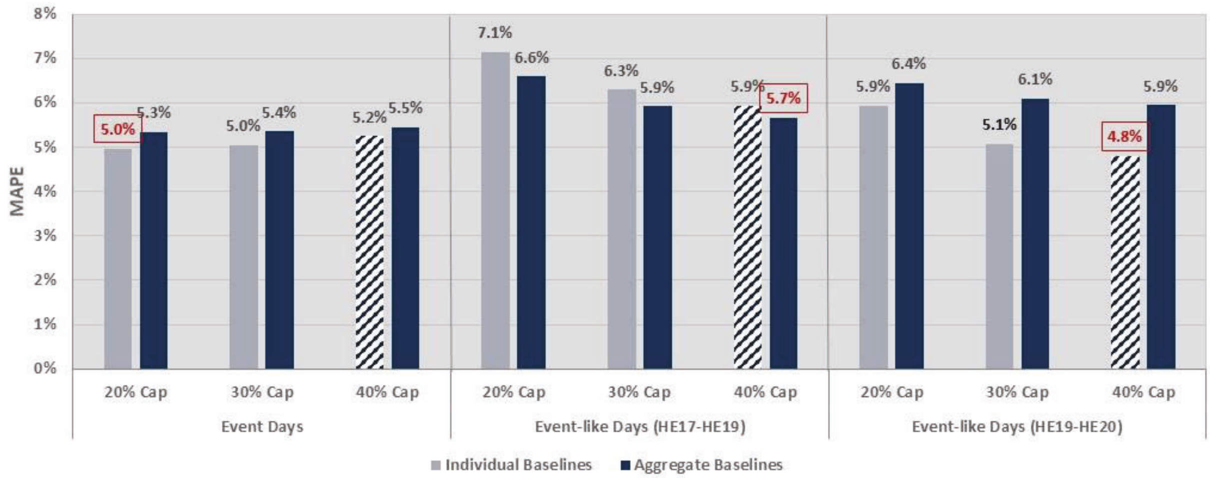
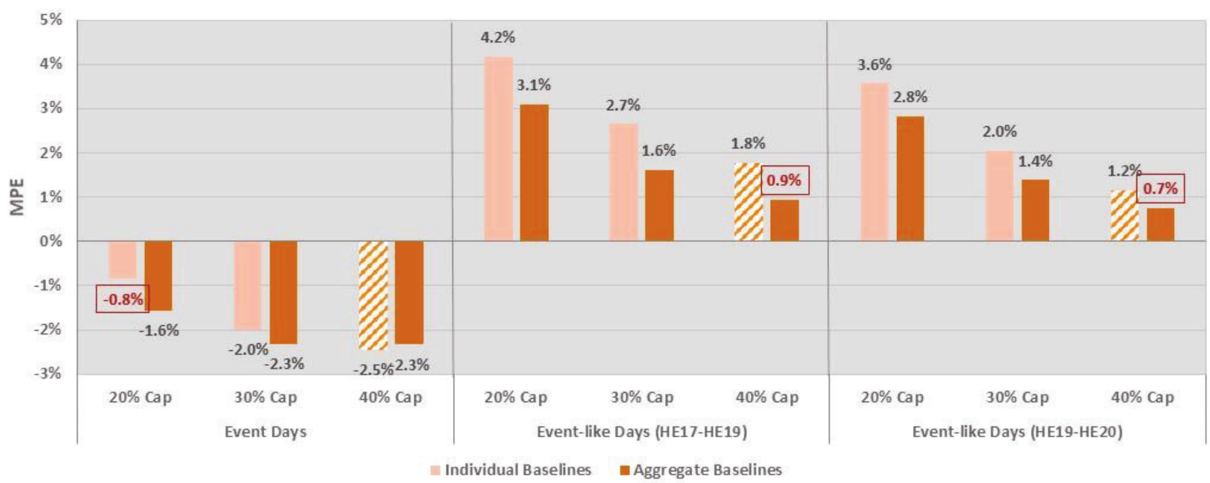


Figure A-4 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



SCE Results by Program Year

Day Ahead Program

The SCE DA program PY2018 results cover 23 event days and 29 event-like days and include 3 unique resources and 74 unique customers.

Figure A-5 SCE Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

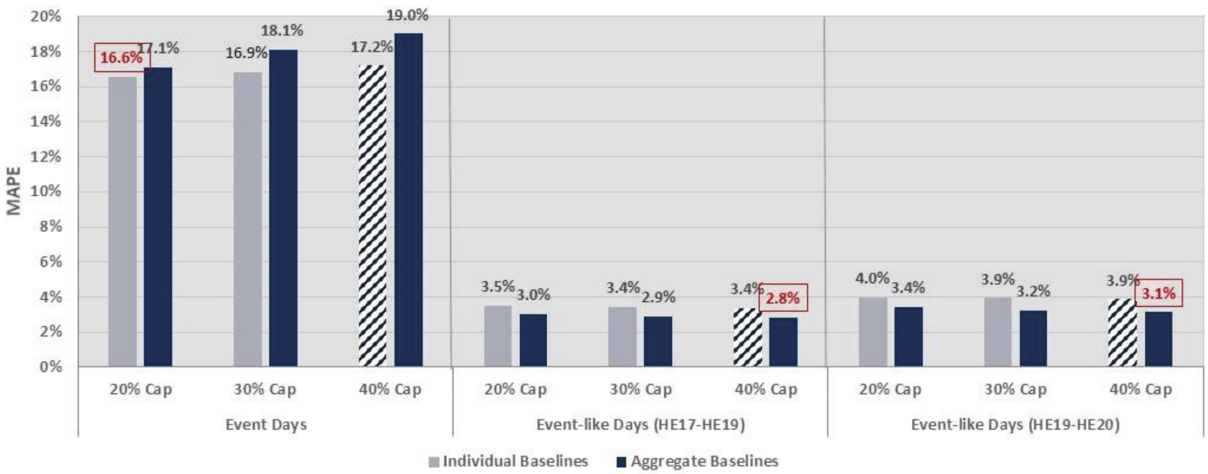
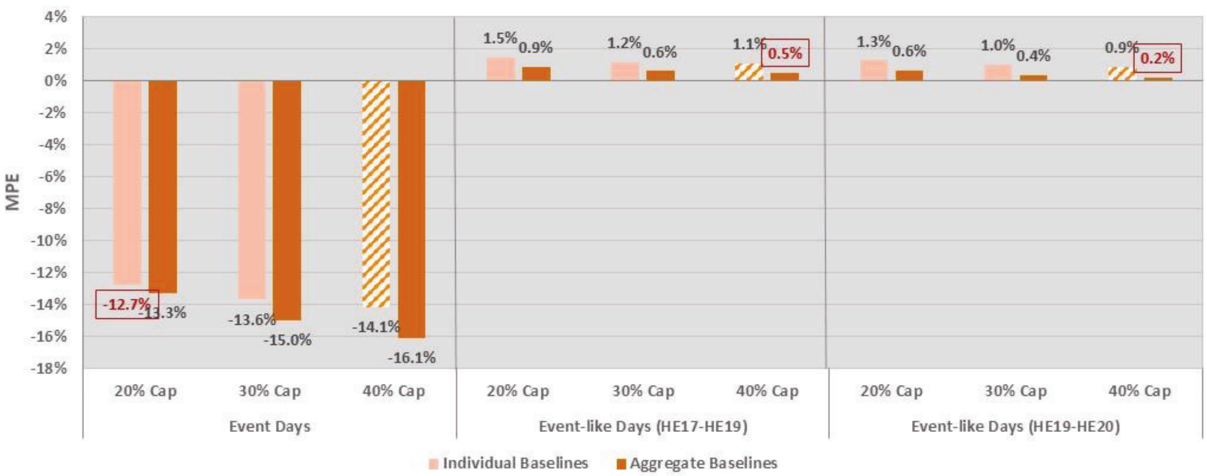


Figure A-6 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SCE DA program PY2019 results cover 21 event days and 13 event-like days and include 4 unique resources and 399 unique customers.

Figure A-7 SCE Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

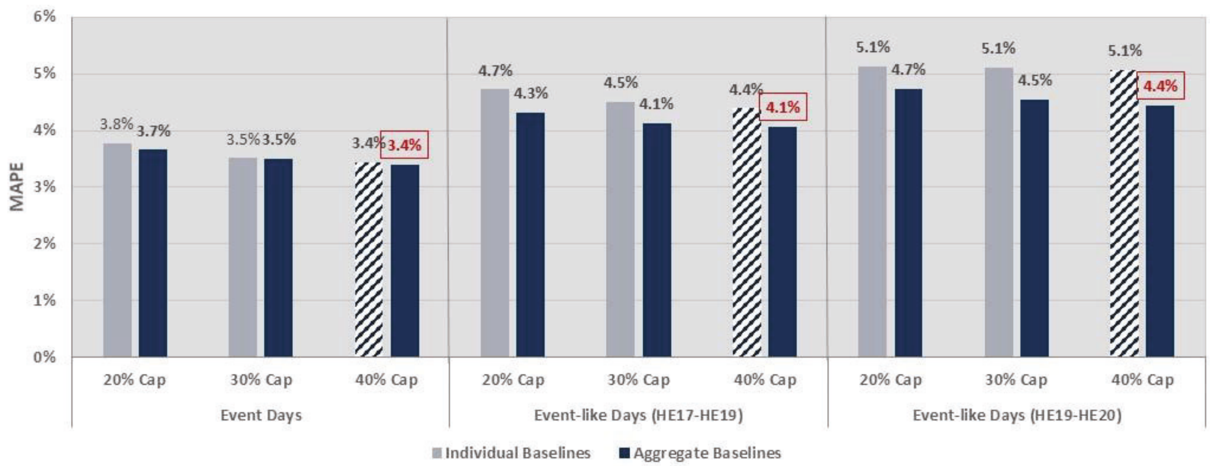
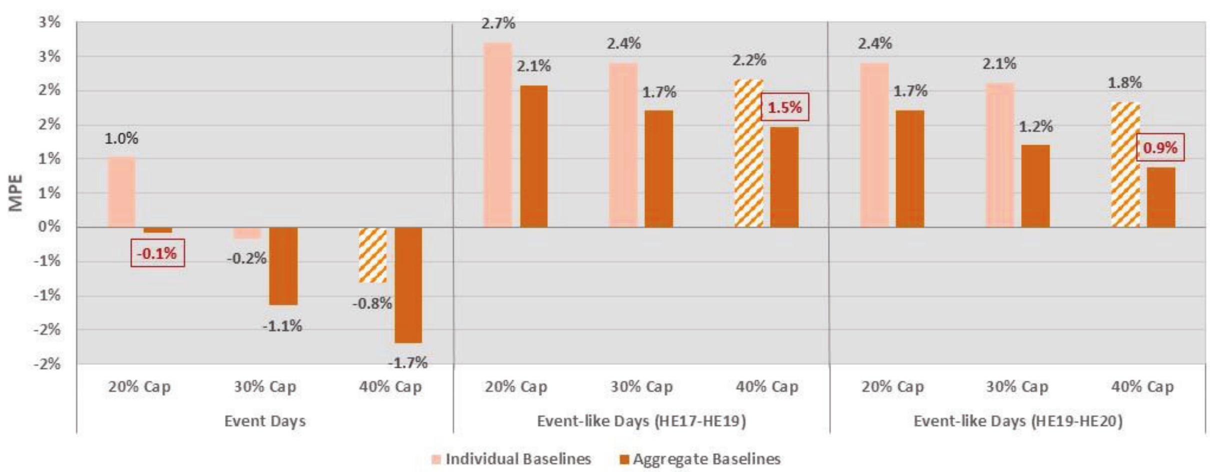


Figure A-8 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SCE DO program PY2018 results cover 25 event days and 29 event-like days and include 5 unique resources and 308 unique customers.

Figure A-9 SCE Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

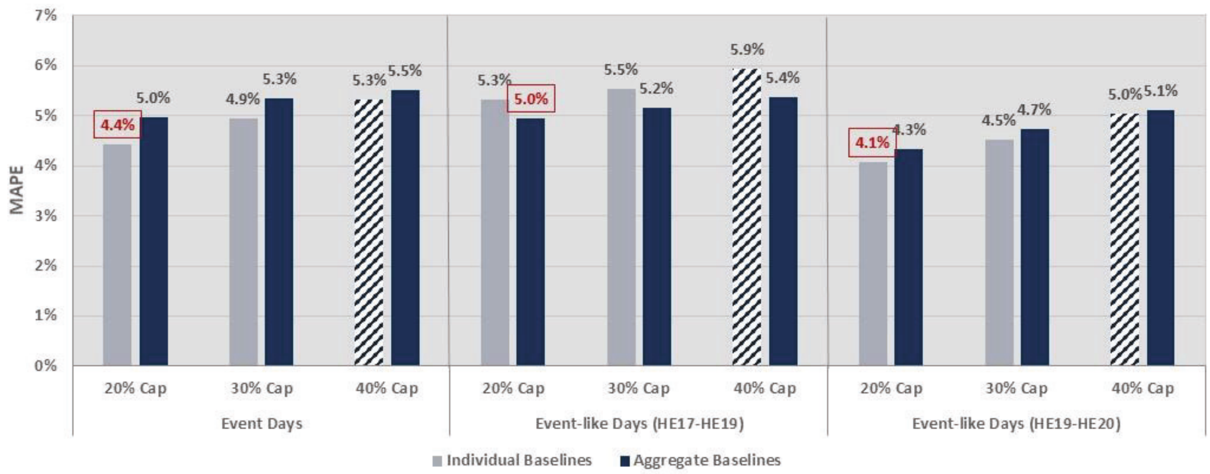
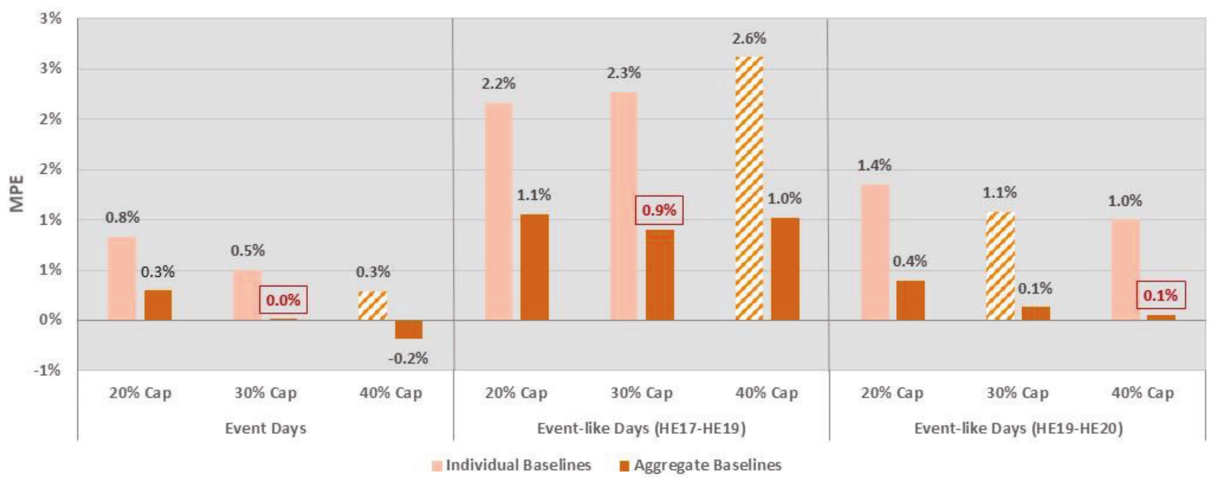


Figure A-10 SCE Day Of Program: Bias Comparison – Resource -level (PY 2018)



The SCE DO program PY2019 results cover 24 event days and 13 event-like days and include 5 unique resources and 203 unique customers.

Figure A-11 SCE Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

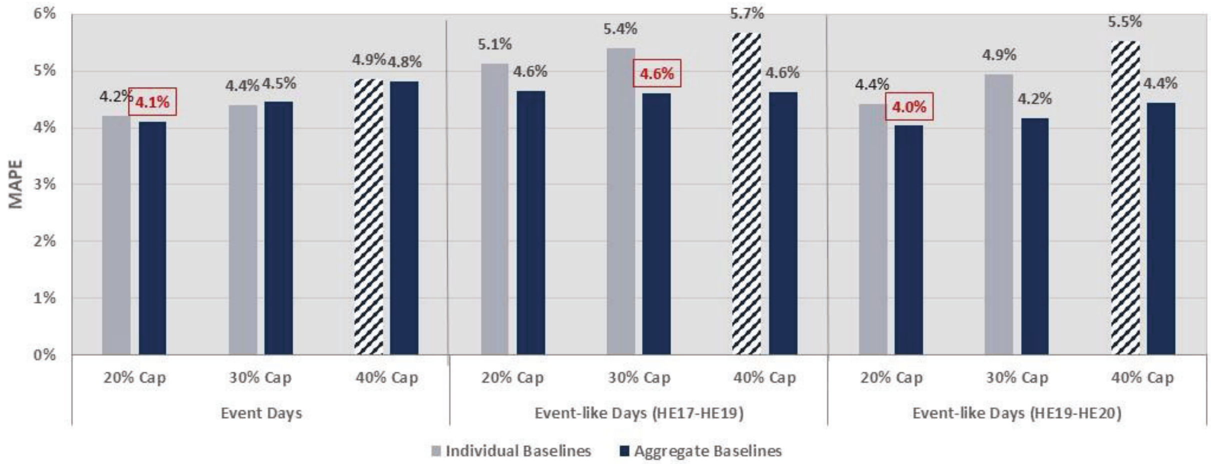
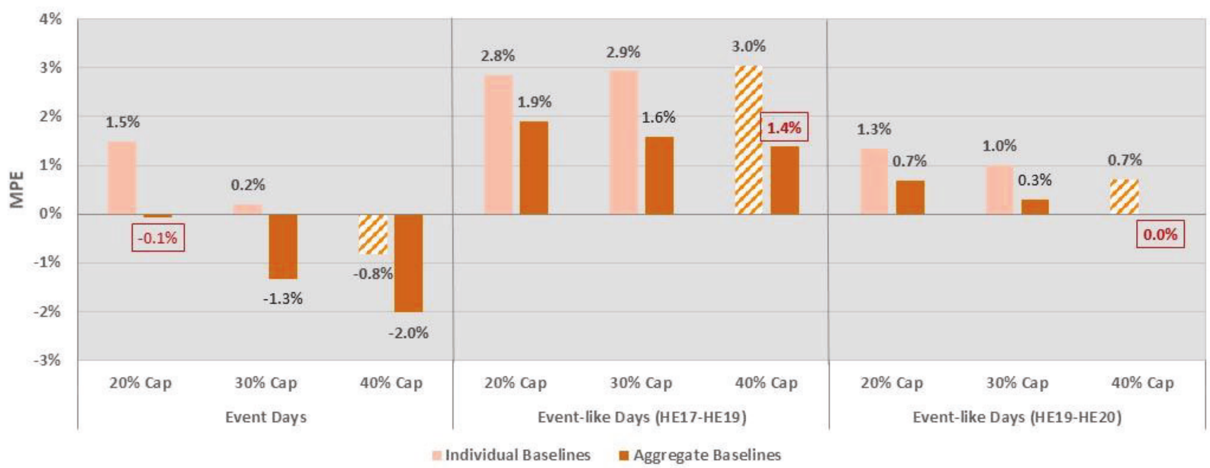


Figure A-12 SCE Day Of Program: Bias Comparison – Resource -level (PY 2019)



SDG&E Results by Program Year

Day Ahead Program

The SDG&E DA program PY2018 results cover 26 event days and 23 event-like days and include 4 unique resources and 68 unique customers.

Figure A-13 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

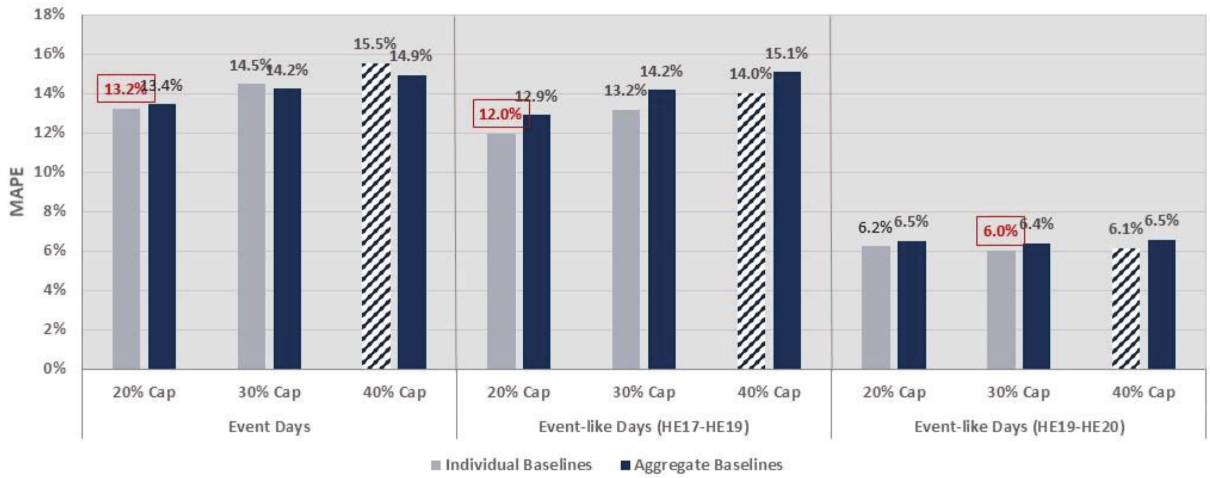
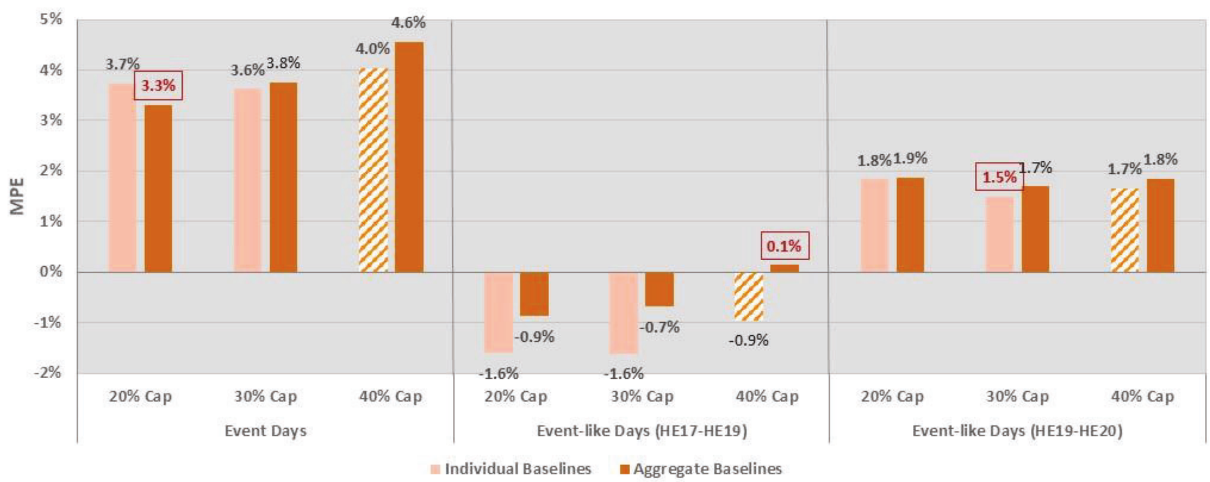


Figure A-14 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SDG&E DA program PY2019 results cover 22 event days and 13 event-like days and include 6 unique resources and 11 unique customers.

Figure A-15 SDG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

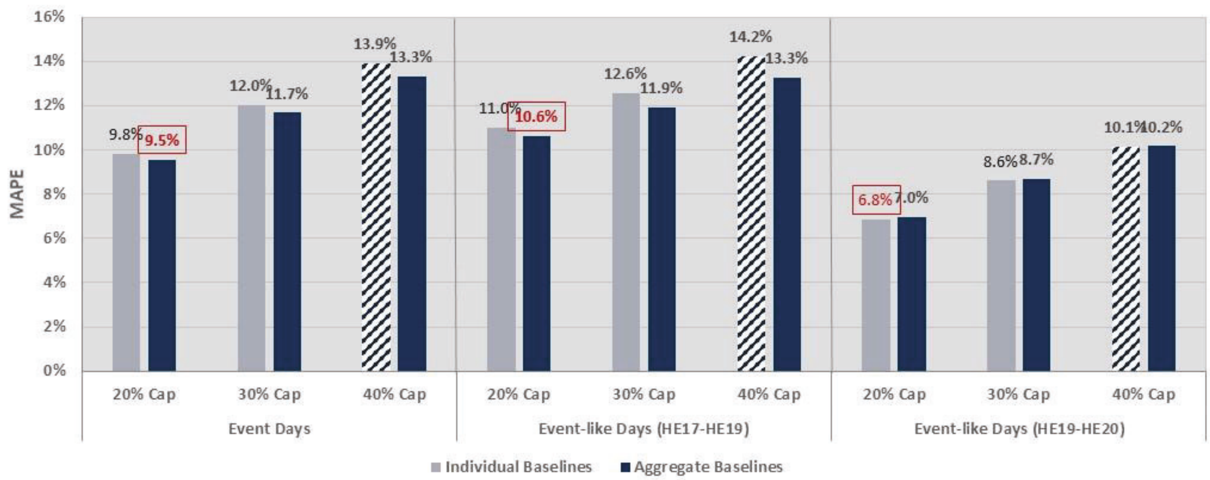
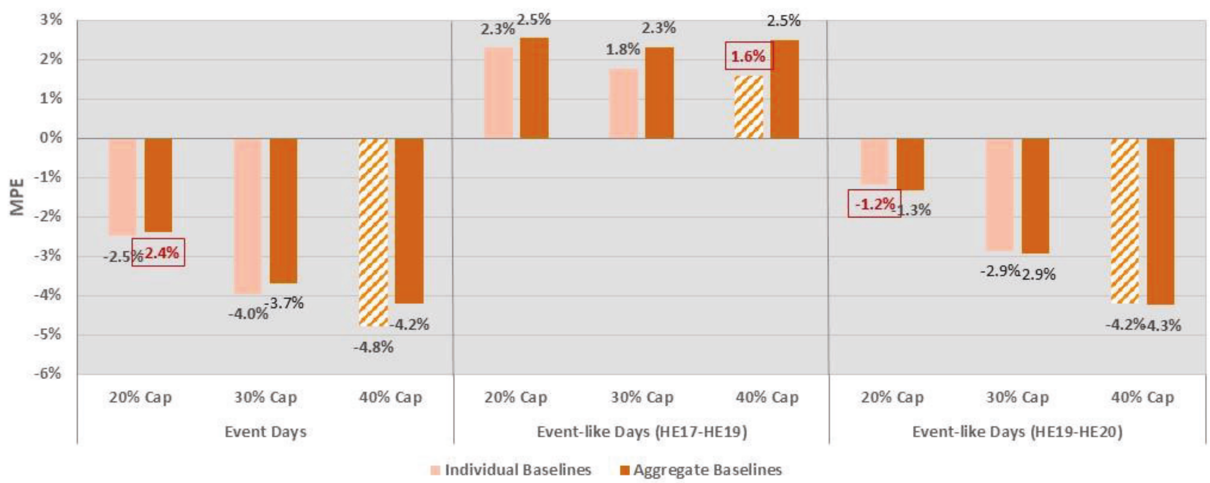


Figure A-16 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SDG&E DO program PY2018 results cover 3 event days and 23 event-like days and include 5 unique resources and 186 unique customers.

Figure A-17 SDG&E Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

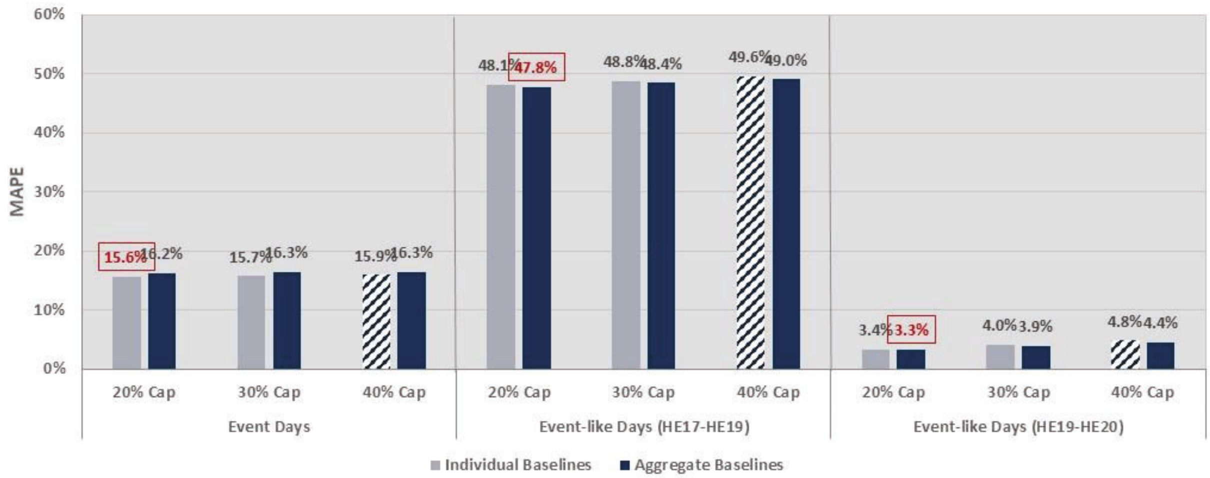
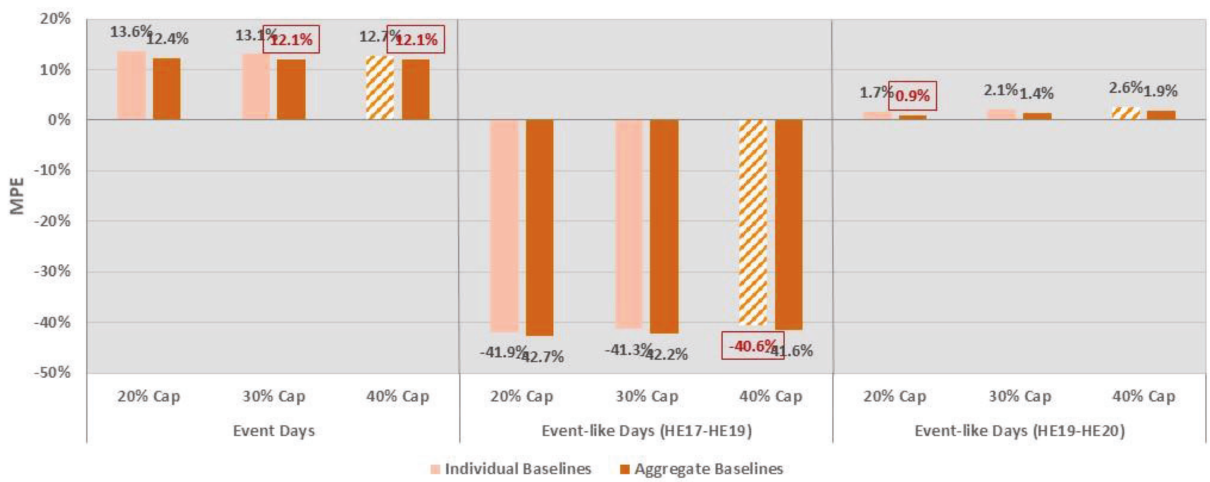


Figure A-18 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2018)



The SDG&E DO program PY2019 results cover 16 event days and 13 event-like days and include 6 unique resources and 193 unique customers.

Figure A-19 SDG&E Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

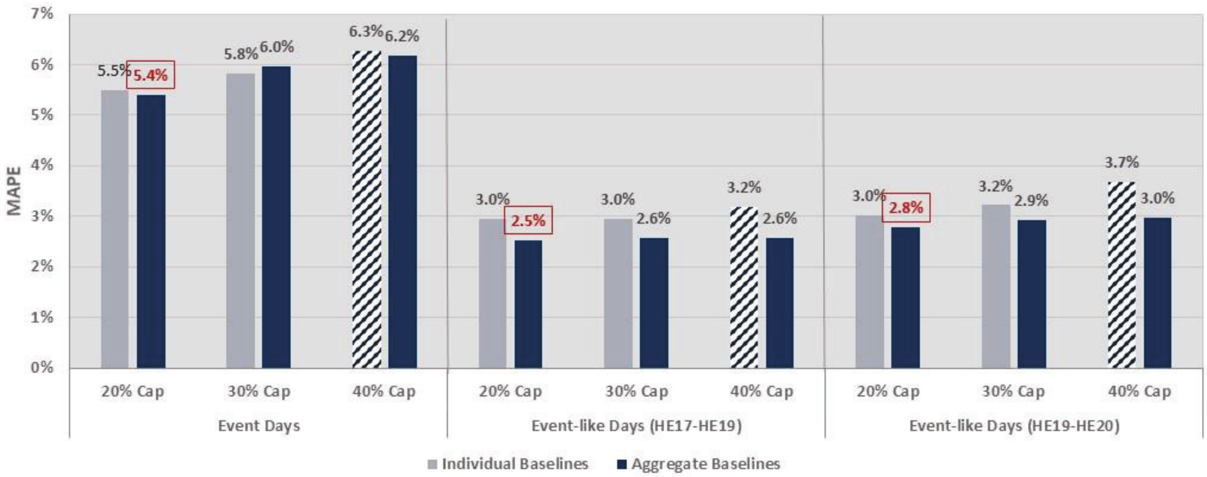
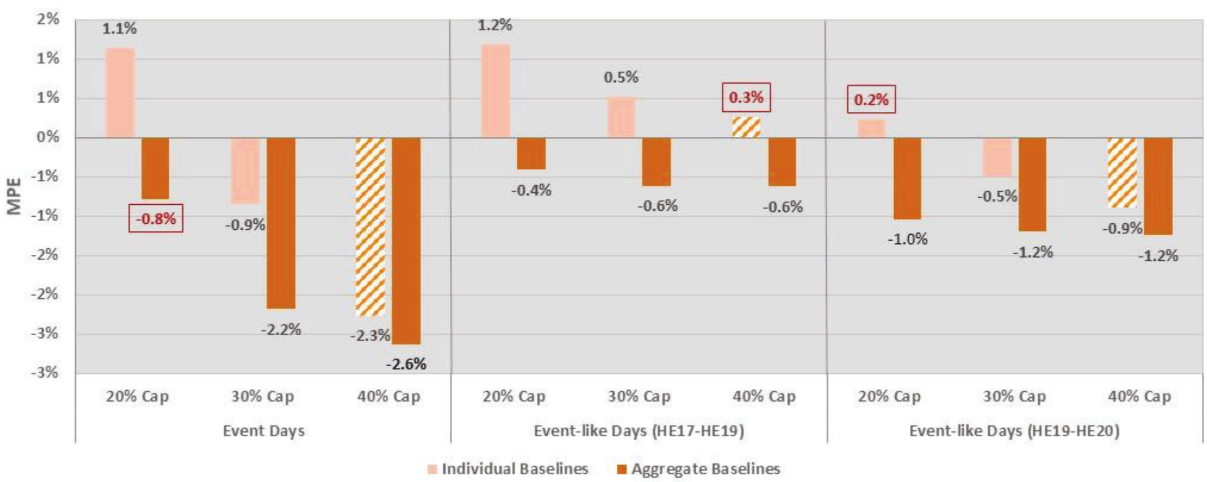


Figure A-20 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2019)



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Appendix B:
Applied Energy Group's Baseline Analysis Final Presentation

AEG Applied Energy Group

CAPACITY BIDDING PROGRAM: BASELINE COMPARATIVE ANALYSIS

Abigail Nguyen, Project Manager

Energy solutions. Delivered.

AGENDA

Analysis Objectives

Comparative Analysis

Results by Program

Key Findings & Recommendations

(PG&E-2)

2-AtchA-53

Applied Energy Group

Analysis Objectives

ANALYSIS OBJECTIVES

Applied Energy Group

D. 19-07-009 Issues to Investigate

1. Assess if an adjustment cap of ±40% is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is ±20%.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned or if they can be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

Issues Addressed by this Analysis

Directly addresses #1 and #5 by performing comparative analysis

10/10 DAY MATCHING BASELINE

AEG Applied Energy Group

Identify 10 eligible Baseline Days

Excluding weekends, other event days, ISO holidays, award dates, outages, etc.

Unadjusted Baseline
average hourly customer loads across 10 baseline days

Same-day Adjustment Ratio
Event day : Unadjusted baseline
using total kWh during adjustment period

Adjustment period: 3 hours prior to event with 1 hour buffer.

*Calculated at **<u>Aggregate or Individual</u>** level, depending on preferred baseline.*

Apply **Adjustment Cap**
Adj Ratio = (1+**X**) if Adj Ratio > (1+**X**) or
Adj Ratio = (1-**X**) if Adj Ratio < (1-**X**)

*Where X is **<u>20%, 30%, or 40%</u>**, depending on preferred baseline*

Adjusted Baseline
apply same-day adjustment ratio to each event hour in unadjusted baseline

Actual Load Reduction
= (Adj Baseline – Actual Usage) for each event hour

This step was not performed as part of this comparative analysis

Comparative Analysis

AEG
Applied Energy Group

AEG Applied Energy Group

OVERVIEW OF COMPARATIVE ANALYSIS

1

Establish scenarios for comparison: identify event days, select event-like days

2

At customer level, **calculate adjusted baseline estimates** for event days and event-like days using *six baselines*

3

Sum by resource and **calculate metrics**: accuracy (MAPE) and bias (MPE)

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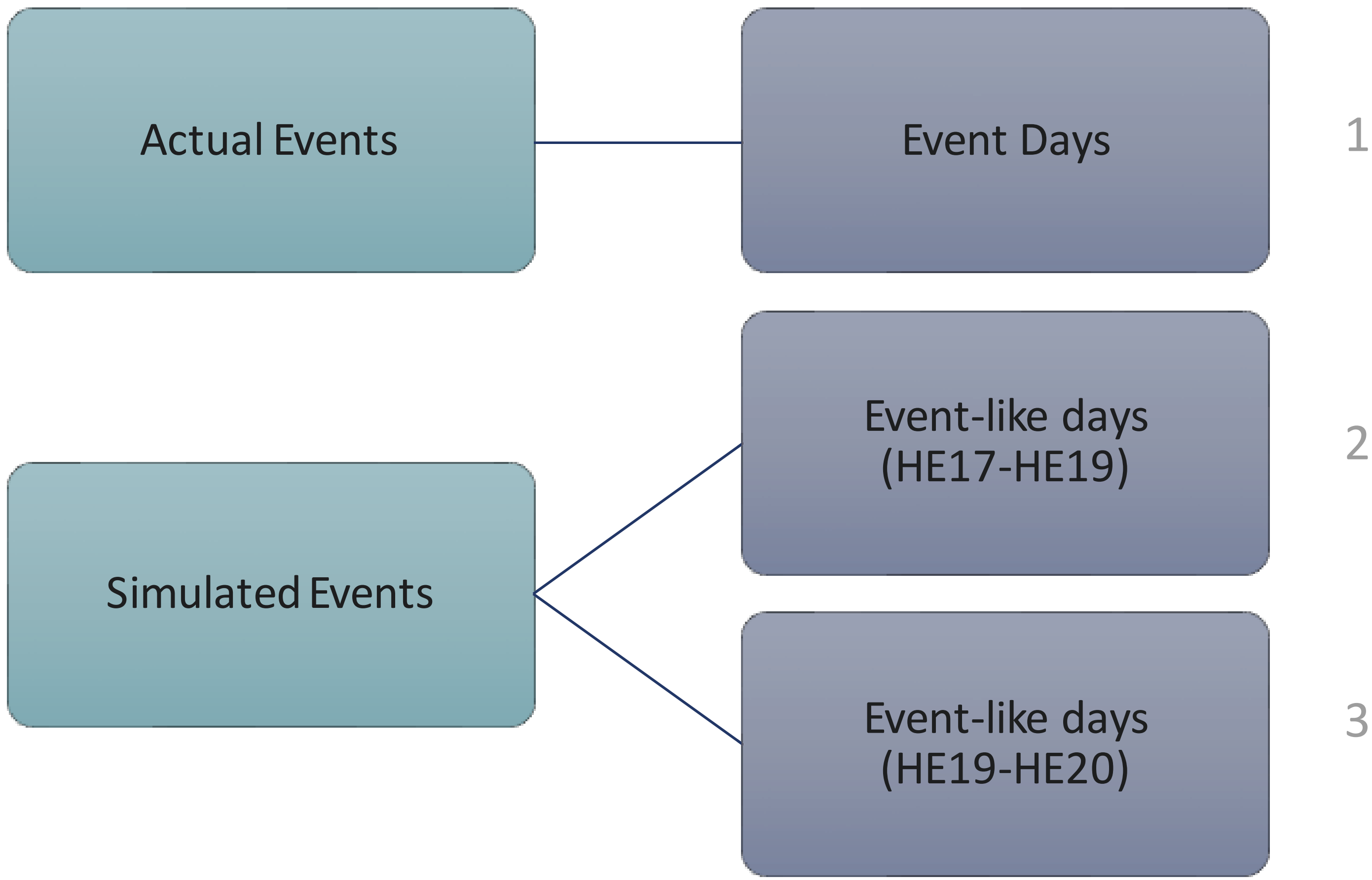
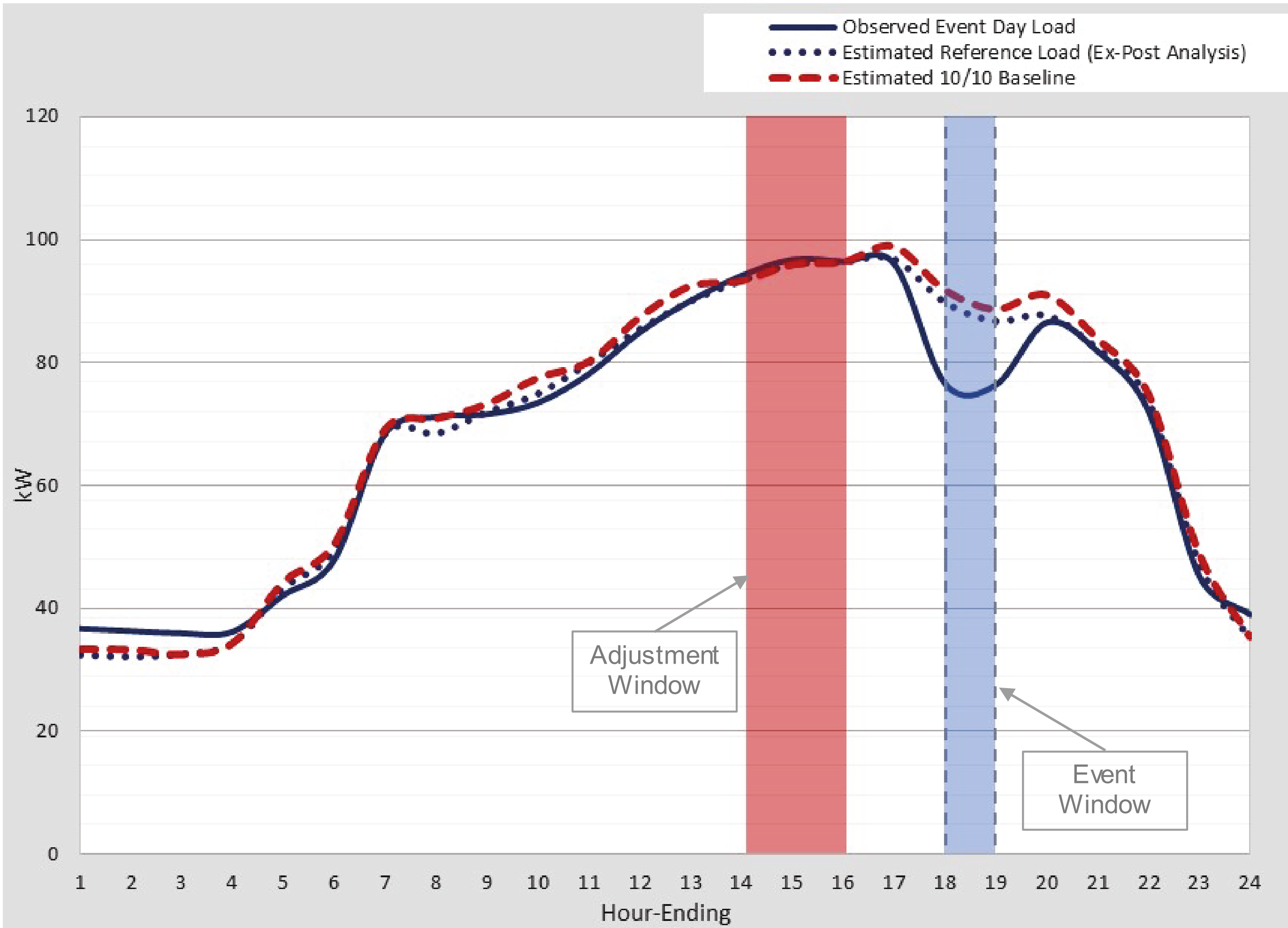
ESTABLISH THREE SCENARIOS
PY2018 and PY2019



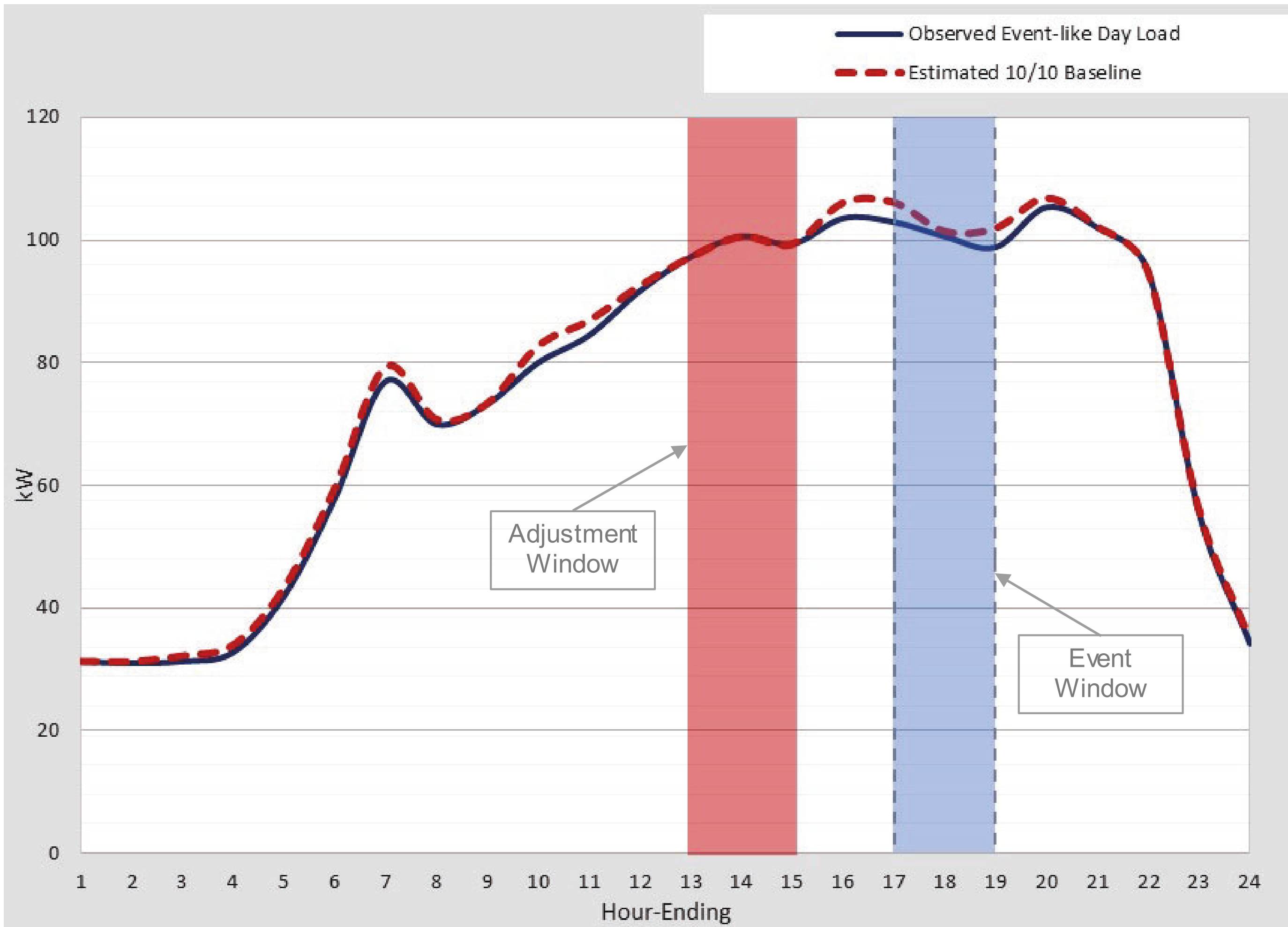
EVENT DAY SCENARIO

Applied Energy Group



EVENT-LIKE DAY SCENARIO

HE17-HE19



SIX BASELINES

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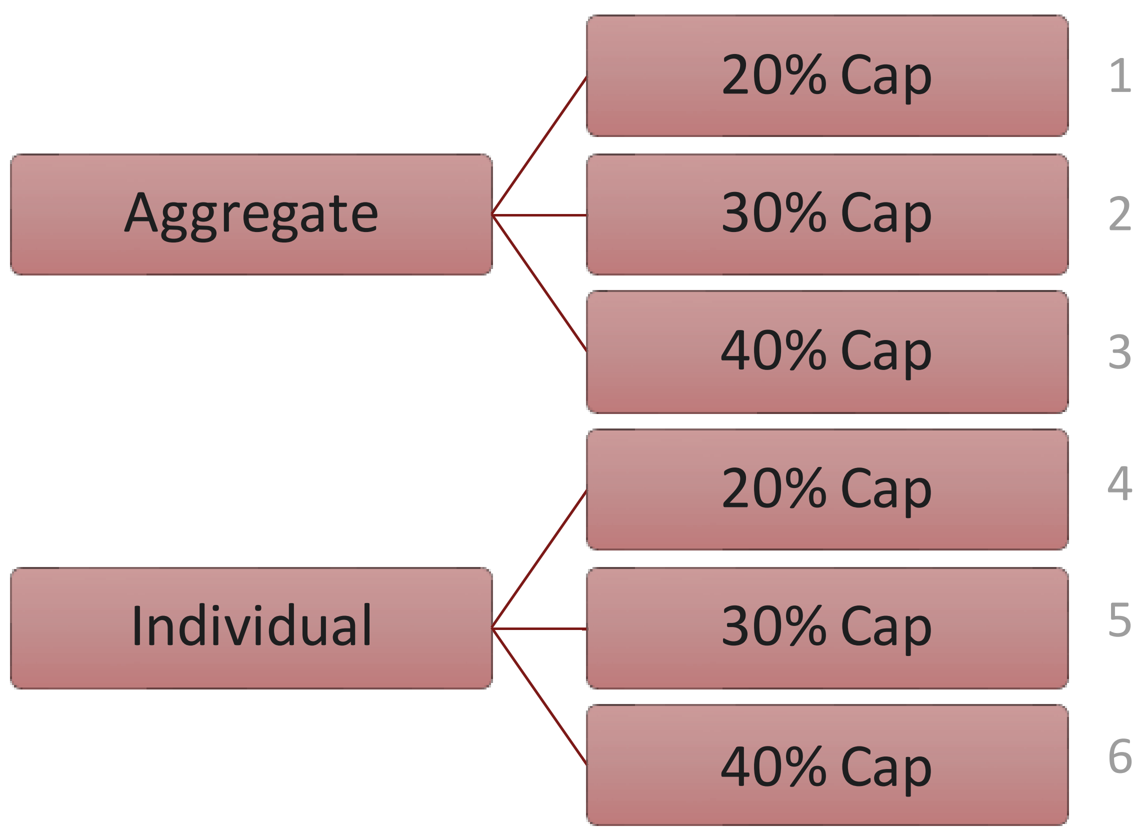


COMPARISON METRICS

ACCURACY

- Mean Absolute Percent Error

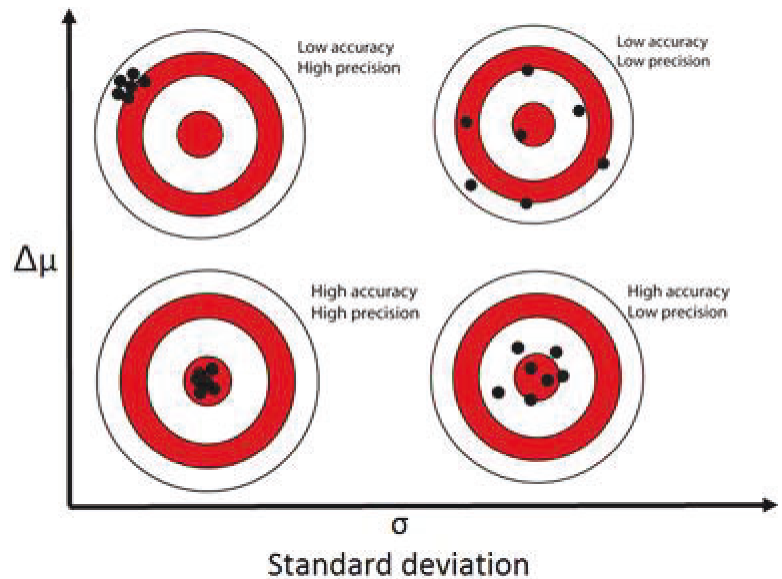
$$MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right|$$

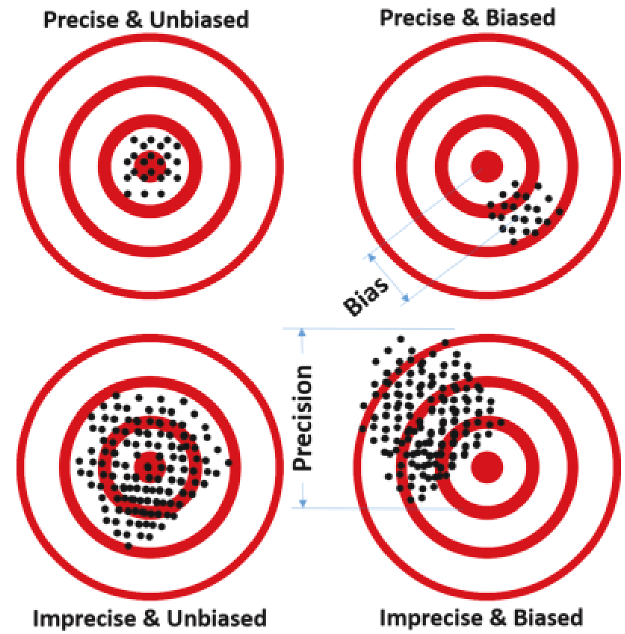
BIAS

- Mean Percent Error

$$MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h}$$

ACCURACY, PRECISION, BIAS





Accuracy - how close the estimate is to the known value

Precision - how close the two or more estimates are to each other

Bias - if estimates tend to be higher or lower than the known value

(PG&E-2)

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EXAMPLE CALCULATION

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Individual Baseline

					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

Aggregate Baseline

					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- This is a simple example showing an individual baseline versus an aggregate baseline using the same adjustment cap.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text).
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.
- The APE and PE are calculated for each resource and event day.
- The Method Score is the MAPE and MPE for each IOU and program. The simple example assumes that these four observations make up one program.

KEY POINTS ON METRIC DEVT & OVERALL ANALYSIS APPROACH

Retail settlement payments for each event day are made at the aggregator level.

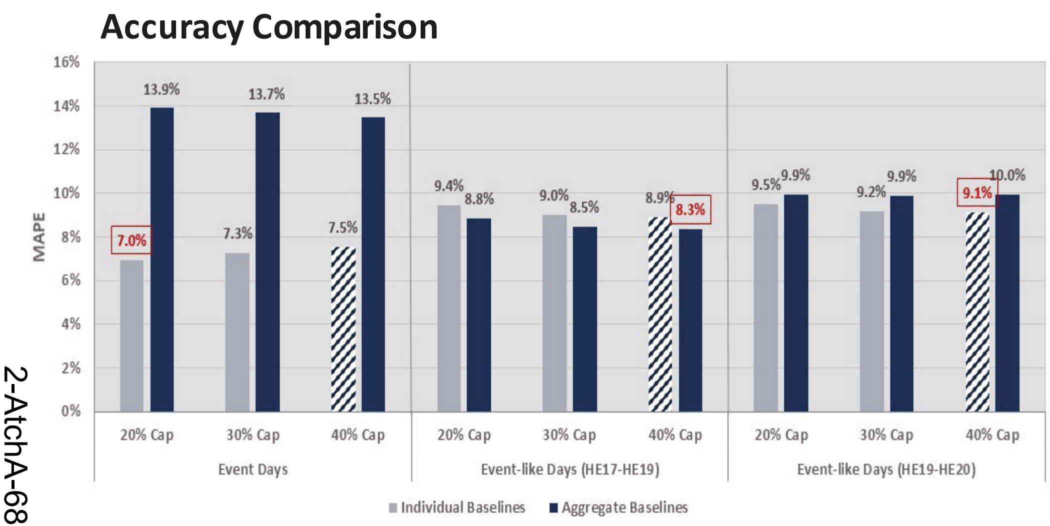
Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

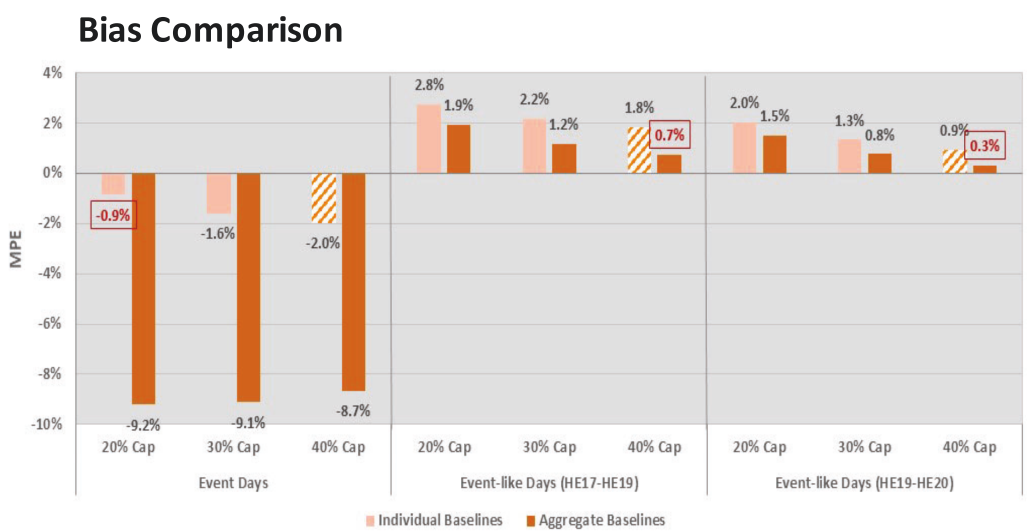
A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

Results by Program

PG&E DAY AHEAD

PY2018 & PY2019





2-AtchA-68

- Covers 55 events & 29 event-like days; 12 resources; 948 customers.
- Event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20).
- Event days and event-like days with HE19-20 simulation show similar results (better accuracy using individual baselines) – this is because PG&E DA called 30 events that start on HE19. Both scenarios use the same adjustment windows.

(PG&E-2)

SCE PROGRAMS

Applied Energy Group

Day Of

- Like PG&E DA, shows consistent results between PY2018 and PY2019.
- However, results are not consistent with PG&E—top baselines are not the same.

2-AtchA-69

Day Ahead

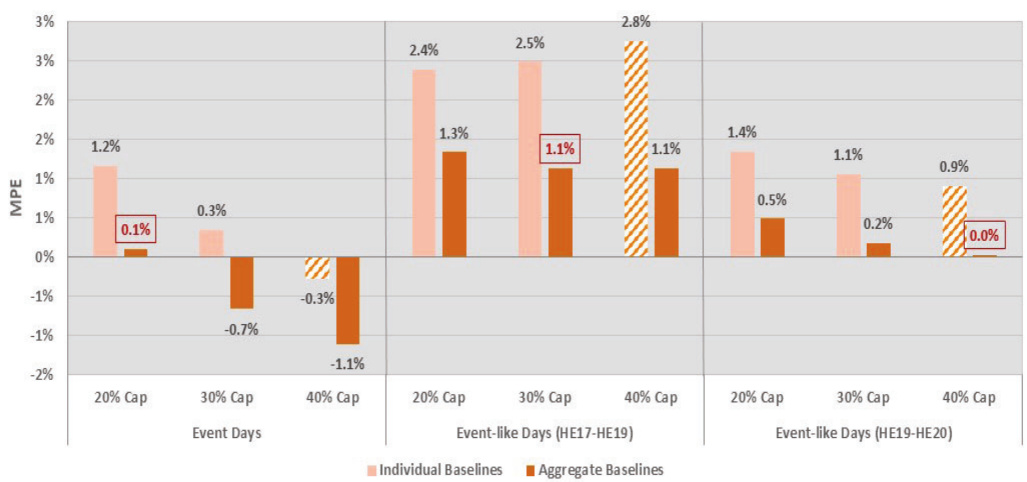
- Year-to-year results demonstrate how baseline effectiveness can be driven by the participant population.

(PG&E-2)

SCE DAY OF
PY2018 & PY2019

Accuracy Comparison

Bias Comparison



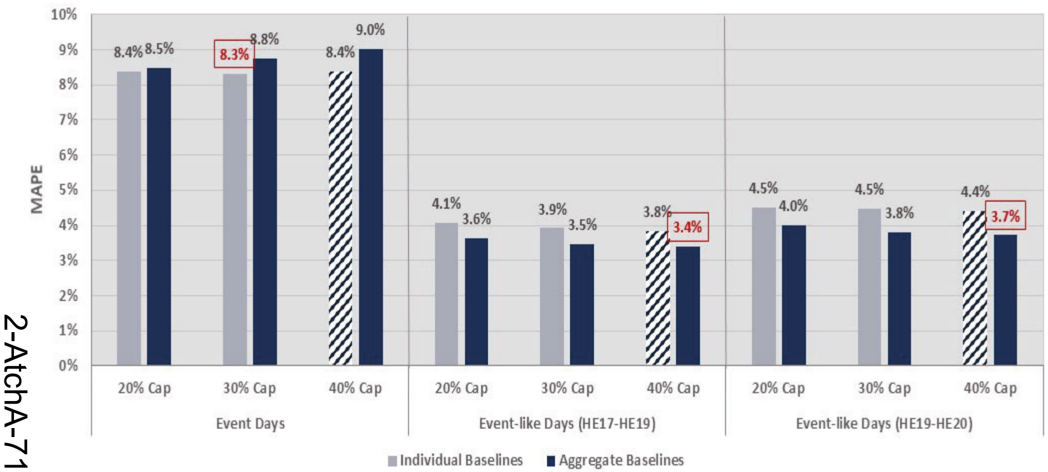
2-AtchA-70

- Covers 49 events & 42 event-like days; 6 resources; 368 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Like PG&E DA, event days and event-like days with HE19-20 simulation show similar results (best accuracy using individual with 20%) – this is because SCE DO called 38 events that start on HE19.

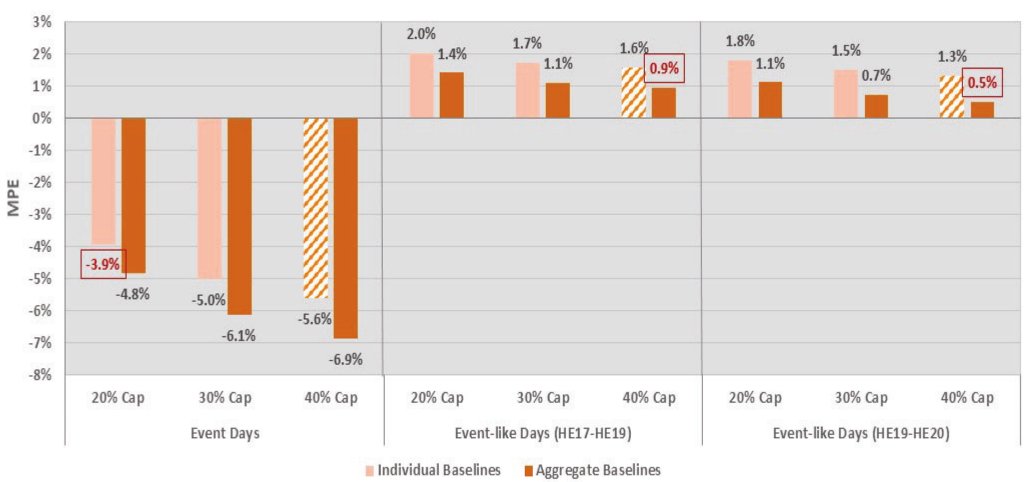
(PG&E-2)

SCE DAY AHEAD
PY2018 & PY2019

Accuracy Comparison



Bias Comparison

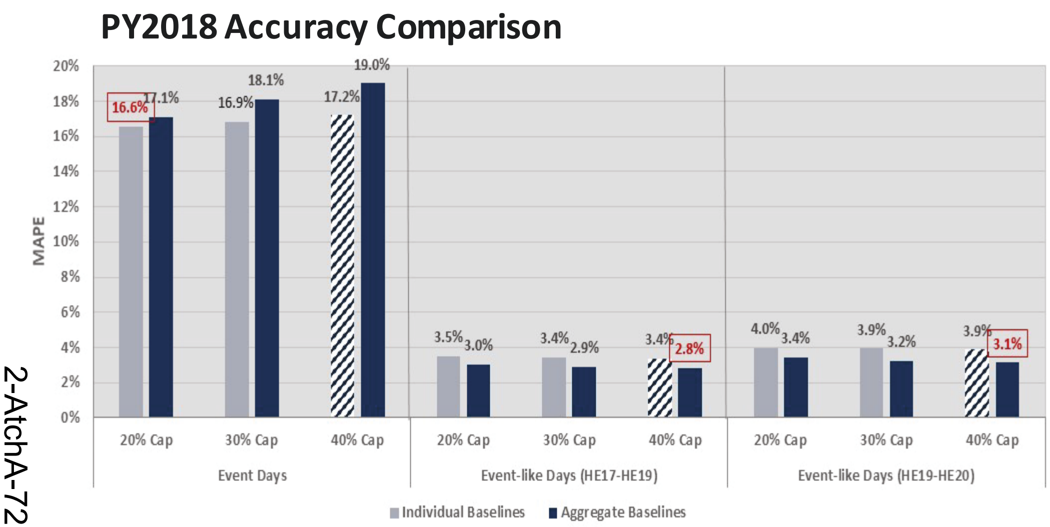


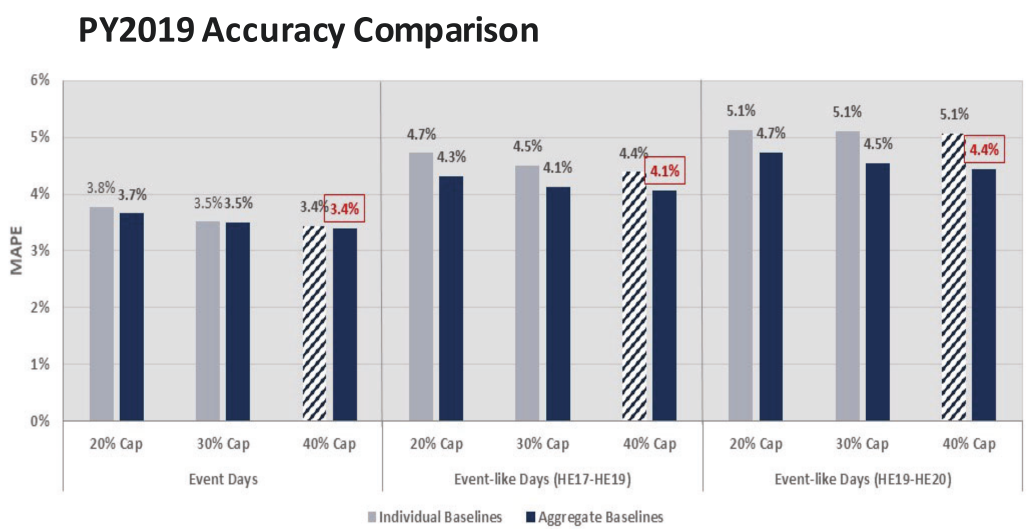
2-AtchA-71

- Covers 44 events & 42 event-like days; 5 resources; 385 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Event days show conflicting results, mainly driven by PY2018 event day data.

(PG&E-2)

SCE DAY AHEAD
PY2018 versus PY2019





- PY2018 shows event days with very low accuracy and conflicting results (best accuracy using Individual with 20% cap).
- PY2019 shows all three scenarios with very consistent results.

2-AtchA-72

(PG&E-2)

SDG&E PROGRAMS

Applied Energy Group

Day Ahead

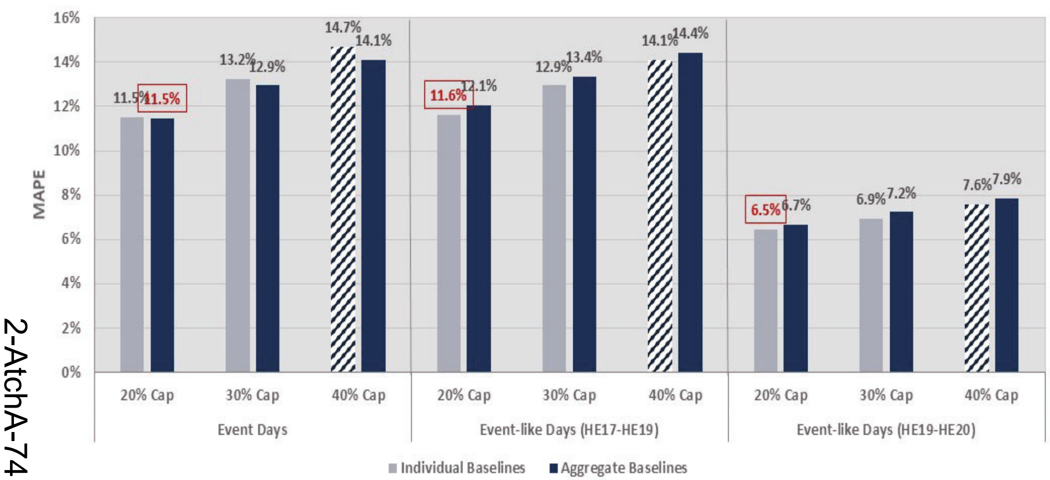
- Another example of year-to-year results demonstrating how baseline effectiveness can be driven by the participant population.

Day Of

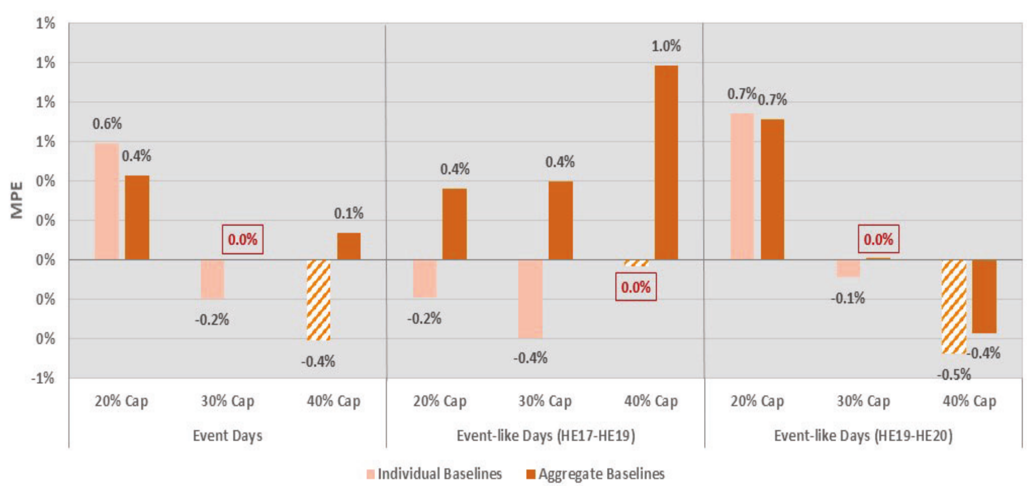
- Year-to-year results demonstrate how sensitivity to the timing of the event can be driven by the participant population.

SDG&E DAY AHEAD
PY2018 & PY2019

Accuracy Comparison



Bias Comparison



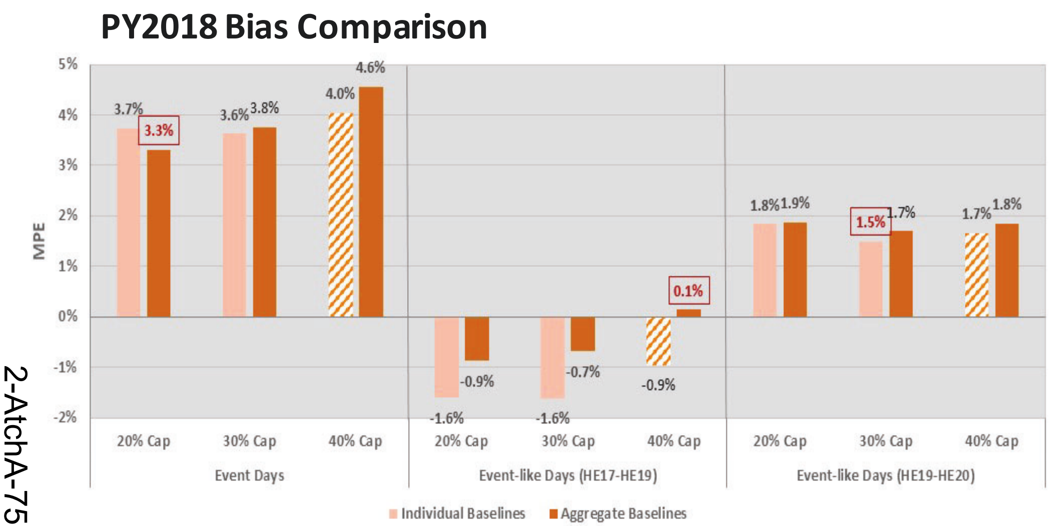
- Covers 48 events & 36 event-like days; 7 resources; 75 customers.
- Consistent accuracy results, but conflicting bias results – largely driven by the differences in participant populations between PY2018 and PY2019.

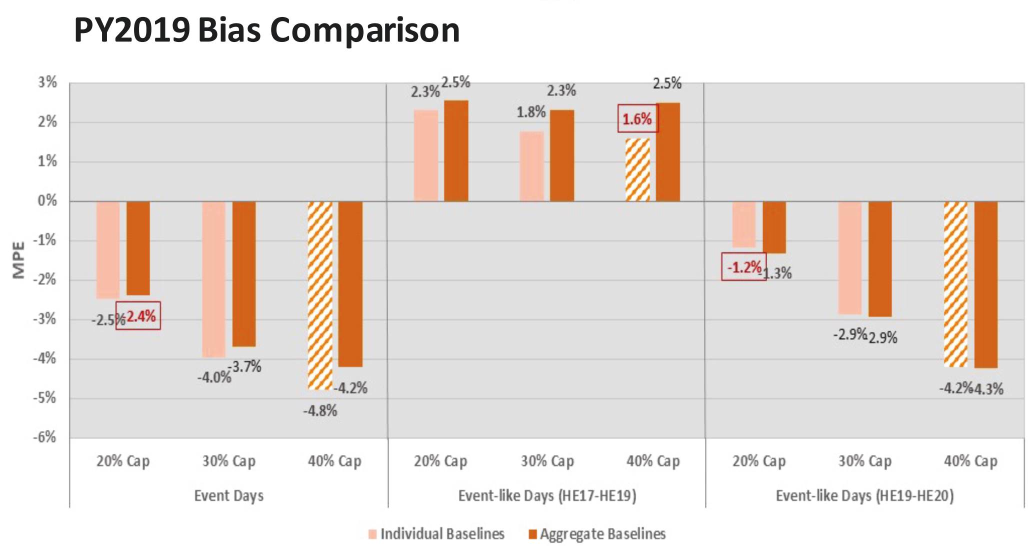
2-AtchA-74

(PG&E-2)

SDG&E DAY AHEAD

PY2018 versus PY2019



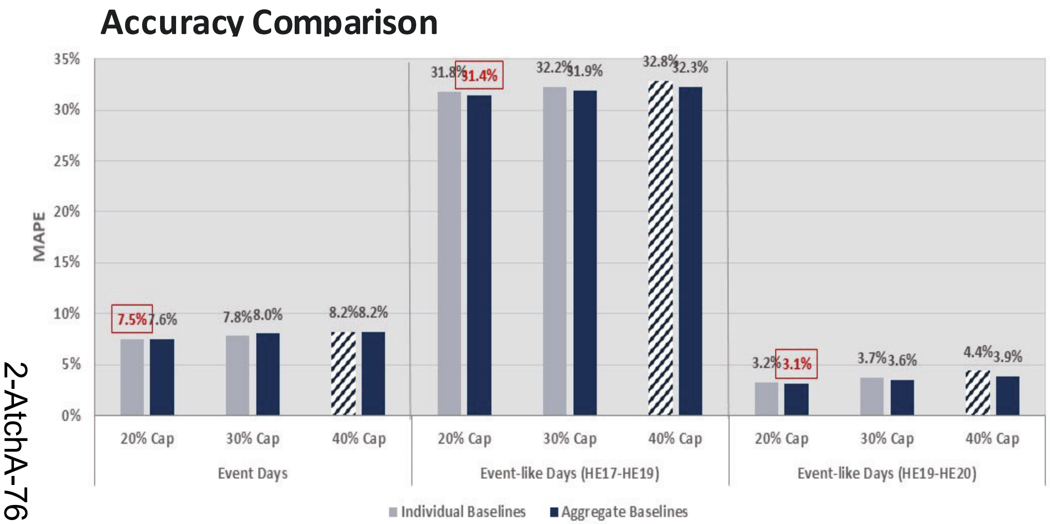


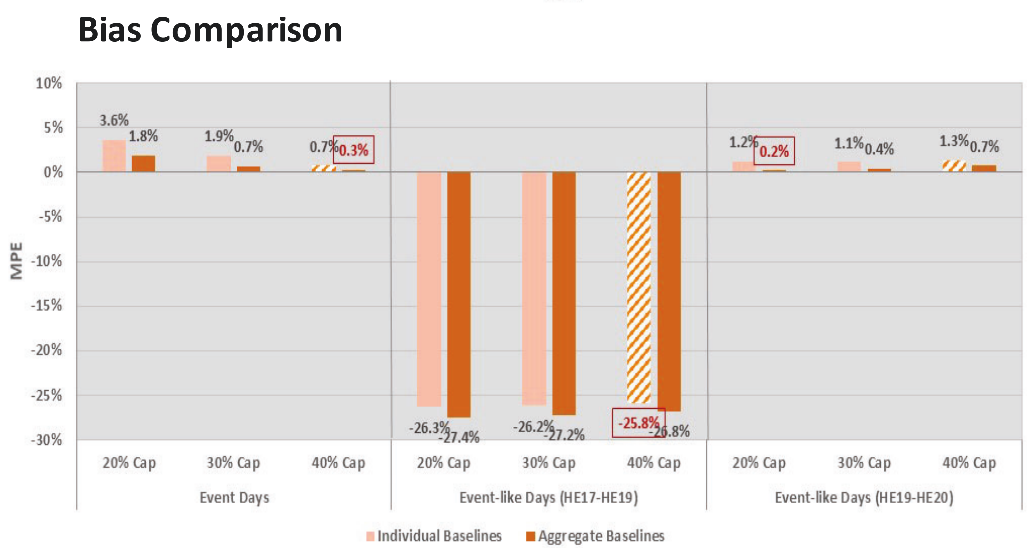
- PY2018 and PY2019 results show how directional bias and magnitude can be driven by the participant population.
- These two participant populations also show bias sensitivity to event window placement.

2-AtchA-75

(PG&E-2)

SDG&E DAY OF
PY2018 & PY2019





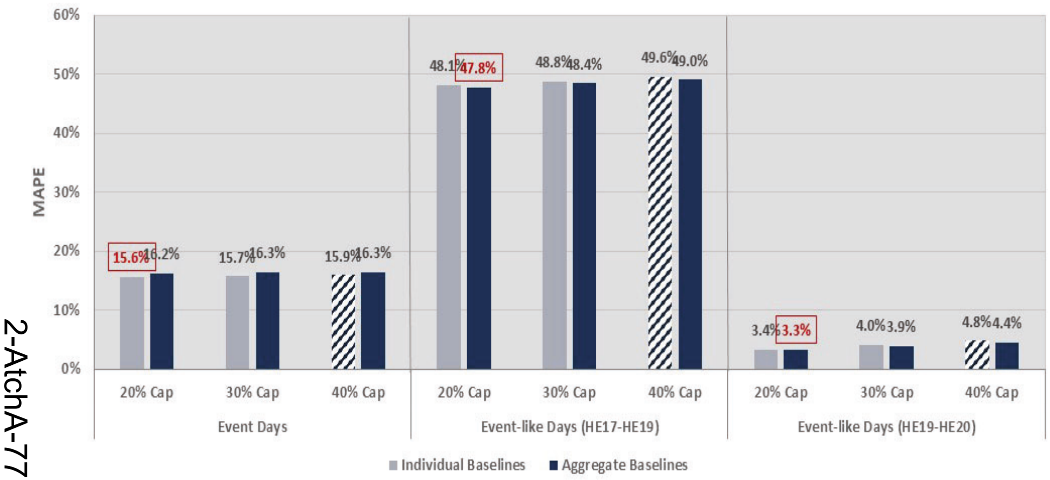
- Covers 19 events & 36 event-like days; 7 resources; 201 customers.
- Event-like day scenarios show conflicting results, indicating that baselines have high sensitivity to the timing of the event, but this also is driven by conflicting PY2018 and PY2019 results.

(PG&E-2)

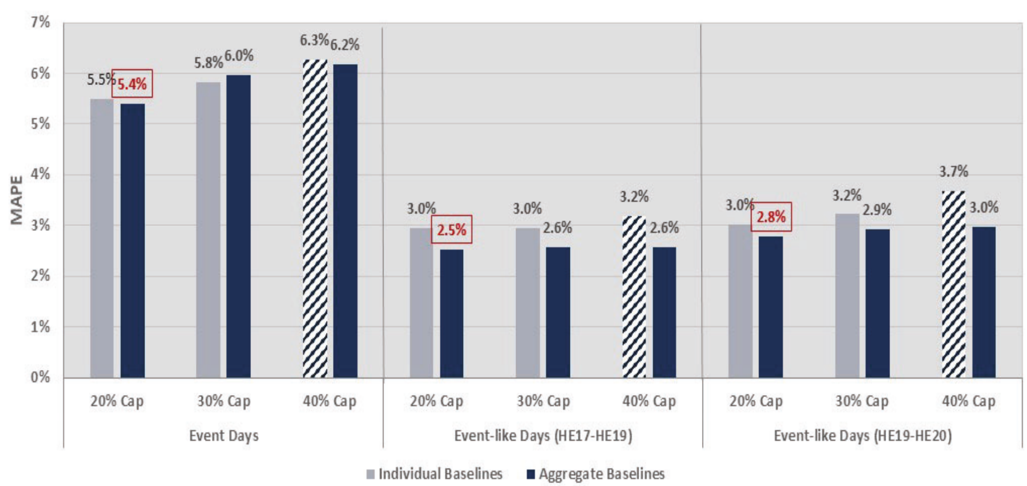
2-AtchA-76

SDG&E DAY OF
PY2018 versus PY2019

PY2018 Accuracy Comparison



PY2019 Accuracy Comparison



- PY2018 shows event-like days with very high sensitivity to the timing of the event.
- PY2019 shows all three scenarios with very consistent results.

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(PG&E-2)

Key Findings and Recommendations

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BEST ACCURACY & LEAST BIAS

Scenario	Best Accuracy: Overall	Best Accuracy: Ind v. Agg	Best Accuracy: Adj Cap	Least Bias: Overall	Least Bias: Ind v. Agg	Least Bias: Adj Cap
All Event-like days	Agg 20% (3)	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	Agg (3.5)	30% (2.2)

Score in parenthesis indicates a ranking out of 5, where 5 is the highest possible score and 1 is the lowest score.

5 = all five programs favored the same baseline
1 = each of the five programs favored different baselines

- **BIAS** – Aggregate baselines consistently give the least bias; 30% adjustment cap shows the least bias in 2.2 out of 5 programs, considering all scenarios.
- **ACCURACY** – event-like days scenarios show better accuracy using aggregate baselines, while event day scenarios show better accuracy using individual baselines. All show better accuracy using the 20% adjustment cap.

AVG DECREASE IN EFFECTIVENESS

Aggregate Baselines

	Lost Accuracy			Increased Bias		
Scenario	**Agg 20%**	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
All Event-like days	0.26%	0.49%	0.76%	0.68%	0.33%	0.28%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

Shows the average loss in accuracy and increase in bias when selecting an aggregate baseline in lieu of the top effective baseline for each program and scenario.

- Decreases in effectiveness are all under 2.3%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.
- Event day scenarios (which shows better accuracy using individual baselines) show relatively small "losses" in accuracy, showing 1% to 2.5% decreases in accuracy.

RECALL KEY POINTS ON ANALYSIS APPROACH

Retail settlement payments for each event day are made at the aggregator level.

Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

RECOMMENDATION

AEG recommends selecting the
Aggregate Baseline with 20% Adjustment cap.

Rationale

- Aggregate baseline is most effective overall, across all scenarios.
- Aggregate baseline is the most appropriate to tariff and program implementation
- Using the 20% cap aligns the retail and wholesale baseline settlements.

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RECOMMENDATION

Individual v. Aggregate Baselines?

AEG recommends using the **Aggregate Baseline**.

	Pros	Cons
Individual Baselines	• Provides more accurate estimates for individual customers.	• Provides less accurate estimates at the resource level. • Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	• Provides more accurate estimates at the resource level. • Aligns with the wholesale settlement baseline.	• Provides less accurate estimates for individual customers.

RECOMMENDATION

Which Adjustment Cap?

20% Cap	• best accuracy
30% Cap	• least bias

AEG recommends using the **20% Adjustment Cap**.

- Both accuracy and bias are not highly sensitive to the adjustment cap – differences in effectiveness, on average, is so small between the three adjustment caps.
- Wholesale settlement already uses the 20% cap – the advantages of aligning the two settlement baselines outweigh the small decrease in effectiveness.

2-AtchA-84

(PG&E-2)

AEG
Applied Energy Group

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

2024-2027 DEMAND RESPONSE PROGRAMS PROPOSALS

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
2024-2027 DEMAND RESPONSE PROGRAMS PROPOSALS

A. Introduction

This chapter explains Pacific Gas and Electric Company's (PG&E) existing and proposed Demand Response (DR) Programs for the 2024-2027 Program Cycle.[1] PG&E proposes improvements to its DR portfolio according to the vision and principles discussed in Exhibit (PG&E-2), Chapter 1. These proposals build upon improvements approved in Decision (D.) 21-03-056 and D.21-12-015 as part of the Emergency Reliability Order Instituting Rulemaking (OIR).[2] In cases where PG&E's program enhancement proposals are not deemed cost-effective, PG&E also summarizes alternative and cost-effective program proposals. In addition to the specific program enhancement proposals described below, as described in Exhibit (PG&E-2), Chapter 2, PG&E seeks procedural changes that provide greater flexibility to adjust program design and incentives over the course of the funding cycle to address emerging grid and/or customer issues.[3]

The outline of this chapter and summaries of PG&E's recommendations may be found in Table 3-1 below.

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1 PG&E proposes program changes and funding for 2023 in Exhibit (PG&E-1), Chapter 1 of this application.

2 Rulemaking (R.) 20-11-003, OIR to Establish Policies, Processes and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021 (R.20-11-003, Emergency Reliability OIR) (Nov. 20, 2020).

3 PG&E views flexibility both in terms of the process and expediency for approval of programmatic/pilot modifications, as well as budgetary accommodations for fund shifting.

TABLE 3-1
SUMMARY OF PROGRAM PROPOSALS

Line No.	Section	Program	Proposal	Customer/Grid Benefit
1	B.2.a	Base Interruptible Program (BIP)	Enrollment Processes	PG&E proposes permanently replacing the annual lottery with year-round enrollment for new or increased participation. PG&E also proposes that new customers must remain in BIP for at least six months before unenrolling from the program or raising the firm service level (FSL). The first proposal allows the customer more flexibility to enroll in BIP. The second proposal creates a more reasonable commitment period for BIP.
2	B.2.b	BIP	Higher Incentive Rates	PG&E proposes raising May-October incentive rates by $2/kilowatt (kW) to encourage increased BIP participation even as grid needs have evolved since 2020 to include more frequent and consecutive dispatch of emergency resources.
3	B.2.c	BIP	Changes In Event Limits	PG&E proposes that: (1) the program events are limited to 10 events during a rolling 30-day window, and (2) a 3-day limit on consecutive event days. The proposal limits disruption to customers' operations while encouraging program participation.
4	B.2.d	BIP	15-Minute Option	A 15-minute BIP option can help address emergency grid needs and local capacity requirements, as market resources that can respond in less than 20 minutes can meet local Resource Adequacy (RA) requirements.
5	B.2.e	BIP	Marketing, Education, and Outreach (ME&O)	ME&O will focus on targeted outreach efforts to raise program awareness and increase enrollment participation up to the program's reliability cap.
6	C.1.a.1	Capacity Bidding Program (CBP)	Revision To Payment/Penalty Structure	Proposed change will revise Payment Penalty structure that incentivizes participation in the program by rewarding higher levels of performance and lowering the penalty threshold, while still recouping costs for severe underperformance.

TABLE 3-1
SUMMARY OF PROGRAM PROPOSALS
(CONTINUED)

Line No.	Section	Program	Proposal	Customer/Grid Benefit
7	C.1.a.2	CBP	Removal of Underused Options	Proposed change will eliminate rarely used event hour option and will ensure clarity to dispatch events that meet grid needs.
8	C.1.a.3	CBP	Enhanced Testing Process	Proposed changes will help in prioritizing resources and efficiently identifying only those resources that need to participate in testing events, hence enhancing chances for good performance when resources are called for actual events
9	C.1.a.4	CBP	Weekend Participation	Proposed changes will make Saturday participation as mandatory to comply with RA requirements for DR as described in D.21 06 029
10	C.1.b	CBP	2023 Bridge Year Proposals	These changes have been proposed in Exhibit (PG&E-1), Chapter 1, Section C.b. of this application for 2023. However, in the event the changes do not get approved for 2023, PG&E is seeking approval to implement these changes in 2024 along with the other 2024-2027 Program changes
11	C.2	CBP	ME&O	Proposed ME&O efforts will increase awareness and reach of CBP, thereby motivating enrollments and increasing the program effectiveness
12	D.1.a	SmartAC™[(a)]	Continue the SmartAC Program with new program parameters starting in 2024	This allows for PG&E to utilize the existing installed technology with enrolled participants in a residential DR program. The restriction of further enrollments will minimize the ineffective cost spend that PG&E is undertaking for residential DR.
13	D.1.b	SmartAC Program	Close the Commercial SmartAC Tariff	PG&E requests to close the commercial SmartAC tariff which is still in effect despite new enrollments not being allowed.
14	D.1.c	SmartAC Program	ME&O	PG&E will provide limited outreach to enrolled residential SmartAC customers and cease marketing to attract new enrollments to the SmartAC Program.

TABLE 3-1
SUMMARY OF PROGRAM PROPOSALS
(CONTINUED)

Line No.	Section	Program	Proposal	Customer/Grid Benefit
15	E	Automate Response Technology (ART) Program	This new residential program would serve to enable customers to leverage multiple technologies for load management, such as DR and Time-of-Use (TOU)/Load Shifting beginning in 2024.	The enablement of multiple technologies to serve grid needs in a unified manner. ART goes beyond traditional load drop DR as it would also support Load Shifting. This Program offering is envisioned to qualify as a market integrated DR program for customers that are required to join a DR program, such as those taking an incentive rebate from Self-Generation Incentive Program (SGIP)-Heat Pump Water Heater (HPWH).
18	F.1.a	Permanent Load Shift (PLS) Thermal Energy Storage	PG&E proposes to end the requirement to submit five years of monitoring data for performance evaluation.	The proposed change will save $687,705. The potential amount recoverable from non-performing customers is less than 100 percent of the program’s incentive cap of $2.06 million. If customer PLS system performance is at 90 percent, PG&E may request customers to pay back 10 percent of the $2.06 million dollars, or $206,000. Spending $687,705 to recover $206,000 is not a good use of rate payer funds.
19	F.1.b	Optional Binding Mandatory Curtailment (OBMC)	PG&E proposes to continue the program and is not recommending any changes.	Considering increasing challenges imposed on the grid by extreme weather events and wildfires, OBMC will continue to exist to support California Independent System Operator (CAISO) stage emergencies.
20	F.1.c	Scheduled Load Reduction Program	PG&E is not proposing changes to this program.	PG&E is not proposing changes for Scheduled Load Reduction Program (SLRP), but notes that this program is enshrined in Public Utilities Code (Pub. Util. Code) Section 740.10 and cannot be closed without legislation, regardless of participation levels.

TABLE 3-1
SUMMARY OF PROGRAM PROPOSALS
(CONTINUED)

Line No.	Section	Program	Proposal	Customer/Grid Benefit
21	G.1 and G.2	ME&O for DR Portfolio	Objectives & Approach	PG&E aims to develop a framework for customer and technology segmentation, coordinate with internal relationships and external partners to increase education and outreach activities, increase customer enrollments, as well as retaining existing customer enrollments.
22	G.3	ME&O for DR Portfolio	Online Platform for Residential DR Offers	To improve the residential customer experience, PG&E is creating an online platform that will provide an overview of the DR programs that are available through PG&E

(a) The name SmartAC is a registered trademark of PG&E. All further references to the program in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

B. Base Interruptible Program

1. Event and Enrollment History

Since 2010, PG&E's BIP participants had historically been dispatched one to two times per year, primarily for local transmission emergencies impacting a small subset of BIP participants and for PG&E authorized test events. This changed in 2020 when BIP was heavily relied upon for multiple and consecutive days in 2020 to provide load reduction during systemwide grid emergencies caused by extreme heatwaves in August and September. Most BIP participants were dispatched for up to seven emergency events: five consecutive days in August and two consecutive days in September. Table 3-2 below shows the historical BIP events from 2010 to 2021.

TABLE 3-2
BIP TRANSMISSION EMERGENCIES 2010-2021

Line No.	Event Date	Trigger	# Dispatched Accounts	Program Tolled Hours
1	3/11/2011	Not specified	9	0.3
2	2/6/2014	Ordered by the CAISO	220	4.0
3	5/3/2017	CAISO Stage 1 Emergency	331	1.4
4	7/27/2018	Transmission Emergency	7	4.0
5	2/23/2019	Transmission Emergency	119	3.0
6	8/14/2020	Transmission Emergency	480	5.8
7	8/15/2020	Transmission Emergency	468	5.1
8	8/16/2020	Transmission Emergency	472	1.7
9	8/17/2020	Transmission Emergency	482	4.0
10	8/18/2020	Transmission Emergency	482	5.5
11	9/5/2020	Transmission Emergency	425	2.4
12	9/6/2020	Transmission Emergency	467	3.1
13	7/9/2021	Transmission Emergency	293	2.0

The nature of when, why, and how often BIP is dispatched has evolved since 2020 to include frequent and consecutive systemwide grid emergencies associated with California's changing climate and grid needs. Due to this, PG&E anticipates the continued and frequent use of Reliability Demand Response Resource (RDRR) to address short-term reliability issues.

Following the August and September 2020 BIP events, approximately one-third of the program's service accounts chose to unenroll from the program at the end of the calendar year, and the program lost approximately 50 megawatts (MW) between April 2020 and April 2021. As illustrated in the table below, the exodus of customers at the end of 2020 was notably higher than in previous years. Based on conversations with PG&E's third-party aggregators and customers participating in BIP, PG&E believes this is the result of customer fatigue and hardship due to the number, duration, and consecutive nature of the 2020 BIP events. Even though only one BIP event was dispatched in 2021—as illustrated in Table 3-3—the program has continued to experience attrition and low enrollment compared to historical years.

TABLE 3-3
EX ANTE: AUGUST PEAK

Line No.	Item Detail	2017	2018	2019	2020	2021	2022
1	Enrollment	330	362	421	512	308	268
2	MWs	300	221	254	236	183	170

Note: 2016-2021 Load Impact Evaluation of California Statewide BIPs for Non-Residential Customers: *Ex-post* and *Ex-ante*. Report Enrollments reflect the program count captured for the April filing of the respective year. MW estimates reflect the average of Portfolio-Adjusted hourly ex ante load impacts (MW) under utility 1-in-2 weather conditions from 4 to 9 p.m. during the August peak.

PG&E's proposals for the 2024-2027 funding cycle intend to address these changes in customer participation by ensuring customers are incentivized to participate in BIP even as capacity needs evolve. PG&E's proposals take steps to encourage new participation in the BIP Program and reduce program attrition.

Conversations with key stakeholders informed the below proposals. To better understand the customer experience—including program preferences and barriers—PG&E solicited program feedback in 2021 and 2022 from the six third-party aggregators currently participating in BIP, several direct enroll BIP participants, and one association that represents PG&E's large industrial electric customers. Additionally, PG&E account representatives were able to provide feedback on barriers to participation after conducting a month-long BIP outreach effort in 2021.

2. Program Proposal

a. Enrollment Processes

PG&E proposes to continue year-round enrollment for new or increased BIP participation through 2027, regardless of the duration of the Emergency Load Reduction Program (ELRP) pilot, which currently sunsets in 2025. Eligible customers should continue to be accepted into the program through 2027 on a first come, first served basis if there is still available headroom under PG&E's portion of the reliability cap. PG&E does not propose any changes to the unenrollment window, which occurs once annually at the end of the calendar year, and allows for both program un-enrollments and FSL increases. To ensure reliability of BIP resources, it is reasonable to limit unenrollment and increase in FSL to once per year, in November.

1) Permanently End Lottery System

PG&E proposes to permanently end the lottery system. D.18-11-029[4] cited D.17-12-003[5] when it established a lottery process for BIP applicants, which:

> …acknowledged that PG&E reached its cap in late 2016 and has a waitlist for prospective BIP customers. At that same time, SCE expected to reach or exceed its cap shortly.

At that time, there was a need to prioritize resources fairly and efficiently under the two percent DR reliability cap due to the lack of available headroom in the BIP Program. This is no longer an issue. In contrast to 2016 when there was limited space in the program, PG&E is now significantly below its reliability cap in 2022 and there is a pressing need to grow the program to meet short term reliability needs.

A lottery that only allows for enrollment once per year is unnecessary when there is still existing room below the reliability cap. The flexibility of a rolling enrollment enables more participants to join BIP, while a once-per-year lottery can be prohibitive because it creates both a restricted timeline and uncertainty around available headroom. The annual load impact report, which determines available headroom in BIP, is only released annually in April, which occurs immediately before the lottery is implemented. This creates a lack of visibility in available headroom under the program for aggregators and customers.

2) Minimum Program Enrollment Requirements

PG&E also proposes that a new customer must remain in the BIP Program for at least six months before unenrolling from the

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4 D.18-11-029, Decision Resolving Remaining Application Issues For 2018-2022 Demand Response Portfolios and Declining to Authorize Additional Demand Response Auction Mechanism Pilot Solicitations (Dec. 10, 2018).

5 D.17-12-003 Decision Adopting Demand Response Activities and Budgets for 2018 through 2022 (Dec. 21, 2017).

program or raising the FSL. Under this proposed requirement, a customer who enrolls before July 1 of any given calendar year may unenroll from the program at the end of the calendar year. A customer who enrolls on or after July 1 may unenroll from the program at the end of the following calendar year.

The proposed rule would modify the following requirement issued in D.21-03-05:

> [A] customer who enrolls by April 30th in any given calendar year must be enrolled for at least 6 months before exiting the program. A customer who enrolls after April 30 in any given calendar year must remain enrolled for at least 12 months before exiting the program.

While this language seems to indicate a customer who enrolls after April 30 can unenroll from the program after 12 months, this is not true in practice because the customer can only unenroll from the program during a November unenrollment window. Therefore, a customer under this rule could in theory be required to stay in BIP for up to 22 months. For example, a new customer who is fully enrolled by May 1 of the current calendar year must remain in the program for at least 12 months, but because un-enrollments are only allowed at the end of the year, the customer would be required to be in the program until December 31 of the *next* calendar year—a full 20 months. No other existing PG&E DR requires customers to commit to more than one year of participation. The new rule and lengthy commitment time may discourage new customers from enrolling in the BIP Program. Alternatively, customers interested in the program, but who are concerned about the lengthy enrollment time, may wait to enroll in the program to lessen their time commitment (e.g., a customer interested in enrolling in August 2022 may delay their enrollment to February 2023 to avoid a 17-month commitment to BIP). This may discourage customers from joining BIP during the summer months when load reduction is most needed.

b. Higher Incentives Rates

During Phase 1 of the Emergency Reliability OIR the California Public Utilities Commission (CPUC or Commission) adjusted BIP Incentive rates for 2021-2022 by $1.50/kW from $8/kW-$9.50/kW to $9.50/kW-$10.50/kW to help address short-term reliability needs. In Phase 2 of the Emergency Reliability OIR proceeding, the Commission approved an additional $1.00/kW seasonal increase for May-October only (i.e., the shoulder months would remain at the incentive levels authorized in D.21-03-056) for years 2022 and 2023.[6] Despite these incentive increases and increased BIP outreach efforts, the program has continued to suffer from attrition and stagnating growth. Due to these challenges, coupled with a pressing need to procure more DR resources in the upcoming years,[7] PG&E proposes an additional seasonal incentive increase of $2.00/kW for the months of May-October. PG&E believes higher incentives may motivate customers to enroll and remain in BIP even as capacity needs evolve. A seasonal increase will also attract customers who have high loads during summer when extreme weather events are more likely to occur.

TABLE 3-4
CURRENT AND PROPOSED BIP INCENTIVE RATES

Line No.	Potential Load Reduction	2018-April 2021	2021-2023 Nov-April	2021-2023 May-Oct	2024-2027 Nov-April (Proposed)	2024-2027 May-Oct (Proposed)
1	1 kW to 500 kW	$8.00/kW	$9.50/kW	$10.50/kW	$9.50/kW	$12.50/kW
2	501 kW to 1,000 kW	$8.50/kW	$10.00/kW	$11.00/kW	$10.00/kW	$13.00/kW
3	1,001 kW and greater	$9.00/kW	$10.50/kW	$11.50/kW	$10.50/kW	$13.50/kW

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6 PG&E notes that it advanced the $1/kilowatt-hour (kWh) incentive increase for May-October in the Phase 2 Emergency Reliability OIR Testimony filed September 1, 2021 (See pp. 4-2 to 4-3). The proposed increase in the Phase 2 of the Emergency Reliability OIR was limited to 2022 and 2023; whereas, the proposal herein would also cover the years 2024-2027. PG&E's Opening Testimony, R.20-11-003 (Sept. 1, 2021), p. 4-2, line 20 to p. 4-3, line 13.

7 D.21-06-035, Ordering Paragraph (OP) 5.

c. Change In Event Limits

The current program structure limits events to a maximum of one event per day and 10 events during a calendar month, or 180 hours per calendar year. There is currently no limit to the number of consecutive event days. Under the current structure, BIP participants could, in theory, be called to curtail for up to 20 consecutive event days if the first 10 consecutive days occur at the end of the month and the next 10 occur at the beginning of the following month (e.g., June 21 to July 10).

To prevent customer attrition and encourage new enrollment in BIP, PG&E proposes that: (1) the program events are limited to 10 events during a rolling 30-day window, and (2) a 3-day limit on consecutive event days. A 3-day limit on consecutive events mirrors the PG&E CBP tariff, as well as PG&E's dispatch behavior for most of its DR programs. The limit is a more reasonable requirement for customers that must significantly interrupt their operations for DR events. Modifying the event limits proposed will help address customer concerns around increased RDRR dispatches, prevent further customer fatigue and attrition, and encourage new enrollments.

d. 15-Minute BIP Option

PG&E proposes a 15-minute BIP option in addition to the existing 30-minute-BIP option. BIP participants who enroll under the 15-minute BIP option will be required to reduce their energy consumption to a pre-determined FSL within 15 minutes after an event notice. A 15-minute BIP option can help address emergency grid needs and local capacity requirements, as market resources that can respond in less than 20 minutes can meet local RA requirements.[8] It will also put PG&E in alignment with Southern California Edison Company (SCE), which currently offers both 15-minute and 30-minute BIP options. Incentive levels proposed for the 15-minute option are summarized in Table 3-5.

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8 See pp. 15-16 of CAISO's 2023 Local Capacity Technical Study [2010-12 Long-term LCR Report (caiso.com)] as retrieved on April 27, 2022.

TABLE 3-5
PROPOSED BIP INCENTIVES 2024-2027

Line No.	Potential Load Reduction	15-Minute BIP (Winter)	15-Minte BIP (Summer)	30-Minute BIP (Winter)	30-Minute BIP (Summer)
1	1kW to 500kW	$10.60	$13.60	$9.50	$12.50
2	501 kW to 1,000kW	$11.20	$14.20	$10.00	$13.00
3	1,001kW and greater	$11.80	$14.80	$10.50	$13.50

e. Marketing, Education, and Outreach

The objective of BIP's ME&O efforts is to increase BIP enrollment up to the program's reliability cap, thereby increasing the number of emergency DR resources. PG&E's plan to drive enrollments includes:

- Coordinated BIP outreach campaigns that leverage PG&E's Customer Relationship Managers (CRM) and Marketing team; targeted outreach will consider customers' eligibility, size, industry, and other important attributes for the BIP Program;
- Active encouragement of CRMs to identify and enroll customers into BIP that are a good fit for the program;
- Development of marketing collateral and tools to assist in customer outreach and education; and
- Solicitation of feedback from existing customers to inform program improvements and design changes.

3. Budget and Cost Drivers

PG&E's proposed budget for BIP is summarized in Table 3-6 below.

TABLE 3-6
PROPOSED 2024-2027 BIP BUDGET

Line No.	Expense Detail	2023	2024	2025	2026	2027	Total
1	Administration	$566,000	$583,409	$603,945	$625,204	$647,211	$3,025,768
2	Incentive	31,788,000	43,224,786	43,224,786	43,224,786	43,224,786	204,687,144
3	Total	$32,354,000	$43,808,195	$43,828,731	$43,849,990	$43,871,997	$207,712,912

PG&E's proposed budget for BIP over the 2023-2027 period is $207,713 million. This represents a 28.4 percent increase over the funding authorized for the 2018-2022 cycle. On a cost basis comparison, the BIP

Program authorized for 2018-2022 was $100/kW-year, whereas the costs for 2024-2027 are forecast to be $139/kW-year. The number increases to $141/kW-year if the program qualifies for Automated Demand Response (ADR) incentives, as requested in Exhibit (PG&E-2), Chapter 4.

A significant contributor are the higher incentives authorized by the Emergency Reliability OIR (R.20-11-003),[9] which PG&E carries over to this funding cycle to promote continuity and to forestall potential attrition beyond 2023. The higher rates result in a 19 percent increase in the 2023-2027 proposed incentive budget over the 2018-2022 authorized incentive budget. PG&E proposes an additional incentive increase in this funding cycle, beyond the rates authorized in the Emergency Reliability OIR, which further contributes to the higher cost-basis. Authorized incentive levels for 2018-2022 were $8, $8,50, and $9.00/kW-month for the three load reduction sizes compared to the current proposal of $12.50, $13, and $13.50/kW-month in the summer and $9.50, $10.00, and $10.50/kW-month in the winter. The higher proposed rates, beyond those authorized in the Emergency Reliability OIR, result in an additional 10 percent increase in the 2023-2027 proposed incentive budget when compared to what was theorized over the 2018-2022 program cycle.

As illustrated above in "Table 3-2: BIP Transmission Emergencies 2010-2021," there has been an increased reliance in the past two years on using reliability resources like BIP for systemwide grid emergencies caused by extreme weather events. The need for these emergency resources is forecasted to continue in upcoming years.[10] At the same time, BIP has experienced continual attrition and stagnating growth since 2019, as shown in "Table 3-3: Ex Ante: August Peak." An increase in incentives could help reverse the downward trend in enrollment and further motivate customers to participate in the program.

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9 D.21-03-056 (Phase 1) raised the BIP compensation level by $1.50/kW for 2021 and 2022. D.21-03-056, Attachment 1, p. 18); D.21-12-015 (Phase 2) raised the BIP seasonable compensation (May-October) by $1.00/kW. D.21-12-015, Attachment 1, pp. 4-5.

10 D.21-06-035, OP 6.

4. Cost-Effective Program Alternative

a. Alternative Program Design

As described in Exhibit (PG&E-2), Chapter 9, the proposals in Section B.2 above have a Total Resource Cost (TRC) Test score of 0.82 (including ADR) when analyzed using the 2016 DR Cost Effectiveness CE Protocols (2016 Protocols), and thus are not deemed cost-effective. While not the preferred approach, in this section PG&E puts forward an alternative, cost-effective program design for 2024-2027. Under this alternate scenario, PG&E would:

- Reduce Capacity Incentives:

  Under this alternative scenario there would be no additional $2/kw increase in summer incentive rates (May-October) over the levels currently authorized by the Emergency Reliability OIR (R.20-11-003),[11] as currently proposed by PG&E. Additionally incentive levels authorized by the Emergency Reliability OIR (R.20-11-003) ($10.50, $13, and $13.50/kW-month in the summer $9.50, $10.00, and $10.50/kW-month in the winter) would have to be scaled back to 2018-2022 authorized incentive levels ($8, $8,50, and $9.00/kW-month for the three load reduction sizes). Lastly BIP customers would continue to remain ineligible for ADR incentives.

- Lower Excess Energy Charges:

  Based on conversations with existing customers and third-party aggregators, as well as feedback collected during customer outreach efforts, PG&E believes that the existing excess energy charges are a common barrier for entry for many customers who perceive the risk of the program as being too high. While BIP is a reliability program, there may be customers who can perform well during the majority of BIP events, but cannot risk the high excess energy charges.

[11] D.21-03-056 (Phase 1) raised the BIP compensation level by $1.50/kW for 2021 and 2022. D.21-03-056, Attachment 1, p. 18); D.21-12-015 (Phase 2) raised the BIP seasonable compensation (May-October) by $1.00/kW. D.21-12-015, Attachment 1, pp. 4-5.

To further increase the load impacts attributable to BIP, PG&E could lower the excess energy charges for the BIP Program by 20 percent, from $6.00/kWh to $4.80/kWh (this would not impact the retest rate of $8.40/kWh). The excess energy is any energy (kWh) consumed during a curtailment event that exceeds a customer's FSL. A reduction in the excess energy charge rate could help increase BIP enrollments with little known impact to cost-effectiveness. Excess energy charge rates are currently not factored into the cost-effectiveness model per the 2016 Protocols for the following reasons:

– The cost-effectiveness model assumes an FSL achievement rate of 100 percent. It is unclear at this time if lowering the excess energy charges would have an impact on event performance and FSL achievement rate. PG&E believes the impact to event performance could be minimal but would monitor how any change in excess energy charges for the 2024-2027 funding cycle impacts event performance.

– Funds recovered from excess energy charges are not factored into the cost-effectiveness model per the 2016 Protocol. In any given year, excess energy charges are highly variable due to the number of BIP events called and the performance of BIP participants; therefore, PG&E does not forecast how much funds, if any, will be collected through excess energy charges.

b. Alternative Budget

PG&E's alternative program budget is summarized in Table 3-7 below.

TABLE 3-7
ALTERNATIVE 2024-2027 BIP BUDGET

Line No.	Expense Detail	2024	2025	2026	2027	Total
1	Administration	$583,409	$603,945	$625,204	$647,211	$2,459,768
2	Incentive	26,283,876	26,283,876	26,283,876	26,283,876	105,135,504
3	Total	$26,867,285	$26,887,821	$26,909,079	$26,931,087	$107,595,272

The dollar amounts in the alternative program budgets are lower for the following reasons:

- Incentives rates are $8.00, $8.50, and $9.00/kW-month year-round, which is lower than PG&E's proposed incentive rates; and
- PG&E forecasts substantially lower enrollments for future years (~60 MW per year less than PG&E's proposed program design).

c. Trade Offs

In a cost-effective scenario BIP incentive rates are not increased; instead, it requires a scaling back of the incentive rates that were authorized by the Emergency Reliability OIR (R.20-11-003). PG&E has had limited success with increasing program enrollments at the currently authorized incentive rates, despite targeted outreach efforts from PG&E's account representatives and additional support from PG&E's marketing team. Any new program growth during the past couple years has been offset by substantial attrition. PG&E believes that scaling back, or even keeping, the current incentives rates could have a detrimental impact on already high attrition and low enrollments.

C. Capacity Bidding Program

1. Program Proposals

PG&E proposes several changes and program enhancements with a goal to secure firm DR capacity towards grid stability, increase customer participation, improve program effectiveness and customer experience.

The proposed changes are grouped into two categories. A summary of these categories and changes are enumerated in the following table, followed by the detailed description of each of the proposed changes.

TABLE 3-8
PROPOSED CHANGES CATEGORIES: SUMMARY TABLE

Line No.	Item Detail	2024-2027 Program Changes	2023 Bridge Year Proposals
1	Category Summary and Proposed Changes	Changes proposed in 2024-2027 for CBP are intended to increase program usefulness, increase program participation, improve resource performance when dispatched, and remove hurdles to participation: • Revision to Payment/Penalty Structure; • Removal of Underused Product Options; • Enhanced Testing Process; and • Weekend Participation.	These changes have been proposed in Exhibit (PG&E-1), Chapter 1, Section C.b. of this application for 2023. However, in the event the changes do not get approved for 2023, PG&E is seeking approval to implement these changes in 2024 along with the other 2024-2027 Program changes The following four changes are intended to improve program effectiveness, resource utilization and participation: • Monthly Capacity Incentives; • Program Hours; • Energy Payments; and • Electronic Enrollment. The last three proposals will improve utilization of the capacity within CBP to deliver firm and targeted DR for times of greatest grid need. Additionally, these changes will align the program with RA requirements and the CPUC's and CAISO's resource counting rules: • Nomination Window; • Elect Bid Price Options; and • Recover of RA-Related Market Penalties.

Proposed changes within each group are described in detail below.

a. 2024-2027 Program Changes

1) Revision to Payment/Penalty Structure

PG&E proposes to lower the penalty threshold for CBP aggregators and increase the performance cap, while imposing more severe penalties for non-performance. PG&E believes these revisions will incentivize participation in the program by rewarding higher levels of performance and lowering the penalty threshold, while still recouping costs for severe underperformance.

The 2018-2022 payment and penalty tiers are overly complex with five tiers of payment calculation. Penalties are imposed when the hourly delivered capacity ratio is at or below 60 percent of performance. Payments are capped at a payment cap of

105 percent of performance and are overly complex with five tiers of payment calculation.

Creating a two-tier system will simplify the settlement process for PG&E and aggregators. Lowering the threshold for penalties ensures poor-performing aggregators will face more substantial penalties, with a penalty cap of 100 percent of the total capacity incentive. Increasing the cap for performance to 110 percent will incentivize load reduction at or above 100 percent of nominated capacity, helping to ensure reliable demand reduction. This proposal does not substantially change the total expected incentives for the program. For example, with the new payment tiers, 2020 incentive payments would have been $158,000 (8 percent) higher, with nearly all the additional funds paid to the highest performing (>75 percent) aggregators.

TABLE 3-9
ADJUSTED HOURLY CAPACITY PAYMENT/PENALTY

Line No.	Hourly Delivered Capacity Ratio	Payment	Penalty
1	≥ 0.50 and ≤ 1.10	Unadjusted Hourly Capacity Payment Hourly Delivered Capacity Ratio Capped at 1.10	0
2	≥ 0 and < 0.50	0	Unadjusted Hourly Capacity Payment (1 Hourly Delivered Capacity Ratio)

2) Removal of Underused Product Options

In this section, PG&E summarizes proposals that remove unnecessary complexity from the tariff to ensure program rules can be understood and followed by participants. PG&E believes that removing these options from the program will reduce confusion, remove barriers to participation, and ensure clarity to dispatch events that meet grid needs.

First, PG&E proposes to remove the rarely used Prescribed option. Less than 1 percent of the 2021 CBP portfolio is comprised of Prescribed resources. Aggregators who select this option are typically observed to be participating in CBP for the first time and do not want to add the complexity of understanding market prices. Under this proposal, PG&E will continue to support first time aggregators by replacing the Elect option with bid levels, which will simplify the bidding process. Other aggregators who have selected the Prescribed option in 2021 are those nominating resources for <100 kW, which then require combination with other Prescribed resources in the same Sub-Load Aggregation Point (Sub-LAP) to keep bid price for the combined resource consistent. Again, moving to the bid levels, as described below, will enable the general combination of resources, beneficial for many reasons, including adding optionality for nominations <100 kW.

Second, PG&E proposes to remove all event duration options except the 1-4 hour event duration. The 2-6 hour event duration option of the Prescribed product comprises less than 1 percent of the 2021 CBP portfolio. Between 2018 and 2021 YTD, the 1-8 hour and 1-24 hour event duration options have never been selected. Based on 2020 and 2021 event duration trends, and additional consultation with participating aggregators, PG&E believes the CBP customer base is amenable to the 1-4 hour event duration option in future seasons

Lastly, the Elect+ Option has never been selected to date; thus PG&E proposes to remove it as well.

3) Enhanced Testing Process

PG&E proposes additional testing criteria intended to provide transparency to PG&E, aggregators, and customers, and to ensure testing is meaningful. The current process allows one CBP test event per month, to occur on or after the 20th of the month if a resource has not yet been tested in that program month and if the Prescribed price trigger is met. Test events cannot exceed two hours in duration. Resources are subject to payments and penalties for performance in test events in the same manner as events triggered by market dispatch.

First, PG&E proposes an initial 4-hour test event for all resources with new customers during the first week of the first month in the calendar year that an Aggregator is participating. This test will serve as a learning experience by ensuring systems and customers are prepared to respond to dispatch notifications. Performance during an initial test event will not be counted toward payments or penalties. Events triggered by market dispatch will take precedence over initial test events, and/or can occur after the initial test in the same program month.

Additional test events will continue to be dispatched on a weekday after the 20th of the month if the day-ahead market price exceeds $100/megawatt-hour (MWh) with a maximum duration of four hours, but will also be contingent on:

- Whether the resource has previously been called in the calendar year for real or test events, and whether performance was at or above 75 percent;
- The probability of the resource being dispatched in the remainder of the month for actual grid needs, dependent on PG&E's forecast Sub-LAP temperatures and/or outages; and
- CAISO alerts or notices issued.

These additional criteria will help in prioritizing resources and efficiently identifying only those resources that need to participate in testing events. This will be meaningful for PG&E, aggregators, and customers, while also ensuring that test events are not dispatched when resources are imminently needed to respond to actual market prices and grid needs.

4) Weekend Participation

In 2021, PG&E introduced voluntary weekend participation to provide grid support on any day that experiences high day ahead market prices. This option has been incentivized at 25 percent of the capacity rate, with no discounts or penalties tied to performance, and with the ability for the Aggregator to lower their capacity nomination for Saturday and Sunday.

Starting in 2024, PG&E proposes to convert the current weekend option to require Saturday in order to comply with the 2022-2024 RA requirements for DR as described in D.21-06-029. Currently, CBP requires aggregators to nominate a capacity (MW) amount that is the same for all the program hours from Monday to Friday. There will be no change for this requirement. However, the aggregators will have the ability to lower their capacity nomination for Saturday. Many customers have huge variation in load on Saturdays including no load to reduce when called upon. To accommodate this variance and to align with the RA requirements, the program will allow aggregators to enter 0 kW as capacity nomination for Saturday.

PG&E proposes that capacity payment for Saturday participation will be based on the 25 percent of the capacity incentive (rate) for the applicable month and capacity nomination on Saturday. The performance payment and penalty for Saturday participation will be calculated using a similar method for calculating performance payment and penalty for weekday participation. However, based on the Saturday participation data of 2022 and 2023, PG&E seeks approval to reevaluate and adjust the payment and penalty framework for mandatory Saturday via submission of a Tier 2 Advice Letter.

b. 2023 Bridge Year Proposals

The below listed seven changes are being proposed in Exhibit (PG&E-1), Chapter 1, Section C.b. of this application for 2023. However, in the event the changes do not get approved for 2023, PG&E is seeking approval to implement these changes in 2024, along with the other 2024-2027 Program changes of the listed changes in the previous section.

1) Aligning With RA Requirements

The following category of changes are driven by desire to align CBP with RA Supply Plan requirements.

a) Nomination Window

In 2018 and 2019 CBP nominations were due to PG&E by the 5th business day of the month prior to the operating month. In 2020, based on discussions with aggregators about their accuracy to forecast and commit, PG&E permitted the aggregators to make changes to their nomination up until the 15th day of the month prior to the operating month (T-15). The results of this trial were significant: aggregators increased their nominated capacity by 35 percent when given just 15 more days to submit nominations, a small adjustment to the deadline. In 2021, the program was officially changed[12] to allow nominations to be submitted until the 15th of the month prior to the operating month. With this change, nominations increased by 52 percent from 2020 to 2021.

PG&E anticipates that the Commission will require DR resources be included in year-ahead and monthly RA supply plans beginning in 2023.[13] This will make CBP resource management much more complex, as the current T-15 nomination window does not align with CPUC and CAISO requirements to submit RA supply plans T-45. As such, the CBP Program needs to change to align with resource planning and compliance requirements at the CPUC and CAISO, and resources counting rules.

Accordingly, PG&E proposes to require that capacity nominations be submitted no later than T-70 in advance of the operating month for 2023. This will help ensure CBP resources are created and accounted for in monthly RA supply plans. Aggregators may not reduce the MW nomination value after T-70 but would have until T-15 to provide a full list of

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12 Advice Letter (AL) 6072-E, filed January 28, 2021 and approved February 27, 2021.

13 Flynn, et al., Qualifying Capacity of Supply-Side Demand Response Working Group, California Energy Commission (CEC) Publication No. CEC-200-2022-001-CMF (Feb. 2022), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=241561&DocumentContentId=75526> (as of April 22, 2022). See Chapter 5, Recommendations, pp. 35-37.

participating customers. Aggregators who do not meet their nomination targets by T-15 would be subject to penalties.

While this change will better align DR resources with the RA supply plan framework, PG&E anticipates it could also diminish participation in CBP, as some aggregators may be unwilling to nominate capacity so far in advance of the operating month. An increase in incentive levels may be required to maintain or exceed 2021 capacity nominations going forward. PG&E may propose additional changes to incentive levels proposed in this application after reviewing capacity nomination trends in 2022. Similarly, a change in penalty structure may be required if the aggregators are not able to deliver the committed nomination. PG&E seeks approval to reevaluate and adjust the penalty framework via submission of a Tier 2 Advice Letter.

This proposal is supported by the proposal to refine the Elect option with bid levels, described in the Elect Bid Price Options section below. By offering bid levels, CBP retail resources can be combined within Sub-LAPs and are made eligible for nomination as a Proxy Demand Response (PDR) resource. The PDR resources can be created in advance and maintained throughout the season. The ability to combine retail resources within Sub-LAP, gives flexibility to aggregators to add and/or modify locations while maintaining the MWs they had committed at T-70. This encourages accuracy and new customer acquisition in the program.

b) Elect Bid Price Options

Between 2018 and 2021 the CBP Elect option allowed aggregators to set their own bid price for each resource, between the Net Benefit Test (NBT) price and the CAISO market cap price of $1,000/MWh. Most aggregators selected the Elect option. In 2021, 98.5 percent nominations were for Elect option. This option mitigated customer burnout with higher bid prices that get dispatched less often, and so has contributed to customer retention and growth in PG&E's CBP.

Over time PG&E observed that CBP resources were often underutilized due to high bid prices. For instance, during the August 2020 heatwave,[14] nearly 45 percent of nominated resources were not dispatched while our customers experienced rotating outages. PG&E proposed and received approval for bid cap in Phase 2 of the Emergency Reliability OIR.[15] On February 25, 2022, PG&E submitted AL 6516-E in accordance with D.21-12-015 to implement the approved price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023. Given the extreme nature and likely persistence of extreme heat events, PG&E believes it is reasonable to continue to set the bid cap at $650/MWh for the 2023 Bridge Funding year per D.21-12-015 and through 2027 to ensure CBP capacity is used.

In addition to the continuation of the bid cap, PG&E proposes to refine the Elect option, in which an Aggregator selects any price between the NBT and bid cap for a resource, by instead offering two bid levels: a low bid level and a high bid level capped at $650/MWh. This change will simplify the bidding process for aggregators and PG&E. It will also maintain flexibility in bid prices while adapting the program to evolving regulatory requirements for market participation. Specifically, it will allow PG&E to combine resources at the same bid level within a Sub-LAP, which will create consistency and reduce ongoing operational efforts. Fewer resources per Sub-LAP that remain consistent will also allow resource IDs for each price within a Sub-LAP to be created and put on month-ahead RA Supply Plans well in advance of the trade month without

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14 "Lindsey, *Preliminary analysis concludes Pacific Northwest heat wave was a 1,000-year event…hopefully,* (July 20, 2021), <https://www.climate.gov/news-features/event-tracker/preliminary-analysis-concludes-pacific-northwest-heat-wave-was-1000> (as of April 22, 2022).

15 Opening Testimony in Phase 2, filed September 1, 2021, at p. 4-1. Approval received in D.21-12-015, Attachment 1, p. 4.

sacrificing the ability for aggregators to refine their portfolio and add customers to resources up to the 15th of the month prior.

To further ensure CBP resources are used and useful to the grid, and because bids at lower prices will be dispatched more often, bid levels will be directly tied to capacity incentives: the lower-level bid price will be paid at full capacity incentive rates and a bid price of $650/MWh will be paid at 90 percent of capacity incentive rates. Penalties will not be adjusted.

However, the total number of bid levels, the bid price at the lower level and the capacity incentive derates at all levels needs further analysis and refinement. PG&E seeks approval to reevaluate and adjust the payment and penalty framework for mandatory Saturday via submission of a Tier 2 Advice Letter.

c) Recovery of RA-Related Market Penalties Via the Demand Response Expenditure Balancing Account

The current CBP tariff allows for the assessment of penalties for under and non-performance. As described above PG&E anticipates that the Commission will order DR resources to be shown in RA supply plans. If such an order is promulgated, PG&E's DR resources will be exposed to market penalties associated with putting DR resources on RA supply plans, such as Resource Adequacy Availability Incentive Mechanism penalties. Current tariff rules do not explicitly permit PG&E to recover RA-related market penalties. As such, PG&E requests that RA-related market penalties, be recoverable via Demand Response Expenditure Balancing Account (DREBA).

2) Improving Customer Experience, Reducing Participation Barriers, and Strengthening Value Proposition in Program

The following category of changes are intended to improve the typical customer experience, reduce barriers to participation, and strengthen the value proposition of the CBP.

a) Monthly Capacity Incentives

Except for the increase approved for the month of October in D.21-03-056, CBP's current incentive rates have not been updated since 2018.[16] Increasing incentive rates for month of October, from $2.27/kW to $6.80/kW, resulted in a significant increase in program participation (59.5 percent more nominated capacity in October 2021 versus October 2020).

As illustrated in Table 3-11, PG&E proposes an increase in program incentives for 2023-2027 to align itself with other investor-owned utilities' (IOU) incentive offerings and to stimulate additional interest and participation in the program. The prices are slightly recalibrated and redistributed to ensure all months have prices over $5/kW. The months of July, August, and September remain the highest priced months by far, reflecting expected capacity needs during these months.

TABLE 3-10
CURRENT MONTHLY CAPACITY INCENTIVES
(DOLLARS PER kW)

Line No.	May	June	July	August	September	October	Average
1	$3.18	$3.88	$16.30	$22.54	$13.90	$6.80	$11.10

TABLE 3-11
PROPOSED MONTHLY CAPACITY INCENTIVES
(DOLLARS PER kW)

Line No.	May	June	July	August	September	October	Average
1	$5.64	$6.44	$17.67	$23.82	$14.92	$7.79	$12.71

Earlier in this section, PG&E has proposed significant changes (see Nomination Window and Elect Bid Price Options sections) that favor delivery of firm and targeted DR capacity

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16 PG&E's current CBP incentives were adopted by D.17-12-003, which approved PG&E's 5-year (2018-2022) DR funding application (A.17-01-012).

during times of greatest grid need while aligning with RA requirements and CPUC's and CAISO's resource counting rules. However, without the right incentive structure, it will be extremely challenging to motivate customers to participate and deliver.

b) Program Hours

In 2018, PG&E had two CBP program window options: 11 a.m.-7 p.m. and 1 p.m.-9 p.m. To better align with the RA assessment hours of 4 p.m.-9 p.m., the 11 a.m.-7 p.m. option was removed prior to the 2020 season. PG&E now proposes to limit program hours to the 4 p.m.-9 p.m. window, which is the current window for RA.

In addition to the benefit of aligning with the RA assessment hours, CBP events are rarely called before 4 p.m. Between 2018 and 2021, resources were dispatched for six event hours before 4 p.m. in 2018, resources were dispatched for one event hour before 4 p.m. during the August 2020 heatwave, and resources were dispatched for one event hour d before 4 p.m. in 2021. Furthermore, the 2021 Avoided Cost Curve documentation shows that PG&E experiences peak capacity costs after 3 p.m. and before 10 p.m.,[17] making CBP resources most valuable to the grid between 4 p.m.-9 p.m.

c) Accelerating Energy Payments

Currently, PG&E passes energy payments through to its CBP aggregators as they become available from CAISO. This results in a protracted settlements process, with the first statement based on Settlement Quality Meter Data becoming available 70 business days after an event and final settlement data available after 11 months if there are disputes.

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17 2021 Distributed Energy Resources (DER) Avoided Cost Calculator Documentation for the CPUC, Version 1b (June 22, 2021), p. 56, <https://willdan.app.box.com/v/2021CPUCAvoidedCosts/file/825224047481> (as of April 22, 2022).

PG&E proposes to replace the current pass-through energy payment framework with calculated energy payments and penalties based on CAISO hourly energy prices. This will enable PG&E to align the energy and capacity payment processes, increasing operating efficiency. Furthermore, this change will result in expedited energy payments and lead to a better customer experience. PG&E will submit a Tier 2 Advice Letter detailing the proposed calculation methodology upon approval of the application.

d) Electronic Enrollment

PG&E proposes to continue to allow enrollment via a PG&E-approved electronic process in the tariff, which streamlines the customer enrollment experience

Prior to the 2020 DR season, a change to the PG&E CBP tariff was approved that allows enrollment via "a PG&E approved electronic enrollment pilot process."[18] Over the last year, PG&E has primarily utilized electronic signatures in its third-party Aggregator platform, APX, as well as Enterprise Secure File Transfer (ESFT) as a pseudo-electronic enrollment process for residential aggregators who do not need their customer's interval data, and therefore do not have access to APX. Electronic signatures keep aggregators and customers safe by enabling enrollment that does not require physical interaction. ESFT processes for aggregators that do not need customer interval data allows residential participants to enroll in CBP through their Aggregator.

PG&E is continuing to research other, more streamlined enrollment options for aggregators, including a PG&E Aggregator portal that will have built-in pathways to obtain appropriate access and, eventually, an option to build APIs that can more seamlessly share data from and to the aggregators.

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18 PG&E Electric Tariff Schedule E-CBP, Sheet 4, <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CBP.pdf> (as of April 22, 2022). The pilot was proposed through AL 5752-E-A.

Additionally, there may be an opportunity for PG&E's DR programs to collaborate with the ShareMyData processes to offer a new DR enrollment pathway.

Given the extensive system and process innovation that can be expected between 2023 and 2027, PG&E proposes to continue to allow enrollment via a PG&E-approved electronic process in the tariff, such that it can encompass the spectrum of possibilities for future electronic enrollment. Thus PG&E proposes removal of the term "pilot" from the electronic enrollment process description. This minor change will allow CPUC-approved forms and processes to evolve with our 21st century technical capabilities.

2. Marketing, Education, and Outreach

The objective of CBP's ME&O efforts is to increase CBP awareness and reach, thereby motivating enrollments and increasing the program effectiveness. PG&E's plan to drive enrollments includes, but is not limited to:

- Coordinated CBP outreach campaigns that leverage PG&E's CRMs and Marketing team, including participating in events, such as roadshows and expos;
- Development of marketing collateral and tools to assist in customer outreach and education;
- Solicitation of feedback from existing customers to inform program improvements and design changes;
- Development of research methodology and implementation of market analysis for customer segmentation and targeting based on attributes as customers' eligibility, size, industry, load, and other important attributes for the CBP Program; and
- Development of specific outreach activities and bring program awareness to Community-Based Organizations (CBO).

Marketing expenses, if any, will be covered by the CBP Program administration budget. In the event the administration budget falls short for any critical CBP marketing activity, then PG&E seeks approval to reevaluate and submit the marketing budget via submission of a Tier 2 Advice Letter.

3. Budget and Cost Drivers

PG&E's proposed budget for CBP is summarized in Table 3-12 below.

TABLE 3-12
PROPOSED CBP BUDGET

Line No.	Expense Detail	2023	2024	2025	2026	2027	Total
1	Administration	$538,678	$557,640	$577,269	$597,589	$618,624	$2,889,799
2	Incentive	4,756,072	5,478,514	6,200,955	6,863,193	7,585,634	30,884,368
3	Total	$5,294,751	$6,036,153	$6,778,224	$7,460,782	$8,204,258.01	$33,774,167

PG&E's proposed budget for CBP over the 2023-2027 period is $33.77 million. This represents a 65 percent increase compared to the funding authorized for the 2018-2022 cycle. On cost basis comparison, the CBP authorized for 2018-2022 was $125/kW-year and the cost forecasted for 2023-2027 is also $125/kW-year. While PG&E proposes to increase CBP incentives, the administrative budget for 2023-2027 is lower than that of the prior filing, hence the cost of the program per kW remained about the same.

The main driver for the percentage increase in budget for 2023-2027, as compared to 2018-2022, are the proposed higher capacity incentives. There are significant program changes proposed in 2023-2027 to deliver reliable and firm targeted DR for the times of greatest grid need and to participate in monthly Resource Adequacy Supply Plans. Several program changes proposed in 2023-2027 will address improving participation experience and program usefulness. However, retaining customer and commitment to deliver will be challenging given the proposed large shift in the nomination window proposed in of Exhibit (PG&E-1), Chapter 1, Section C.b.

4. Cost-Effective Program Alternative

a. Alternative Program Design

As described in Exhibit (PG&E-2), Chapter 9, the proposals in Section C.1 have a TRC score of 0.71 (including ADR) when analyzed using the 2016 DR CE Protocols (2016 Protocols), and thus are not deemed cost-effective. The factors attributing to the low TRC are:

1) Changes in the Load Impact Protocol (LIP) ex-ante forecast methodology;

2) Increase in cost due to capacity incentive rates changes; and

3) Decrease in benefits due to load impacts reflecting four hours of DR, rather than five hours.

While not the preferred approach, in this section PG&E puts forward an alternative, cost-effective program design for 2024-2027. Under this alternate scenario, PG&E would:

1) Reduce Capacity Incentives

As described in Table 3-13, by slightly reducing the monthly capacity incentives rates per month, the program increases the net benefit.

TABLE 3-13
ALTERNATE PROPOSED MONTHLY CAPACITY INCENTIVES ($/KW)

Line No.	May	June	July	August	September	October	Average
1	$4.41	$5.16	$16.91	$23.68	$14.69	$7.59	$12.07

2) Adjust Program Hours And Program Event Hour Option

Alternatively, PG&E proposes to extend the program hours to the 4 p.m.-11 p.m. window and proposes 1-5 event hour option.

b. Alternative Program Budget

PG&E's alternative program budget is summarized in Table 3-14 below.

TABLE 3-14
ALTERNATE PROPOSED BUDGET

Line No.	Expense Detail	2023	2024	2025	2026	2027	Total
1	Administration	$538,678	$557,640	$577,269	$597,589	$618,624	$2,889,799
2	Incentive	4,353,557	5,014,857	5,676,156	6,282,348	6,943,648	28,270,568
3	Total	$4,892,236	$5,572,497	$6,253,426	$6,879,937	$7,562,272	$31,160,367

With the slight adjustment in the incentives, the proposed incentive budget is reduced by $2.2 million which reduces the total proposed budget for CBP over the 2023-2027 period to $31.2 million and 2024-2027 to $26.3 million.

c. Trade Offs

Under a cost-effective design, the CBP Program will see a loss of an average of approximately 5 MWs during the peak month of August. As described in Exhibit (PG&E-2), Chapter 7, this design also triggers 5 percent decrease in Load Impacts caused by decreased incentives.

Although extending the program hours to 11:00 p.m. and making 5-hour event option has increased the cost effectiveness, it is likely that the event participation and performance will have a negative impact especially in the last hour of this window. The alternate design assumes that by 2024 aggregators will be able to develop a customer portfolio who are willing to participate in the 5-hour option. This assumption is a risk to the alternate program design. Even though current tariff offers the product option for 2-6 event hours, this is an under-used option in the current program.

The program can be more cost effective if the incentives are further reduced than what is mentioned in the alternate design, but that will be detrimental to the program growth.

In Section C.1 of this chapter, PG&E proposes significant changes that favors delivery of firm and targeted DR capacity during times of greatest grid need while ensuring continued customer participation and engagement. However, without right incentive structure, it will be extremely challenging to motivate customers to participate and deliver.

D. SmartAC™ Program

1. Program Proposals

Considering the ongoing concerns with capacity shortages for the foreseeable future and the substantial reinvestment in the SmartAC Program directed in D.21-12-015, PG&E proposes to continue the Load Control Switch component of SmartAC for Program Years (PY) 2024-2027.

PG&E's SmartAC Program remains a benefit to the California energy grid during times of strain and energy scarcity, the most recent instance being the 2020 August heat wave in which the program provided a peak load reduction of 47 MWs for a single hour. Despite the demonstrated extreme weather impact, as described in Exhibit (PG&E-2), Chapter 9, the SmartAC Program has a TRC Test score of 0.89 (including ADR) when analyzed using the 2016 Protocols, and thus is not deemed cost-effective. Comparatively, the SmartAC Program had a TRC value of 1.3 during the 2018-2022 funding cycle application. The following elements negatively affect SmartAC's cost effectiveness and load impacts:

- Due to the prevalence of solar energy, a shift in peak net demand has led to a shift in the RA hours from 1 to 6 p.m. to 4 to 9 p.m. An average drop of seven degrees happens in the fourth and fifth hours causing less residential AC use and subsequent lower load reduction values for the SmartAC Program;
- The avoided generation cost used to measure cost effectiveness is now measured against storage rather than the historic combustion turbine proxy driving a decline in the avoided cost. Further details can be found in Exhibit (PG&E-2), Chapter 9;
- LIPs and RA rules require the use a 5-hour event dispatch period, even though the SmartAC Program typically dispatches events for the three hottest hours in the RA window. This discussion can be found in Exhibit (PG&E-2), Chapter 7; and
- LIPs and RA rules require the use of a 1-in-2 (average peak) weather condition despite the program operating more closely with 1-in-10 (above average peak) weather conditions. This discussion can be found in Exhibit (PG&E-2), Chapter 7.

The components enumerated above have deteriorated the load impact value per customer for SmartAC. Therefore, despite the program operating on a minimal budget, $26.4 million less than the approved budget from 2018-2022, the program is still not cost effective.

Considering these facts, PG&E proposes the following:

a) Continue the SmartAC Program with the following program parameters starting in 2024:
   - No further customer recruitment efforts will be conducted; however, communications to existing enrolled customers will continue;

- No new customers will be allowed to join the SmartAC Program even if unsolicited; interested customers will be redirected to the Automated Response Technology (ART) Program proposed in Section E;
- Continue to dispatch existing installed two-way devices;
- Continue to be market integrated as a PDR in the CAISO market; and
- Transition the Bring Your Own Thermostat (BYOT) pilot[19] to the ART Program proposed in Section E.

b) Close the Commercial SmartAC Tariff:

PG&E requests approval to formally close its Commercial SmartAC (E-CSAC) tariff. PG&E previously requested to close the commercial SmartAC tariff in the 2018-2022 Mid-Cycle Review (MCR) filing.[20] Since there are no commercial customers currently enrolled, and PG&E

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19 BYOT or "Bring Your Own Thermostat," is PG&E's name for the out-of-market residential smart thermostat control pilot program approved in D.21-12-015, OP 16, with funding of $17.5 million for the period 2022-2023. (D.21-12-015, p. 165, OP 16.) In PG&E's testimony, PG&E called this program the "Smart Controllable Thermostat" or "SCT." (R.20-11-003, PG&E's Errata Testimony (Sept. 2, 2021), p. 4-6, lines 10-11.) The program is described on pp. 4-6 to 4-7 of the testimony as 1) recruiting and providing customers who have [installed smart thermostats on their own with technology for their thermostats], and 2) providing an online store for customers who haven't adopted a smart thermostat yet to obtain one heavily discounted or for free … ." (*Id*., p. 4-6, line 29 to p. 4-7, line 2.) The program provides the online store through which customers can buy the smart thermostat, but does not itself fund the rebates for the smart thermostat. The rebates are funded by other approved programs, including EE, Integrated Demand-Side Management (IDSM) and/or the 2018-2022 DR case.

Another program that uses the acronym "SCT" is the "Smart Communicating Thermostat" program where the Commission authorized a $75 rebate to support customer acquisition of smart thermostats in hot regions of the state. (D.21-12-015, pp. 79-83.) The program to support acquisition of smart thermostats in hot regions of the state is different than the program approved in D.21-12-015, OP 16. To avoid confusion, PG&E now calls the program approved in OP 16 of D.21-12-015, the "Bring Your Own Thermostat" or "BYOT" Program.

20 Proposed AL 5799-E, submitted on April 1, 2020, PG&E's MCR Compliance Submittal for its 2018-2022 Demand Response Funding Application.

cannot enroll new ones,[21] PG&E recommends closure of the E-CSAC tariff that was previously utilized for commercial participants. If the CPUC issues a ruling that concurs with the closure of E-CSAC for the MCR, then PG&E requests authority to file a Tier 1 Advice Letter within 30 days of the decision approving PG&E's request. This Tier 1 Advice Letter would request closure of the E-CSAC tariff, pursuant to the authority given to PG&E in the decision. Alternatively, if an MCR Resolution is not issued PG&E seeks authority to file a Tier 1 Advice Letter to close the E-CSAC tariff.

2. Marketing, Education, and Outreach

PG&E will continue to provide pre-season direct mail and e-mail notifications to customers currently enrolled in the SmartAC Program informing them of expectations for the DR summer season. SmartAC will cease all additional marketing efforts to recruit new customers to the program.

3. Budget and Cost Drivers

A summary of projected program costs annually can be found below:

TABLE 3-15
SmartAC BUDGET

Line No.	Expense Detail	2023[(a)]	2024	2025	2026	2027	Total
1	Administration	$11,370,906	$1,360,735	$1,402,319	$1,445,001	$1,488,817	$17,067,778
2	Incentive	6,257,952	–	–	–	–	6,257,952
3	Total	$17,628,858	$1,360,735	$1,402,319	$1,445,001	$1,488,817	$23,325,730

(a) The 2023 figures in this table include ~$11 million already approved by the Commission via R.20-11-003, such as the BYOT pilot portion of the SmartAC™ Program. For the 2023 Bridge Funding request, PG&E only seeks funding that is incremental to what was approved in D.21-12-015.

21 The SmartAC Program is limited to residential customers since D.12-04-045 closed the program to new commercial participants in 2012. (D.12-04-045, p. 221, OP 38.) While then existing commercial customers were able to remain in the SmartAC Program by now they have attritioned and no commercial participants are enrolled today. However, the legacy tariff (E-CSAC) for commercial participants remains in place since an explicit Commission order has not been issued to close the tariff. The separate E-Residential SmartAC (E-RSAC) tariff for residential participants would not be impacted by the closure of E-CSAC.

4. Cost-Effective Program Alternative

a. Alternative Program Design

Due to the factors described above, there is no scenario in which the program will be cost effective with the current standards.

E. Automated Response Technology Program

1. Program Description

Electrification of home appliances such as heat-pump water heaters, Electric Vehicle (EV) charging and other DERs (e.g., energy storage), will continue to drive an increase in residential energy load. With capacity shortages forecast until 2026[22] and throughout this funding cycle, PG&E proposes to manage this shortfall with a new residential DR market-integrated program, the ART Program. This program will serve to enable customers to leverage their smart home technologies for load management—such as DR and TOU/Load Shifting—beginning in 2024.

The technologies will include, but are not limited to: smart thermostats, smart appliances, HPWHs, EV chargers, and battery—all for load management purposes. An overarching objective of the program will be to promote the use of these technologies to automatically curtail or shift energy use away from the higher cost periods in the customer's TOU rate plan as well as to help mitigate periods of high electric demand on the grid. Allowing ART to dual participate with TOU and possible future real time pricing rates can provide incremental value for our customers as the grid continues to evolve towards decarbonization and high DER.[23]

There are compelling reasons to provide a technology comprehensive program of this type now. A recent CPUC decision established a HPWH incentive within the Statewide SGIP (R.20-05-012 and D.22-04-036) and requires all customers that received the incentive to enroll in a qualified DR program, defined as a CAISO market-integrated supply-side DR program that counts for RA. Based on recent regulatory initiatives, this requirement

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22 D.21-06-035, OP 6.

23 Depending on the structure of the ART incentive(s) and the rate structure, there could be dual payment concerns. Determining incremental value would require that double payment not occur.

may be expanded to other DER technologies such as EV chargers, battery, and smart appliances. PG&E recognizes the need for a new DR program that would help our customers to meet this new requirement and provide them with ways to save energy and money.

As described in the SmartAC testimony in this chapter, a critical challenge for DR programs is achieving cost effectiveness. There are key factors in cost effectiveness calculators that are rendering the value of DR programs to be not cost-effective. In a device-oriented technology program, the challenge can be even greater, due to fees that are being charged by the smart home technology device manufacturers. The scale of these fees is not linked to the amount of DR capacity (kW load impact) provided by these technologies. To mitigate this challenge, the program design for ART will provide a pay for performance incentive structure for third party implementers. Customers may also be paid on a pay for performance basis, contingent upon the incentive design proposed by the third-party implementers. Technology incentives to promote adoption of the devices will be provided under other funding mechanisms, such as: EE, SGIP, IDSM, and EV initiatives.

2. Program Proposal

The program design of ART provides the ability for PG&E to leverage the expertise of multiple third-party implementers, or possibly a single implementer, who will provide critical implementation services for PG&E. Upon approval of ART, PG&E will conduct a Request for Proposal (RFP) to select well-qualified and competitive provider(s) for implementation services which include integrations with Original Equipment Manufacturers, customer incentive management, enrollment and disenrollment work flows and various program-related communications with customers. The program goal is to provide value as early as the summer of 2024, PG&E will leverage experience over recent years from various pilots and Demand Response Emerging Technology (DRET) studies to create criteria to efficiently assess submissions from the RFP. As PG&E operates the program, it will also conduct an exploration to assess if the ART Program should expand to include other Demand Response Providers (DRP). If there is interest from

DRPs and it appears to be feasible and cost effective, PG&E will propose this expansion in the 2028 DR program cycle.

Using the existing capacity value, PG&E developed a cost-effective budget for the ART Program of $23.8 million over the course of PYs 2024 through 2027 with an estimated program MW impact of approximately 104 MW.

Table 3-16 below outlines the composition of ART Program designs: Items 1-7 are the foundation of the program and Item 8 includes design elements that PG&E will solicit during the RFP process.

TABLE 3-16
AUTOMATED RESPONSE TECHNOLOGY PROGRAM
DESIGN PARAMETERS

Line No.	Item Detail	ART Program
1	Availability	Year around, 4-9 p.m., Monday to Sunday, subject to change if the CPUC changes the peak TOU period. Inception date-May 1, 2024
2	Enrollment and Eligibility	Residential bundled and Community Choice Aggregation with electric service. Direct enrollment.
3	Triggers	Day ahead based on CAISO market award dispatch. Day ahead PG&E system emergency or near-emergency for distribution service.
4	Market Integration	Market Integrated as Proxy Demand Resource.
5	Dual Participation	Customers not on any other PG&E or DRPs supply-side DR program.
6	Technology Enablement	At least one of the following technologies is required for participation: • Smart Thermostat; • EV; • Battery; • HPWH; • Smart Appliance; and • Other as identified.
7	Time varying function	All technologies are required to support daily automatic load management function(s) for TOU or any other time varying price rate plan (e.g., Real-Time Pricing)
8	Other Program Designs Elements for Consideration	PG&E will solicit third-party innovative design ideas on the following program parameters: • Customer incentive (i.e., pay for performance, fixed payment, penalty); • Payment options (e.g., gift cards, check, cash, gamification); • Payment terms (i.e., post event, monthly, annual); • Technology manufacturer fees; • New technology intake process; and • Marketing strategies and tactics.

3. Marketing, Education, and Outreach

PG&E will leverage many residential ME&O channels in promoting ART to residential customers which include, e-mail, digital, residential newsletters, and bundling and co-marketing, to name a few. In working with the third party(ies), PG&E provides review of vendor created materials for accuracy and privacy/cyber security and also conducts accessibility testing. PG&E typically sends all promotional outreach materials while vendors send communications to program participants, such as welcome and event notifications.

Additionally, PG&E will promote ART and other residential programs on the new online platform detailed in Section G.3., which will guide customers in making choices for DR programs with the objective to increase residential adoption of BTM technologies.

4. Budget and Load Impact

PG&E's proposed budget for ART is summarized in Table 3-17 below.

TABLE 3-17
PROPOSED AUTOMATED RESPONSE TECHNOLOGY BUDGET
PROGRAM BUDGET

Line No.	Expense Detail	2024	2025	2026	2027	Total
1	Administration	$1,123,703	$1,249,475	$1,261,925	$1,124,145	$4,759,248
2	Implementation and Incentives	4,494,813	4,997,900	5,047,700	4,496,580	9,036,993
3	Total	$5,618,517	$6,247,375	$6,309,625	$5,620,725	$23,796,242

5. Megawatt Impact Values

Estimated MW impact values for technologies are based on the results of recent impact assessments of smart technologies and behind-the-meter (BTM) DER under the DRET Program. PG&E believes that improvements in the following areas may result in an even more cost-effective program offering as the technologies continue to mature: (1) increased MW impacts from participating technologies, (2) stacked grid services to increase overall value (e.g., ability to provide RA capacity and energy, distribution deferral, greenhouse gas reduction), and (3) reduction in overall system and platform cost. A more cost-effective program will allow PG&E to increase the attractiveness of the program to third parties and customers.

Measurement and evaluation of the program will be included as part of the annual April 1 DR load impact filing. See estimated impact in Table 3-18 below.

TABLE 3-18
AUTOMATED RESPONSE TECHNOLOGY PROGRAM
ESTIMATED DEVICE COUNTS AND LOAD IMPACT

Line No.	Technology	MW Impact Per Device (kW)	Cumulative # of Devices	Total Load Impact (MW)
1	Smart Thermostat	0.57	120,000	66.0
2	EV	0.35	25,000	8.0
3	Battery	2.5	12,500	28.6
4	HPWH	0.05	10,000	0.5
5	CEC Flexible Appliance (Example: Pool Pump and Electric Clothes Dryer)	0.05	20,000	0.9
6	Total			104.0

F. Load Modifying Resources

PG&E previously integrated its DR programs into the CAISO's market. However, there are several Load Modifying Resource (LMR) DR programs funded through the DR applications, including: the PLS, the OBMC Program, and the SLRP. The three LMR DR programs are discussed below.

1. PLS-Thermal Energy Storage

a. Program Proposal

Per CPUC directive in D.17-12-003, PG&E has *closed* the Permanent Load Shift-Thermal Energy Storage Program to new applicants. As previously described in Exhibit (PG&E-1), Chapter 1, Section 2.c. of this application, PG&E proposes to end the requirement to submit five years of monitoring data for performance evaluation.

2. Optional Binding Mandatory Curtailment

a. Program Proposal

PG&E proposes to continue the OBMC Program and is not recommending any changes. Despite the lack of activity historically, the increasing challenges imposed on the grid by extreme weather events and wildfires have increased the occurrence of CAISO Staged

Emergencies,[24] thus it is prudent to keep the capacity enrolled in OBMC available.

3. Scheduled Load Reduction Program

a. Program Proposal

PG&E is not proposing changes for SLRP but notes that this program is enshrined in Pub. Util. Code Section 740.10 and cannot be closed without legislation, regardless of participation levels. The SLRP will remain open until terminated by state legislation; however, the program has no customers enrolled.

4. Budget and Cost Drivers

PG&E's proposed budget for all Load Modifying programs is summarized in Table 3-19 below.

TABLE 3-19
PROPOSED LOAD MODIFYING RESOURCES BUDGET

Line No.	Expense Detail	2023	2024	2025	2026	2027	Total
1	Administration	$7,992	$8,273	$8,565	$8,886	$9,178	$42,875
2	Incentive	–	–	–	–	–	–
3	Contract	–	–	–	–	–	–
4	Total	$7,992	$8,273	$8,565	$8,886	$9,178	$42,875

PG&E's proposed budget for its Load Modifying programs over the 2023-2027 period is $42,875. This represents a 32 percent decrease, compared to the funding authorized for the 2018-2022 cycle. On cost basis comparison, the OBMC and the SLRP Program authorized for 2018-2022 was $63/kW-year, whereas the costs for 2024-2027 are forecast to be $35/kW-year.

The main driver for the percentage decrease in budget for 2023-2027, as compared to 2018-2022, are no new enrollments in these programs. There are no program changes proposed in 2023-2027. The requested funding is only for the continued operation of the OBMC Program.

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[24] CAISO, Summary of Restricted Maintenance Operations, Alert, Warning, Emergency, and Flex Alert Notices Issued from 1998 to Present (Dec. 2, 2021), <http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf. (as of April 22, 2022).

G. Marketing, Education, and Outreach for DR Portfolio

1. Objectives

PG&E's portfolio of DR programs and pilots allow business and residential customers to support the grid, while simultaneously accruing individual financial, reputational, and/or societal benefits. Given the diversity in customer needs and capabilities, PG&E seeks to utilize ME&O strategies to connect customers to DR offerings that best fit their household or business, while serving the needs of the electric grid.

In addition to PG&E's multitude of DR offerings, PG&E is committed to supporting the Commission's goals of increasing the role of third-party DRPs. Through partnerships, PG&E works collaboratively with third-party DRPs on ME&O-related items, which ultimately create further opportunities to enable more DR to serve grid needs.

To achieve the desired outcome of connecting customers to DR offerings that best fit their needs, the following three ME&O objectives are defined below:

- Education and Outreach: Increase customer awareness and understanding regarding the role of DR as a grid resource and the customer requirements and the benefits of participating.
- Customer Acquisition: Drive customer enrollments in DR programs, whether through PG&E directly or through a third-party DRP.
- Customer Retention: Maintain relationships and communication channels with current program participants. Solicit feedback to inform future program improvements, as well as update customers on program design changes.

2. Approach

PG&E intends to leverage its past outreach efforts, customer feedback and operational experiences to inform ME&O strategies that will achieve the objectives noted above. Elements of these strategies bolstered customer acquisition efforts for summer 2021. PG&E believes these strategies have the potential to continue delivering on the ME&O objectives of increased awareness, acquisition, and retention for PG&E's DR programs.

- Customer and Technology Segmentation: PG&E will develop a framework to inform targeted ME&O efforts based on customer or technology segmentation. A fundamental pillar of participation in PG&E's DR non-residential programs is that they are technology-agnostic—the type of BTM technology on the customer's premise should not limit a customer's eligibility to participate in a DR program. However, there is recognition that different technologies have different capabilities to provide load reduction or load shift. This variance can be further exacerbated when the variable of customer behavior is added, which ultimately influences how the technology performs. With this understanding, certain customers and technologies may be better suited for one DR program over another.
- Coordinating DR Outreach: Informed by the customer and technology segmentation, PG&E will continue to seek new opportunities for coordinating marketing with other relevant customer programs and including DR options within integrated channels such as the residential and business digital newsletters, as appropriate. Areas of continued coordination with DR include: the Energy Savings Assistance Program, Disadvantaged Communities, and CBOs where there are combined efforts to conduct outreach and education of EE and DR to lower-income customers. PG&E also sees value in increased coordination on both policy and marketing efforts between DR and customer programs that incentivize the installation of BTM energy systems, such as the SGIP.
- Annual Summer Readiness: The need and value of DR is highest during the summer season (May-October). Prior to the start of the summer season, PG&E intends to conduct a series of ME&O campaigns to prepare, educate and acquire customers. Each campaign will build on the preceding one to create a comprehensive customer engagement. For example, initial campaigns may communicate the various DR offerings and subsequent campaigns may be more targeted based on customer-specific attributes, such as industry or energy usage patterns. While PG&E will make concerted outreach efforts in advance of

summer, it will also maintain ongoing efforts throughout the year to support program-specific DR education for customers and stakeholders.

- Leverage Relationships and Partnerships: PG&E plans to leverage internal relationships and external partnerships as an additional channel to connect with customers, leveraging existing relationships to provide trusted insight into DR programs. Internally, PG&E will rely on its Customer Relationship Managers who will utilize a suite of sales enablement tools and resources to facilitate non-residential customer interactions. Externally, PG&E plans to leverage the existing relationships that trade groups, CBOs, and third-party DRPs have with customers. PG&E can engage collaboratively with parties to develop marketing strategies or provide parties with existing, pre-developed DR program collateral to ensure familiarity and effectiveness in outreach efforts.

In addition to these efforts, PG&E plans to drive traffic and engagement with DR webpages on pge.com. Where applicable, self-service tools like: program manuals, incentive calculators, case studies, and public industry resources may be promoted to inform customers of what participation in a DR program entails. PG&E plans to give preference to electronic outreach methods that can be more cost-effective, such as e-mail or digital search marketing. This outreach will be supplemented with person-to-person outreach where feasible (e.g., educational workshops and participation in community and industry events).

As described in Exhibit (PG&E-2), Chapter 2, PG&E proposes to run a Load Flexibility Study over the 2024-2027 period. The study's objectives are to understand PG&E customer elasticity by end use, identify usage patterns of specific BTM DER and smart appliances, and determine how the load reduction and flexibility potential of these devices could be optimally-leveraged. Insights gained from this study will be factored into ongoing ME&O efforts.

3. Online Platform for Residential DR Offers

a. Problem Statement

Opportunities for residential customers to engage with DRPs—whether third parties or PG&E, with or without BTM smart technologies—are ever increasing. Smart lightbulbs, smart thermostats, EV charging, batteries, just to name a few, all proclaim the benefits to customers to lower energy use and costs through management of the technology. Promotions by PG&E and third parties entice customers into DR programs by providing enrollment incentives and offsetting the purchase price of technologies with rebates in exchange for allowing remote adjustments of the technology's settings during periods of high demand. Considering long-standing residential program options, proposed pilots, potential technology assessments, and field studies, customers can easily be confused by their choices to engage.

b. Approach: Guide Customers in Making Choices

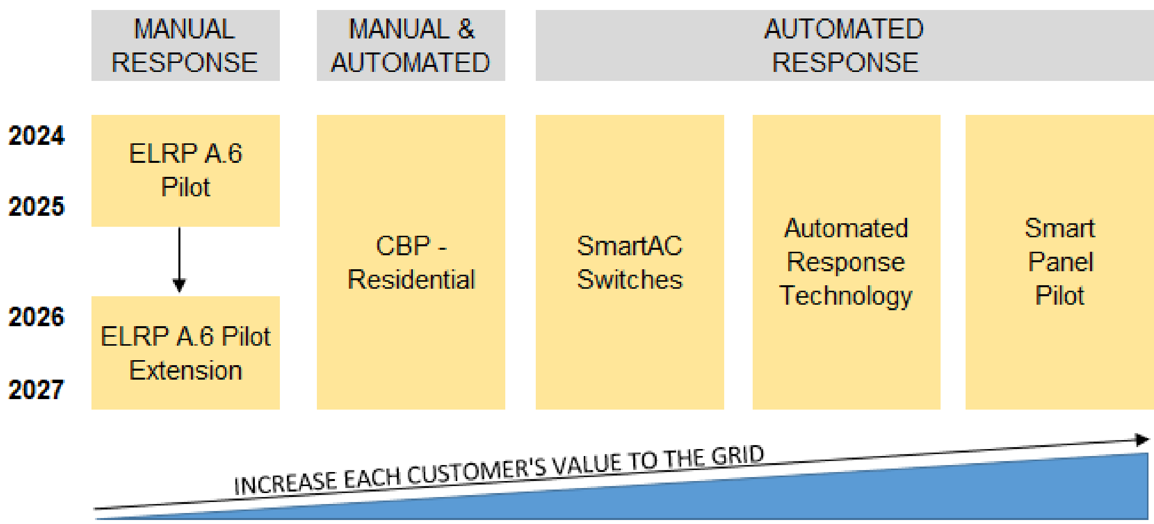
To improve the residential customer experience, PG&E is creating an online platform that will provide an overview of the DR programs that are available through PG&E. Based on PG&E data and information provided by the customer, the platform will be evolved to provide tailored recommendations across PG&E offerings, including, but not limited to DR programs; and incentives and tools related to other Demand-Side Management opportunities in: EE, EVs, distributed generation, and resiliency.

Looking across the landscape for PYs 2024 through 2027, PG&E's residential direct-enrolled programs offer a suite of programs for customers to choose from that includes:

- The continuation of ELRP A.6 authorized through 2025 and proposed in Exhibit (PG&E-2), Chapter 4 to continue through 2027;
- CBP-Residential;
- The proposed ART Program, which includes the onboarding of more enabling technologies; and
- The Smart Panel Pilot proposed for 2024 through 2027 to control all loads in a home through the web or an app.

Figure 3-1 provides a graphic overview of the suite of PG&E residential programs and proposals that would align under the online platform:

FIGURE 3-1
RESIDENTIAL DR PROGRAMS



The online platform is a PG&E companywide initiative which will launch in 2022 as a replacement of the current marketplace and is being developed in phases. By 2024, the functionality described in this section will be available. DR will be contributing to the overall costs and those have been factored into the ME&O budget.

c. Objective: Increase DR Program Participation

The overarching goal of the online platform is to provide customers with an integrated experience which guides them in making choices and encourages them to increase their engagement to support their own energy management goals. The programs offered by PG&E attempt to ensure that most residential customers in PG&E's territory are participating in DR programs. Manual responding customers historically offer lower load reduction value than customers with technologies that can automate their response. IOUs estimate an average value of 0.03 kW per customer in the ELRP A.6 pilot. A SmartAC switch or BYOT participants, on the other hand, offer an average value of

~0.50 kW per customer while the discharge of a battery can offer ~2.5 kW per customer.

Offering a more simplified approach to educate customers about the opportunities available to them under one online platform, versus separate program offers, could be a means to achieving higher adoption rates of automated technologies and enrollment into DR programs.

There are different ways to enable customers to make choices among the options available. An effective approach incorporates assessing customer motivations, as well customer preferences for comfort and control. Typically, this is done through customer self-identification or with leading questions. Incorporating data on customer preferences helps to present choices in line with their historical preferences.

The new platform will describe the myriad opportunities for customers to receive rebates and incentives and will help them to understand the value propositions of the various DR programs. PG&E has done an initial round of customer research to help inform platform development and will continue to bring customers into the process to ensure that the final product is beneficial to customers.

H. Conclusion

PG&E's proposals for programmatic changes are focused on strengthening its current DR portfolio for CAISO supply side resources (BIP, CBP, and SmartAC) and for maintaining its LMRs, which today consists of the OBMC Program.[25] These proposed modifications build on elements that were adopted as part of the Emergency Reliability OIR (R.20-11-003) and will help support grid needs during the 2024-2027 funding cycle. PG&E also proposes to erect a new residential ART Program that will enable customers to leverage multiple technologies for load management, such as DR and TOU/Load Shifting beginning in 2024. Lastly, to improve the residential customer experience, we propose creating an online platform that will provide an overview of the DR programs that are available through PG&E.

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[25] While PG&E's DR Operations supports rate-based Critical Peak Pricing (CPP), such as SmartRate™ and PDP; funding for CPP is outside of the DR Application.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

2024-2027 DEMAND RESPONSE TECHNOLOGY PROGRAMS, PILOTS AND LOAD MANAGEMENT PROPOSAL

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A. Introduction

This chapter lays out Pacific Gas and Electric Company's (PG&E) commitment towards a vibrant, reliable, and cost-effective clean energy future by focusing on our customers. Customers are a critical component to unlocking this future, and it starts by providing customers access to Load Management tools encompassing behind the meter (BTM) Distributed Energy Resource (DER) and smart appliance technologies, as well as access to pricing, education, and programs. If done correctly, Load Management can help customers with flexibility and reliability that they need based on their energy agenda and the utility grid will benefit from such actions.

To realize this future, PG&E is proposing to continue several existing initiatives and to create new initiatives as described in this chapter that are divided into three sections:

a) Demand Response (DR) Enabling Technology and Programs;

b) 2024-2027 Pilot Activities; and

c) Load Management Activities.

All three areas complement one another, and activities and proposals are focused on solving some of the current critical challenges facing DR today, which are mostly centered around: (1) the ability of DR resources to deliver reliable and firm response, (2) customers demand elasticity and (3) the challenge around demand-side programs being siloed thereby creating confusion as to whether a customer is eligible to *dual participate* (multiple participation, value stacking). The activities presented in this chapter will help pave the way towards the types of program design requirements to make demand side more reliable and develop data points and further insights on the impacts of dual/multiple participation rule on programs and technologies where customers elect to adopt.

DR Enabling Technology and Programs encompasses Demand Response Emerging Technology (DRET), Automated Demand Response (ADR) Program, and Integrated Demand Side Management (IDSM). Different technologies have different operating characteristics, which when combined with the customer's primary functional use of the technology, creates variability in the expected load impacts—reducing DR firmness. Even among the same technology, different original equipment manufacturers have different device integration pathways, which still yield varying abilities to perform DR, again challenging the ability to scale. Leveraging these three technology focused programs will support the development of scalable approaches and solutions, which address stacking of the various PG&E customer programs and provide customers with necessary experience and solutions.

Pilot efforts in 2024-2027 are concentrated on redesigning and testing new DR program design approaches, varying ways to interact with customers and continue to evaluate opportunities such as exporting of energy. The Smart Panel Pilot focuses on residential customers and how smart electrical panels may help customers solve and achieve whole home controls while allowing PG&E to test new DR design that centers around demand limiting opportunities. The Emergency Load Reduction Program (ELRP) Pilot is an emergency pilot that is testing nascent but promising opportunities with virtual power plants (VPP), vehicle-grid-integration (VGI), and residential auto-enrollment, while enabling new opportunities such as export and exploration of sub-metering. The DR Agricultural Pilot will evaluate and test designs that would enable greater participation from the agricultural customer segment.

Load Management Activities focuses on supporting the development of the California Energy Commission's (CEC) Load Management Standards and activities supporting demand flexibility to give customers and third parties information needed to make decisions based on customer preference and priorities on control and various time varying rates including dynamic rate.

Together, these three areas are pathways which PG&E will utilize as a testbed to develop new knowledge, technologies and operational experience which strive to enhance DR resources by bolstering firmness while supporting the customer experience. The outline of this chapter and summaries of PG&E's recommendations may be found in Table 4-1 below.

TABLE 4-1
SUMMARY OF DR ENABLING TECHNOLOGY AND PROGRAMS, PILOTS, AND LOAD MANAGEMENT PROPOSALS

Line No.	Section	Proposal	Customer/Grid Benefit
1	B.1. ADR	Approval of the Auto-DR program: - Continue Standard Application process with option for customers to choose between 60/40 (3-year commitment) or 100% upfront (5 year commitment) - Expand FastTrack Application process to other customer segments and measures - Discontinue Residential Deemed Incentive Application - Qualify Emergency Programs (e.g., BIP) as an eligible DR program for ADR	The ADR Control automates participation in DR events to ensure customers provide reliable load shed during DR program events. This allows customers to earn more performance incentives from DR program and increase DR resource reliability at the same time.
2	B.2. DRET	Approval and continuation of the DR DRET Program.	DRET study and assessments are designed to explore new opportunities, potential enhancements and technology evaluation to the existing DR portfolio by informing the ongoing development and improvement of PG&E's DR and dynamic rates pilots and programs.
3	B.3. IDSM	Continue IDSM program until the end of 2025 as ordered in EE Business Plan (D.18-05-041). Beyond 2025, PG&E will continue IDSM if approved in EE Business Plan (2024-2031). PG&E will continue to identify integration strategies across the various customer programs (EE, DG, CET, DR)	The intent of integrating DSM programs is to achieve maximum savings while avoiding duplication of efforts, reducing transaction costs, and diminishing customer confusion on DSM programs.
4	C.1. Smart Panel Pilot	Approval of the Smart Panel Pilot for years 2024-27. Pilot will test demand limiting DR program design evaluating whether smart electrical panel can provide simple "whole home" controls for customers to achieve energy goals while providing grid value. Smart electrical panel will test multiple use grid services.	Smart electrical panel will be a critical technology for customers as they electrify their home. Smart electrical panel offers multiple capabilities and value for both customers (e.g., bill savings, electrification) and grid (e.g., customer demand limiting program can offer grid operators with more predictable and reliable response from customers).

TABLE 4-1
SUMMARY OF DR ENABLING TECHNOLOGY AND PROGRAMS, PILOTS, AND LOAD MANAGEMENT PROPOSALS
(CONTINUED)

Line No.	Section	Proposal	Customer/Grid Benefit
5	C.2. ELRP	Approval of the ELRP Pilot until the end of 2027. Continue to offer an emergency program pilot ensuring additional demand side resources when CAISO grid is stressed, forced outages due to wildfires, and imminent of rotating outages. PG&E will continue to utilize end of year Tier 2 Advice Letter process to enhance ELRP Pilot to meet the evolving grid challenges.	ELRP provides CAISO grid operators with an additional resource when emergencies are imminent and prevent possible outages.
6	C.3. Agricultural DR Pilot	Grow DR participation and load reduction among the agricultural sector by developing and testing an agricultural specific DR program design	Increase opportunities for agricultural customers to participate in demand response, with an estimated 17.5 MWs of estimated load reduction under a fully ramped up pilot program
7	D.1. Load Management Activities	Approval for PG&E to file Tier 2 Advice Letter to release funds to support the CEC Load Management Standards and development and enhancements of systems integrating with CEC MIDAS price portal.	Supporting CEC Load Management Standards and integrating with MIDAS will provide customers and third parties (providing support to customers) with price signals leading to possible automated response from customer technologies – enablement of flexible demand

B. Demand Response Enabling Technology and Programs

1. Automated Demand Response

a. Program Description

PG&E's ADR Program provides rebates and incentives to help customers offset the purchase and installation costs of new BTM DER technologies (e.g., energy efficient devices, and electric vehicle (EV) charging stations) and controls (e.g., energy management systems, heating, ventilation and air conditioning (HVAC), lighting, agricultural pumps and refrigeration) that are capable of receiving ADR signals for DR events. The ADR signal triggers pre-programmed and automated energy management and curtailment strategies that PG&E develops in collaboration with the customer and the vendor providing the ADR-enabled devices. Automation reduces the burden on customers to manually reduce their energy usage and improves the firmness of the load reduction.

Customers receiving ADR incentive are required to enroll in a qualified DR program, which include both market integrated programs such as Capacity Bidding Program (CBP) and Demand Response Auction Mechanism (DRAM), and non-market integrated dynamic rate such as Peak Day Pricing and Residential Smart Rate. The ADR Program offers three application processes which have typically accommodated different customer sizes and segments:

- The **Standard Application** process is primarily for large commercial, industrial and agricultural customers. This approach requires a robust calculation of curtailment kilowatt (kW) in accordance with ADR Program standards typically prepared by engineers and analysts. The objective is to assess the new ADR control technology project for reliability and consistency of performance during DR events as it pertains to the DR program in which the customers are enrolling. The ADR Team staff uses an analysis methodology vetted with Lawrence Berkeley National Laboratory and a 3rd party implementation vendor. Using a consistent methodology ensures that similar projects are treated comparably and fairly.
- The **FastTrack Application** process is available for small and medium business (SMB) who have an average peak summer demand that is ≤ 200 kW per Service Account Identification (SAID), along with specific sectors of business customers who have under 499 kW average peak summer demand per SAID. Currently, eligible sectors for this application include retail, office, quick serve restaurant, air-conditioned warehouse and grocery stores. This approach provides a streamlined incentive calculation process for projects associated with specific building types and for HVAC and lighting. The FastTrack incentive calculation process requires only five inputs to determine the potential ADR incentive which is in contrast to the Standard Application process.
- The **Deemed Incentive Application** process is available for residential customers. As of the filing of this application, the only measure that is eligible for a residential ADR incentive is a smart

thermostat rebate of $50. Starting 2024, PG&E is proposing to eliminate the Deemed incentive application process and incentive.

b. Regulatory Background

The ADR Program was first approved for 2006-2008 in Decision (D.) 06-03-024 and D.06-11-049. The program structure remained the same for 2009-2011, approved in D.09-08-027, and remained the same in 2012, approved in D.12-04-045. The ADR Program merged two separate programs, the Technical Assistance and Technology Incentive Program, which was later renamed ADR, and which provided incentives for audits and semi-automatic technologies and the ADR Program. Incentives were paid 100 percent upfront and could not exceed 100 percent of total project costs. Customers could allow their incentive to be paid to their third-party project sponsors.

For the 2013-2016 program cycle, approved in D.12-04-045, a new incentive structure was introduced restricting to only 60 percent of the incentive to be distributed after confirmation of technology installation with the remaining 40 percent distributed based on the customer's performance in their first year of DR performance. PG&E established the FastTrack program during this cycle to provide deemed incentives to customers installing DR controls for lighting and HVAC measures for limited sectors of customers. This application process was not subject to the 60/40 percent incentive distribution structure and incentives were paid 100 percent upfront.

In 2016, the ADR Program was approved in D.16-06-029, which set the ADR incentive to $200/kW statewide and with a not-to-exceed limit of 75 percent of total project costs.

For the 2018-2022 cycle, approved in D.17-12-003 and further clarified in D.18-11-029, the California Public Utilities Commission (CPUC or Commission) included policy changes which prohibited ADR control incentives for customers participating in reliability demand response resource (RDRR), devices unable to receive the ADR signal, and battery storage controls for applications received after October 25, 2018. Additionally, in these decisions the CPUC established an annual stakeholder process and authorized Energy Division to work with the

Investor-Owned Utilities (IOU) and other stakeholders to identify a set of ADR issues to be resolved each year:[1]

A CPUC-identified issue that remained unresolved from D.18-11-029 (Ordering Paragraph (OP 9)) is the "Review of the approach to calculate control incentives." In late 2019, the IOU led an ADR Non-Residential Incentive Structure Research Project Report (Research Project) that was conducted by a third-party to review the approach to calculate control incentives, with the objective of identifying a new approach for non-residential customers. Although the Research Project report contained a dense repository of data and information, along with recommendations, the IOUs did not agree with the recommendations. Additionally, stakeholders did not submit feedback on the report or recommendations. The IOUs have leveraged the information in the Research Project report to continue to review the approach and potential new approaches to calculating incentive structures through frequent work sessions. A virtual workshop was held on March 15, 2021, to solicit feedback from stakeholders on various ideas for new incentive structures. The workshop resulted in limited feedback.

c. Program Proposal

As explained in the Regulatory Background section, the IOUs have conducted extensive review of the incentive approach for the non-residential component of the ADR program. PG&E and Southern California Edison Company (SCE) have aligned on proposing the following modifications for the 2024-2027 ADR Program non-residential component.

d. Incentive Payment Split for Standard Application

PG&E proposes to continue to offer the option that was approved under D.21-12-015[2] of 100 percent payment after the installation of the technology is confirmed as dispatchable and DR program participation is

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[1] D.18-11-029, pp. 106-107, OP 8.

[2] D.21-12-015, p. 149, Findings of Fact 115 and p. 156, Conclusions of Law 44.

verified. The 100 percent payment option is in addition to the existing 60 percent paid upfront and 40 percent after a full year of DR program participation option.

FIGURE 4-1
ADR MEGAWATT (MW) BY YEAR, ALL IOUS

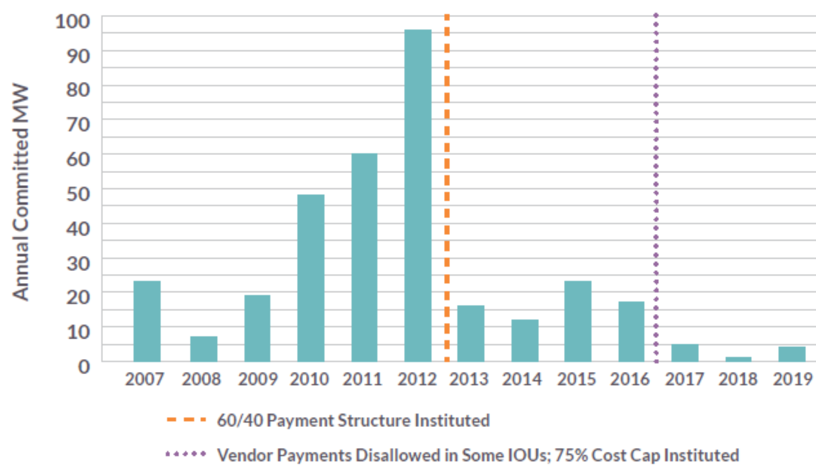

Figure 4-1 presents conclusions from the Research Project, and it demonstrates the dramatic decline in interest in the program after the change in 2012 to the 60/40 distribution of incentives.[3] Although there was a push to get projects completed before the change took place, it is clear that customers have difficulty carrying the costs of implementing a DR project through a customer's first DR season, which can, in reality, extend into year two of installation. PG&E will be tracking the preferences of customers to assess for trends by business sector and will be monitoring key metrics such as duration in a DR program and load reduction commitments versus actual performance.

e. Demand Response Program Participation Requirement

PG&E proposes to expand the DR program participation requirement from three years to five years as an option if the customer chooses to receive 100 percent of ADR incentive upfront.

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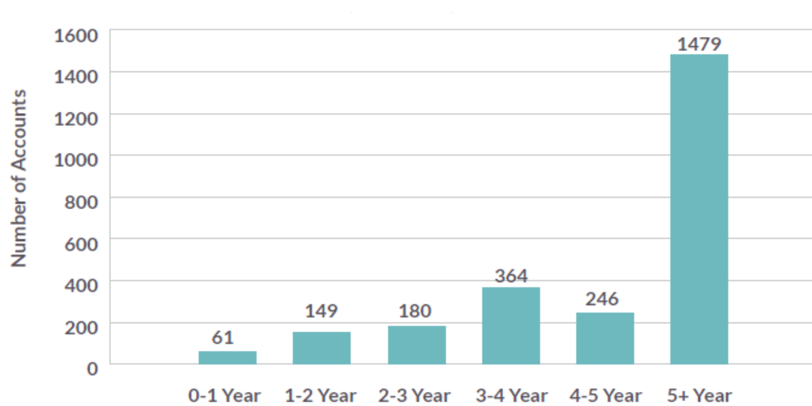
3 CALMAC: "Automated Demand Response Non-Residential Incentive Structure Research Project Report", (Aug. 6, 2020), CALMAC Study ID PGE0452.01, p. 39, Figure 17, <http://www.calmac.org/publications/Automated_Demand_Response_Non-Residential_Incentive_Structure_Research_Project_Report.pdf>, (as of Apr. 21, 2022).

The Research Project documented that 84 percent of accounts do remain in a DR program for three years and 60 percent stay enrolled for five or more years.[4] PG&E has clawed back ADR program incentives when this requirement is not met in the past and has enhanced program materials to strengthen the messaging so that customers and project sponsors are very aware of the risk. See figure 4-2 for the number of customers that completed their 3-year commitment for 2007-2020.

FIGURE 4-2
FREQUENCY OF YEARS ENROLLED ACCOUNTS WITH COMPLETED 3-YEAR COMMITMENT (ALL IOUS)



f. Expand PG&E's FastTrack

PG&E proposes to add more customer segments and measures. PG&E's FastTrack application uses pre-approved deemed kW shed calculations for commonly used HVAC and lighting measures. It is limited to non-residential SMB customer. With its simpler application process and ability to cover up to 100 percent of project costs,[5] PG&E proposes to expand FastTrack to increase the number of measures, business sectors and customer segments such as Large Commercial and Industrial (LC&I) customers. This would allow more SMB customers to benefit from the ADR incentive. This expansion may also

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4 CALMAC: "Automated Demand Response Non-Residential Incentive Structure Research Project Report", (Aug. 6, 2020), CALMAC Study ID PGE0452.01, p. 43, Figure 21, <http://www.calmac.org/publications/Automated_Demand_Response_Non-Residential_Incentive_Structure_Research_Project_Report.pdf>, (as of Apr. 21, 2022).

5 Limited to $200/kW of committed and verified load impact.

increase cost effectiveness of the ADR Program since LC&I customers may choose to participate in the ADR program through the FastTrack route rather than the traditional customized calculation route, which takes longer and require more utility and customer resources to implement. The expansion will require an initial investment in contract resources to further develop the FastTrack calculator. PG&E requests authorization of funding of $250,000 to cover its portion of the costs in partnering with SCE on this endeavor.

g. Emergency Demand Response Programs Eligible for Automated Demand Response

PG&E proposes RDRR resources, such as the Base Interruptible Program (BIP), be eligible to receive ADR control incentives. In D.18-11-029,[6] the CPUC ruled "that RDRR resources bid in the California Independent System Operator (CAISO) market through the Auction Pilot should not be eligible to receive ADR control incentives. These resources are reliability resources and, again, the Commission previously stated that reliability programs are rarely dispatched and should not be eligible for these incentives." In Exhibit (PG&E-2) Chapter 3, Section B, PG&E outlined in detail the increased frequency of BIP events in 2020 and the evolving manner in which BIP is now called for system-wide grid emergencies. In light of this, PG&E believes it is an appropriate time to revisit the restriction set out in D.18-11-029 given the number of events for reliability programs in the past funding cycle and the probability of continued higher frequency of events in the future.

Adding BIP as an eligible program for ADR incentives could attract new customers to BIP which has experienced minimal growth and a high rate of attrition in the last few years, as illustrated in Exhibit (PG&E-2) Chapter 3, Section B. ADR incentives would remove a barrier for entry for those who cannot participate in BIP without the use of automation. Since BIP customers are required to reduce load within 30 minutes down to their firm service level, automation can play an

6 D.8-11-029, Decision Resolving Remaining Application Issues for 2018-2022 DR Portfolios and Declining to Authorize Additional DRAM Pilot Solicitations.

integral part in the customer's ability and willingness to participate in the program and reliably drop load. Customers with remote agricultural pumps, irrigation systems or buildings require control technology automation because they are not easily accessible within the 30-minute time frame. PG&E also proposes a 15-minute BIP option in Exhibit (PG&E-2) Chapter 3, Section B; with this option, automation could become even more critical due to the challenges of reducing load with a shortened notification time.

Finally, ADR incentives could help reduce BIP attrition. Customers who receive ADR incentives through a DR program have a high potential of becoming long-term DR participants. A 2020 study authored by Energy Solutions reports on DR engagement from ADR participants: "The data collected across IOUs shows that in general, most incentive recipients are meeting the current three-year DR program enrollment duration requirements…Once an account is enrolled in a DR program after receiving an ADR incentive, they tend to remain enrolled for at least three years, and almost 60 percent of accounts stayed enrolled in DR for five or more years after incentive payment. These results show that the ADR incentive program is a strong driver of sustained engagement with DR programs and that most customers that receive the incentive do become ongoing DR participants."[7] Given short-term reliability needs and significant attrition in BIP, adding BIP as an eligible program for ADR incentives may help reduce BIP attrition moving forward.

As explained in detail in the testimony regarding BIP in Exhibit (PG&E-2) Chapter 3, Section B and the Emergency Reliability Order Instituting Rulemaking (OIR) testimony,[8] PG&E believes that current grid conditions require extraordinary efforts to provide much needed load reduction. Although D.18-11-029 discontinued ADR incentives for

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[7] CALMAC: "Automated Demand Response Non-Residential Incentive Structure Research Project Report", (Aug. 6, 2020), CALMAC Study ID PGE0452.01, p. 43, Figure 21, Automated_Demand_Response_Non-Residential_Incentive_Structure_Research_Project_Report.pdf (calmac.org).

[8] R.20-11-003 PG&E Emergency Reliability OIR Opening Testimony. Chapter 4 (page 4-2 to 4-3)

"RDRR resources bid in the CAISO market through the Auction Pilot",[9] which then impacted BIP, circumstances are very different than in 2018. PG&E believes circumstances warrant revisiting this issue and proposes to add BIP as an eligible DR program for ADR incentives.

h. Discontinue the Residential Deemed Incentive Application

PG&E proposes to discontinue offering ADR incentive to residential customers. Other non-DR programs can be the source of residential ADR technology incentives in the future such as EE, SGIP, IDSM, etc.

i. Budget Proposal

For the 2024 to 2027 Program cycle, PG&E is proposing a budget of \$9,523,479, which is significantly less than the authorized amount of \$20,447,000 in the 2018-2022 DR program cycle, due to the proposed elimination of the residential Deemed Incentive Application process, the discontinuation of DRAM, and efforts to decrease administrative costs for the program. This budget would allow PG&E to continue to increase the number of customers using ADR technologies to respond to DR event signals, which is critical as the CEC and CPUC continue to develop advance dynamic rates, and the CEC's Load Management Standard.

2. Demand Response Emerging Technology Program

a. Program Description

PG&E's DRET Program enables the assessments and studies of new technologies and applications, such as "smart" devices behind customers' meters, new supply side and load modified DR programs design, tools, channels, features to enhance customers' ability to perform in DR and dynamic rates. DRET assessments are designed to explore potential enhancements to the existing DR portfolio and inform the ongoing development of PG&E's DR pilots for future DR programs and dynamic rates. The results and lessons learned from these studies may help facilitate and scale DR integration into the CAISO markets in order to provide different grid services. PG&E provides semi-annual

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[9] D.18-11-029, p. 46.

reports regarding its Emerging Technology projects to the CPUC. These reports summarize each project, the potential benefits of the technology or technique, the activities undertaken as part of the project, and any available data and results. All of the DRET reports are published in the ETCC website[10] and DRET Program website.

In 2018-2021, the DRET Program examined the following topics:

- Developed an ADR incentive for residential EV service equipment;
- Explored using smart speaker, voice automation and mobile app for DR and dynamic rate notification;
- Provided residential rates in a digital format to third parties;
- Assessed a new DR Program design for Agricultural customers;
- Evaluated battery system load reduction shifting capability for DR, time of use (TOU) and hourly price signals;
- Evaluated Smart Controllable Thermostats for DR and TOU optimization;
- Used Heat Pump Water Heater (HPWH) for Load Shifting; and
- Increased adoption of HPWH through the mid-stream channel.

In 2019, PG&E's DRET Program worked with the PG&E Energy Efficiency (EE) team to study program implementation approaches and collect HPWH load shifting data that could be used for future "Water Saver" program implementation. The DRET study was separated into two Phases. Phase 1 was a lab test and Phase 2 was a field test. The study confirmed that the technology enabled electric water heaters to control water heater operations and recorded granular information about water heater energy use, temperature setting, and operation modes. The process for dispatching and monitoring water heaters was fully automated and allowed testing of multiple algorithms. The algorithms clearly reduced peak demand over all five hours in the 4-9 p.m. window while avoiding increases in total daily energy use. The result of this study was used for program design for the "Water Saver" Pilot and

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[10] ETCC, <https://www.etcc-ca.com/reports/automated-demand-response-non-residential-incentive-structure-research-project>, (as of Apr. 22, 2022).

Self-Generation Incentive Program (SGIP) Heat Pump Water Heater (HPWH) incentive.

In 2021, PG&E worked with a battery manufacturer to develop a VPP DRET pilot, which focused on creating residential customer value and potential energy for the IOU and the grid, through controlled behind the meter battery storage serving a single residential premise. Customers were compensated for reduction in charging and export (to home and/or grid) from their battery during event-based dispatches by controlling the customer's enrolled battery in the manufacturer's platform. The report was released in April 2022.

b. Regulatory Background

The DRET Program has been in place since the 2009-2011 program cycle.[11] No major modifications have been made to the program structure since then.

c. Program Proposal

PG&E proposes to continue the DRET Program to evaluate new technologies and applications, which enable our customers to provide service to the grid through DR programs and dynamic rate. PG&E believes it is important to leverage demand side and load management resources to help with the many grid challenges that were identified in Exhibit (PG&E-2) Chapter 2, and it is important to continue to identify new innovative ways and technologies that would increase customer adoption of DR and dynamic rates.

The DRET Program will explore several important topics such as, but not limited to:

<u>Evaluate technologies and processes that can provide benefit to customers on dynamic rates</u> – California is exploring the development of dynamic rates such as real time rates. It is important to develop technologies that would help customers to be successful on an hourly type of dynamic rates and evaluate if and how customers can provide additional resources when enrolling in a DR program at the same time. In addition, the DRET team will collaborate with other Real-Time Pricing

[11] D.09-08-027, pp. 85-89, Section 12.2.

(RTP) Pilots and the CalFlex Hub, which focus on CalFlexHub will support state goals in advancing demand flexibility and decarbonization in buildings by:

- Evaluate capability of building end-use systems load systems to respond to price signals;
- Identify new technology that can deepen response;
- Understand value of price vs carbon signal; and
- Evaluate how to overcome barriers to deployment such as usability, costs, and tech capabilities.

Evaluate DER technologies such as battery and EV for customers in DR and dynamic prices – As customer adoption of storage technologies increases, it is important to develop load shed and shift strategies for different types of storage technologies in different customer segments.

Develop a new process to leverage flexible appliances as grid resources – The CEC is in the process of developing the implementation of SB 49,[12] which requires the CEC to adopt flexible demand appliance standards and labeling requirements to improve grid reliability, minimize electrical grid greenhouse gas (GHG) emissions, and benefit California consumers. The DRET Program will evaluate how best to leverage these flexible appliances (such as DR signal communication requirements and customer education) to help customers enrolled in DR programs and dynamic rates.

Partner with other Emerging Technology Programs – CPUC approved an Emerging Technology Program for EV emerging technologies in its VGI Strategy (D.20-12-029).[13] The DRET Program will collaborate with the new EV Emerging Technology Program and the existing Statewide EE Emerging Technology Program to evaluate integrated technologies. This approach will minimize potential overlap and increase cost benefit for all emerging technology programs.

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12 Senate Bill No. 49, (2019-2020) <https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB49>, (as of Apr. 22, 2022).

13 Decision Concerning Implementation of SB 676 and Vehicle – Grid Integration Strategies, pp. 34-37.

Support ADR and IDSM Program – As stated in the ADR section above, the ADR program will focus more on non-residential deemed measures instead of the calculated methodology in the future. The DRET Program will continue to evaluate the deemed kW potential of different ADR technologies and processes for SMB, LC&I and Agricultural (Ag) customers.

d. Budget Proposal

In the past few years, the DRET Program has demonstrated its importance for identifying new technologies that can help address the capacity shortage in summer of 2022 and 2023. As a result, PG&E is proposing to increase the DRET Program budget from $1.45 million per year on average in the 2018-2022 DR Program cycle to $5.0 million per year annually. The additional DRET funding will allow PG&E to perform larger scale studies and increase the overall number of technologies and processes the program can cover. PG&E will continue to provide DRET Program information and updates to the Commission through the bi-annual report order by D.12-04-045 OP 59.

3. Integrated Demand Side Management Program

In the past, the Commission has articulated a desire to offer IDSM programs and to use EE as a forum in which to do so. D.07-10-032 presented a broad vision for IDSM, ordering IOUs to integrate demand-side customer programs "in a coherent and efficient manner." IOU portfolios that followed included proposals for IDSM programs and approaches. The California EE Strategic Plan (Strategic Plan) recognized the integration of demand-side management (DSM) options, including EE, DR, and distributed generation (DG), as fundamental to achieving California's strategic energy goals.[14] As a result, an IOU and Energy Division Statewide IDSM Task Force was formed in 2010 and has continued coordinating statewide activities that promote the strategies identified in the Strategic Plan and support integration directives in CPUC D.09-09-047.

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[14] California's Long Term Energy Efficiency Strategic Plan (https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/e/5305-eestrategicplan.pdf), September 2008, p. 71, Section 8.

The CPUC repurposed IDSM funds in 2018 as part of D.18-05-041 to focus on the limited integration of EE-DR by providing requirements and general policy principles[15] for Program Administrators (PA) to follow. The CPUC allocated a statewide IDSM budget of $20 million to the non-residential sector and a minimum of $3 million for residential per year.

In the past, PAs had identified that lack of shared funding was a barrier to integration among demand-side programs. D.18-05-041 ordered PAs to set aside funding for specific EE and DR integration objectives. The use of those funds is subject to several requirements and policy principles below:

- Residential IDSM efforts should focus on HVAC technologies and facilitating automatic response to time varying rates;
- Non-residential IDSM efforts should focus on HVAC and lighting control technologies;
- Non-residential customers must enroll in a DR program for at least one year, and up to three years if an incentive is involved; and
- IDSM projects should ensure there is no incremental measure or transaction cost to participate in a DR program after an EE program.

On June 2021, the IOU submitted an IDSM Program detailed guidance document that on September 1, 2021, PG&E clarified that IDSM funds are subject to a number of rigid requirements and policy principles.[16] PG&E believes that these requirements and guidelines were intended to take a measured and conservative step towards integrating EE and DR activities. However, current grid reliability challenges warrant a more aggressive approach. Modifying or eliminating some of these requirements as stated in the IDSM program details document, as PG&E proposed in the pending EE Application,[17] even on a temporary basis, could encourage EE program implementers to add activities into their programs that benefit grid reliability.

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15 D.18-05-041, pp. 36-38.

16 R.20-11-003, PG&E Reliability OIR Phase 2, PG&E Testimony September 1, 2021, pp. 7-9.

17 A.22-02-005: Application of Pacific Gas and Electric Company for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Portfolio Plan.

IDSM Program Guidance Document filed in June 2021[18] outlined the implementation details of the statewide IDSM program. In the document, PG&E and SCE stated that the IDSM program should support broader DER integration efforts such as DR+EV or DR+DG. Such expansion would allow PG&E to introduce new ideas and pilots that increase collaboration between DR and other clean energy programs such as the SGIP, EV Charge Network Program and other VGI Pilots. The IOUs also filed a Tier 2 Advice Letter 6520-E on March 7, 2022, to indicate how PG&E plans to implement the IDSM Program based on the IDSM Program Guidance Document.

The IDSM funds are critical to encourage BTM technology vendors to promote IDSM technologies and DR programs when engaging their customers on opportunities. These opportunities would include customers leveraging their BTM technologies for load management. In addition to increase adoption of technologies that can help customers with TOU, PG&E would leverage the IDSM funds to evaluate a pay for load shape[19] incentive structure that can complement the customers' existing TOU rate.

The existing IDSM Program was approved for eight years from 2018 to 2025. PG&E believes IDSM funds should continue to be authorized in 2026-2027. On February 15, 2022, PG&E filed the PG&E's EE Application and Testimony for its 2024-2031 Strategic Business plan and 2024-2027 Portfolio Plan, A.22-02-005. The 2026-2027 IDSM program funding was requested in the testimony of this EE application, requesting a budget of $9 million per year to fund its IDSM efforts. If the IDSM program is approved in A 22-02-005 , PG&E will continue to recover part of the IDSM funds from the DR Expenditure Balancing Account through 2027. The DR Team will continue to work with the EE team to include the IDSM Program budget on the Energy Efficiency Annual Budget Advice Letter.

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18 Document titled "Limited EE+DR Integrated Demand Side Management (IDSM)" jointly shared by the IOUs' IDSM teams with the CPUC staff via email on June 9, 2021.

19 Final Report of the CPUC's Working Group on Load Shift (Jan. 31, 2019), p. 9, https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report.pdf (as of Apr. 22, 2022) .

C. 2024-2027 Pilot Activities

1. Smart Panel Pilot

a. Problem Statement

The energy infrastructure is going through dramatic transformation as the State continues to pursue aggressive policies to combat climate change. Policies such as SB 350 [20] – Clean Energy and Pollution Reduction Act—once implemented, will unquestionably transform how the grid operates, and in essence change how customers use electricity and interact with their load serving entity (LSE), utility distribution company (UDC), and third parties. These changes should make the grid more efficient, boosting reliability and lowering costs.

PG&E is interested in evaluating the potential of residential smart electrical panels, primarily how customers would interact with a technology that controls their entire home's electric usage. In an electrified world, having centralized control provides the customer with more options on so many different aspects including bill savings. Customers would interact with smart electrical panel's mobile application and enter the amount they want to pay for their electric bill for the month or other time interval. Smart electrical panels can orchestrate and schedule based off what the customer chooses as their essential and non-essential loads. That same approach used for bill savings and resiliency, can then be used for DR participation. The DR program design best suited for a technology like smart electrical panels is demand limiting. Demand limiting with a technology that can orchestrate with the customer in control may be the pathway to a firmer and flexible response, which is needed to manage and to coordinate with and among the LSE, UDC, and third parties to better combat climate change.

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[20] The Clean Energy and Pollution Reduction Act (SB 350) established clean energy, clean air, and GHG reduction goals, including reducing GHG to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050.

b. How the Pilot Will Address a Demand Response Goal or Strategy

The greatest challenge for DR today continues to be the predictability, availability and firmness of the response coming from customers participating directly with an IOU or through a third-party aggregator. The DR Issues and Performance 2021 report by the Department of Market Monitoring stated, "About one-third of the resource adequacy requirements met by DR capacity were not available or directly accessible to the Independent System Operator (ISO) in peak net load hours on days where the ISO issued Flex Alerts and/or system warnings."[21] This challenge compounded with the transition to a future decarbonized grid creates uncertainty on the type of responsive demand may be needed from customers. This uncertainty is predicated on the composition of the delivery system (Transmission and Distribution [T&D]) and type of supply portfolio the state will have (e.g., mostly intermittent or more firm energy delivery). With more questions than answers surrounding the electric grid, this requires thoughtful customer solutions that offer value today and, in the future, providing assistance on bill management (e.g., customers enter how much they can afford per month, maximize savings), offering centralized home control and access to information. Solutions will need to be flexible and dynamic.

The Smart Panel Pilot is evaluating if and how smart electrical panels can offer customers total control of their home, convenience, and choice they need to achieve their energy goals while participating in a DR program. PG&E will be utilizing and testing the customer and grid services captured in Energy Storage Multiple-use Application (MUA)[22] shown below in Table 4-2.

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[21] ISO Demand Response Issues and Performance 2021 (Jan. 12, 2022), p. 2, <http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf> (as of Apr. 22, 2022).

[22] D.18-01-003, p. 10.

TABLE 4-2
MUA SERVICES

Line No.	Domain	Reliability Services[a]	Non-Reliability Services[b]
1	Customer	None	TOU bill management; Demand charge management; Increased self-consumption of on-site generation; Back-up power (resiliency); Supporting customer participation in DR programs
2	Distribution	Distribution capacity deferral; Reliability (back-tie) services; Voltage support; Resiliency/microgrid/islanding	None
3	Transmission	Transmission deferral; Inertia;[c] Primary frequency response;[c] Voltage support;[c] Black start	None
4	Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves; Flexible ramping product	Energy
5	Resource Adequacy	Local capacity; Flexible capacity; System capacity	None

(a) Reliability Services as defined in D.18-01-003 are services which the electric system (transmission or distribution) depends for reliable operation. For example, in the transmission domain reliability services include contingency reserves and any services that are specified for a resource that is procured to avoid or defer a transmission infrastructure upgrade. In contrast, wholesale energy would be a wholesale market service. Note that this distinction does not depend on how the service was procured, i.e., contingency reserves are procured through the wholesale market. What matters is whether the service is critical for the reliable operation of the system.

(b) Non-reliability services as defined in D.18-01-003 are services which the electric system, or an end-use customer, does not depend on for reliable operation and delivery of electricity.

(c) Voltage support, inertia, and primary frequency response have traditionally been obtained as inherent characteristics of conventional generators and are not today procured as distinct services. We include them here as placeholders for services that could be defined and procured in the future by the CAISO.

PG&E anticipates participants in this pilot will take advantage of daily bill savings functions such as conducting TOU optimization and other grid service opportunities as described in Table 4-1 Testing whether customers can meet and deliver stacked grid services on top of retail rate in a reliable and predictable manner will be key. PG&E will develop test cases based upon what grid services may be needed at the commencement of the pilot. Test cases will strive to represent the future customer norms based on the existing issues (wildfire threat, summer reliability capacity shortfall) and any opportunities that are imminent (electrification, EV as transportation and storage).

Below is an example of a possible customer interactive experience with the smart electrical panel's mobile application imminent to a CAISO emergency or distribution event call:

1) Preparation prior to event participation – Using historical data from the past 24 months of electricity usage (e.g., via the "ShareMyData" platform), smart electrical panel vendors will determine the maximum likely uncontrolled peak demand above baseload for each customer.
2) During Flex Alert events, larger electric loads will be "paused" or time-shifted as necessary (based on customer-established priorities that are set with the vendor's mobile app or web) to ensure that the whole-home coincident peak demand doesn't exceed 80 percent of the uncontrolled peak metric for that customer.
3) During any CAISO issued "Energy Emergency Alert (EEA)," the demand/AMP limit thresholds will be reduced further (to 50 percent during CAISO EEA-2 or EEA-3)—for example, a customer with a 100A main breaker whose maximum identified usage is 70A will be limited to 35A of power draw during an EEA-2 emergency (equivalent to approximately 7.7 kW of concurrent power usage).
4) In most cases, customers will be unlikely to notice that their load is being limited, since smart electrical panels will do so by "pausing" non-essential loads as necessary (most commonly, EV charging, water heating, pool pumps, air-conditioning). Customers, in near real-time, will be able to manage which loads are being shed dynamically via vendor's mobile app or web.
5) For day-ahead notice indicating that an event is likely to occur, the smart electrical panels will communicate such via the app, with a recommendation for behavioral action such as: "A Flex Alert Event is scheduled for tomorrow between 4 p.m. and 9 p.m.—your panel will automatically limit electric demand during this period based on your priorities. We recommend you set your thermostat to "pre-cool" your home between 2 p.m. and 4 p.m. to reduce the need for air conditioning during the Flex Alert period."

6) Customers will have the ability to disengage the power limiting functionality during an event (opt-out) but doing so will reduce their incentives.

c. Program Structure

Recruitment

PG&E will work with existing and future customer programs that offer incentives to purchase electrical panel such as SGIP-HPWH or the Fixed Power Solution Pilot[23]. PG&E will market this pilot to customers that have plans to install and upgrade their current electrical panel. PG&E will offer additional incentives to customers interested in joining the Smart Panel Pilot and must install a qualified smart electrical panel.[24]

Customers that have a qualified smart electrical panels installed can participate in the program but will not receive any additional incentives meant to install a qualified smart meter panel.

To ensure fairness, PG&E will recruit up to 500 low income and disadvantage households to this pilot. Aside from working with customer programs, PG&E will collaborate with PG&E's Energy Savings Assistance Program, consult with CPUC's Disadvantaged Communities Advisory Group, and leverage Community Based Organizations on how best to engage.[25]

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23 PG&E Wildfire Mitigation Plan p. 492: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan.page?WT.mc_id=Vanity_wildfiremitigationplan.

24 PG&E will conduct a Request For Information to select smart electrical panels that meet the necessary functional requirements.

25 Approach was done in consideration of Exhibit (PG&E-2) Chapter 1, Section c.6. "Demand Response Support for Environmental and Social Justice" and Exhibit (PG&E-2) Chapter 2, Section H.2 "Disadvantaged Communities Demand Response Pilot".

DR Program Design

Smart Panel Pilot will test a demand limiting approach to ensure that the grid is able to operate reliably when constraints are occurring. Table 4-3 captures the design elements of the pilot program.

TABLE 4-3
SMART PANEL DESIGN ELEMENTS

Line No.	Pilot Elements	Description of Elements
1	Eligibility	Residential bundled and unbundled customers (Customer Choice Aggregator) No dual participation with another grid service program (e.g., CBP, SmartAC^{TM}), any other pilots (e.g., ELRP, percentage of Income Payment Plan pilot) and/or contract (e.g., DRAM)) Participating in RTP is permitted
2	Pilot Operation and Duration	Year-round Event window 24x7 Duration 1 – 8 hours Up to 5 events per month
3	Notification - Trigger	Day-ahead: • Generation – energy price trigger based on CAISO day-ahead market – price trigger to be determined • CAISO EEA-1 (Alert) to EEA-3 (Stage 3) • Distribution – to be determined with distribution planning, engineering, and operations Day-of (real-time): • Generation – energy price trigger based on CAISO real-time 15 min. market – price trigger to be determined • CAISO EEA-1 (Warning) to EEA-3 (Stage 3) Distribution – to be determined with distribution planning, engineering, and operations
4	Incentives	Annual incentive for DR services will be determined based on the grid services customer chooses.

d. Specific Objectives and Goals for the Pilot

Smart Panel Pilot is designed with the customer in mind, considering the challenges they have today and what future challenges emerge. PG&E's objectives are:

- Evaluate and test the efficacy of smart electrical panels assisting customer with their energy priorities; and

- Evaluate and identify integrated approach with other customer programs such as EE Clean Energy Transportation, distributed generation (DG), outage mitigation and SGIP that have similar and overlapping decarbonization goals. Determine opportunities to coordinate with PG&E's Clean Energy Financing Options proposed Finance Platform[26]. Compose how best to offer and present simple solutions to customers including how best to achieve an ideal customer experience to maximize participation.

By utilizing smart electrical panels in this pilot, PG&E plans to achieve the following goals:

- Assist with residential electrification (potential exists to tie this pilot to other electrification initiatives such as home EV charging infrastructure rollout);
- Capture granular end-use data at the circuit level to better understand what loads are on during certain time hours and to identify whether there are any measures that customers are using that can lead to targeted rebates and develop greater partnership with manufacturers to continuously improve technology efficiency and customer experience; and
- Identify whether the smart electrical panels can act as a tool to help with interconnection study and explore if it can function to detect BTM DER.

e. Budget and Timeframe

See Table 4-4 for PG&E's proposed budget over the course of 2024-2027.

TABLE 4-4
2024 - 2027 SMART PANEL BUDGET

Line No.		2024	2025	2026	2027
1	Administrative	$683,703	$808,751	$834,681	$861,524
2	Incentive	2,006,250	2,006,250	2,006,250	2,006,250
3	Total	$2,689,953	$2,815,001	$2,840,931	$2,867,774

26 R.20-08-022 – Pacific Gas and Electric Company's Clean Energy Financing Options Proposal.

f. Standards and Metrics

PG&E will benchmark with relevant pilots by other utilities and program administrators. PG&E will keep track the following as it relates to this pilot:

- Customer satisfaction with the program structure, including ease of customer education, incentive and rebate levels, outreach and tools (e.g., mobile app);
- Customer's ability to achieve multiple value streams (e.g., bill savings, resiliency) using smart electrical panels;
- Smart electrical panel's ability to conduct, orchestrate and deliver multiple grid services (e.g., Generation capacity and energy, distribution deferral);
- Performance of customer response versus forecasted response, specifically, the ability to do demand limiting—was the response firm and predictable; and
- Forecasted versus actual budgets and tracking incentive rebates for smart electrical panels.

g. Methodologies to Test the Cost Effectiveness of the Pilot

PG&E believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. Moreover, pilots are generally exempt from the cost-effectiveness evaluation as they are experimental in nature.[27]

However, PG&E believes that evaluating this pilot's cost-effectiveness is important, primarily if the goal is to scale and commercialized this pilot into a program in the future. It is appropriate during the pilot term to conduct impromptu cost-effective calculation in order to enhance which component of the pilot design requires further improvements such as on-going system cost, customer incentives, vendor and third-party cost, grid services and customer and technology load impacts.

[27] 2016 DR Cost Effectiveness Protocols dated July 2016 at p.18.

h. Evaluation, Measurement and Verification Plan

PG&E will work with the DRMEC to evaluate the performance of some aspects of the pilot. PG&E expects that the evaluation will at the very least include the following:

- An evaluation of the efficacy of demand/amperage (AMP) limiting;
- An evaluation of the impact and satisfaction of customers participating specifically achieving their energy goals (e.g., bill savings, electrification); and
- An evaluation of the impact of the number of event calls between wholesale, distribution and how this impacts the customers overall energy schedule (multi-use application).

i. Strategy to Identify and Disseminate Best Practices and Lessons Learned

PG&E will conduct periodic meetings with the Energy Division throughout the pilot period. The meetings will include current work, budgets, and foreseeable next steps to ensure parties are well informed. PG&E will work with the pilot administrator and Energy Division to develop a report containing results of and lessons learned from the pilot to date. A final report will be published after the conclusion of this pilot.

2. Emergency Load Reduction Program Pilot

a. Problem Statement

The State continues to battle the impacts of climate change including devastating wildfires and capacity shortfalls due to extreme summer heat events. The CPUC has conducted an analysis of the need for new resources and found that a range of 2,000 to 3,000 MWs of new supply-side and demand-side resources should help address grid reliability concerns in the most extreme circumstances. With access to additional cost-effective supply may not be achievable on time and with the pending retirement of Diablo Canyon Power Plant on the horizon, it’s critical to have a contingency pilot program that can offer customers and third parties’ access to monetize their incremental load drop and exports without the punitive penalties that tend to turn customers away from participating in grid service programs such as DR.

On November 19, 2020, the Commission initiated Rulemaking (R.) 20-11-003 to establish policies, processes, and rules to ensure reliable electric service in California in the event of an extreme weather event in 2021. On March 26, 2021, the Commission issued D.21-03-056 directing PG&E, SCE, and San Diego Gas & Electric Company (collectively "the IOUs") to take actions to prepare for potential extreme weather in the summers of 2021 and 2022.

On July 30, 2021, Governor Newsom signed an emergency proclamation to "free up energy supply to meet demand during extreme heat events and wildfires that are becoming more intense and to expedite deployment of clean energy resources this year and next year." In the Governor's July 30, 2021, Emergency Proclamation, all energy agencies, including the Commission, were directed to act immediately to achieve energy stability during this emergency. In response to the Governor's Emergency Proclamation, on August 2, 2021, the assigned Administrative Law Judge sent a ruling to parties in R.20-11-003 initiating Phase 2 of this rulemaking. After receiving testimony, briefing, and comments on the Phase 2 proposed decision from the parties, on December 6, 2021, the Commission issued the D.21-12-015, which ordered the IOUs to take additional actions to prepare for potential extreme weather in the summers of 2022 and 2023. D.21-03-056 and D.21-12-015 authorized the ELRP for five-years, 2021-2025.

b. How the Pilot Will Address a Demand Response Goal or Strategy

Per the Governor's July 30, 2021, Emergency Proclamation[28]:

> The California Public Utilities Commission is requested to exercise its powers to expedite Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of demand

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28 Governor Newsom Signs Emergency Proclamation to Expedite Clean Energy Projects and Relieve Demand on the Electric Grid During Extreme Weather Events This Summer as Client Crisis Threatens Western States, (July 30, 2021) <https://www.gov.ca.gov/2021/07/30/governor-newsom-signs-emergency-proclamation-to-expedite-clean-energy-projects-and-relieve-demand-on-the-electrical-grid-during-extreme-weather-events-this-summer-as-climate-crisis-threatens-western-s/> (as of Apr. 18, 2022). and Governor's Proclamation of a State of Emergency (July 30, 2021), <https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf> (as of Apr. 22, 2022).

> response programs and storage and clean energy projects, to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022.

Capacity and energy shortfall continues to be an issue and to meet the goal of reducing peak and net peak demand, the ELRP Pilot was implemented to address reducing peak and net peak demand during possible extreme weather conditions.

ELRP will allow large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies with the goal of avoiding rotating outages.

PG&E also views the ELRP pilot as a test bed for the development of nascent, grid service use cases—including the allowance of energy export, device-level submetering[29] and the role of PG&E as an aggregator enabling third party service providers as well as third-party aggregators—through operational experience gained through implementation of the ELRP. The scope of interactions necessary between PG&E, third-party aggregators and customers to support these nascent use cases is another key learning. These learnings will serve as key inputs to the development of a comprehensive residential load management strategy which includes serving both reliability and non-reliability purposes for next DR program cycle.

c. Program Structure

PG&E requests continuation of the ELRP for 2024-2025 as authorized in D.21-03-056 and D.21-12-01 and proposes the continuation of the ELRP from 2026-2027. PG&E will continue to utilize the annual Tier 2 AL filing to evolve the pilot based on learnings. The current structure of ELRP consists of 8 sub-groups:

- Non-residential
  - Sub-Group A.1. – Non-Residential Customers;
  - Sub-Group A.2. – Non-Residential Aggregators; and

29 Upon CPUC adoption of submetering protocol and requirements, customers will be required to meet all applicable standards, per D.21-12-015, p. 169, OP 27.

  - Sub-Group A.3. – Rule 21 Exporting DERs.
- Non-residential or Residential Aggregations
  - Sub-Group A.4. – VPP Aggregators; and
  - Sub-Group A.5. – EV and VGI.
- Residential
  - Sub-Group A.6. – Residential Customers.
- Market Integrated
  - Sub-Group B.1 – Third-party DR Provider; and
  - Sub-Group B.2 – CBP Aggregators.

PG&E's implementation of the ELRP in the Summer of 2021 proved to be successful in terms of increasing the amount of participating DR capacity in PG&E's DR portfolio. The addition of the ELRP contributed to the increase in the DR portfolio's capacity which is evidence of the attractiveness of the ELRP to customers given its voluntary nature. As such, PG&E proposes to retain the ELRP.

PG&E proposes to remove all minimum dispatch requirements for group A.2 and A.4/A.5 (as outlined in D.21-12-015 Attachment 2, pages 4-6), as this is inconsistent with the primary objective of providing emergency load reduction.

d. Enablement of New Technologies

The ELRP pilot continues to provide new pathways for exploring integrating emergency demand side products and technologies. Under the ELRP A.4 VPP and A.5 EV and VGI, PG&E will be allowing for an expansive orchestrating and portfolio potentially utilizing battery storage, Solar Generation, EVs, Vehicle to Grid integration, and incremental load reduction (ILR). Results of the ELRP pilot will help PG&E and the Commission assess the benefits of emergency programs and, in addition, provide an in-depth understanding of the benefits of technologies, like energy storage and EVs.

e. Specific Objectives and Goals for the Pilot

PG&E is committed to supporting emergency grid needs and investigating technologies to best serve DR needs. The objectives of the ELRP pilot are:

- Determine drivers for market participants to subscribe to emergency DR program and operational program designs to encourage market participation;
- Determine technical feasibility to dispatch DR resources;
- Review opportunities to meet future requirements for DR RA resources and the CAISO must-offer obligation;
- Investigate how to operationalize and automate the interactions between the CAISO for out of market emergency programs as well as determining how to make this information more readily available to transmission and distribution operations personnel; and
- Develop a method for dispatching available DR resources based on grid operational needs to provide maximum benefit while accounting for customer performance and technological limitations.

PG&E understands ELRP is still under development as a pilot and from it will develop synergies in potentially streamlining and consolidating the customer offerings such as, evaluating the consolidation of sub-group A2, A4, A5, and A6 to support the goal of developing future residential cost-effective DR programs. As previously stated, we will continue to utilize the annual CPUC Tier 2 AL filing process to evolve the pilot based on the learnings experienced during ELRP's operational season. Similarly for non-residential customers, we will be looking at utilizing A1-A5 for future program design.

f. Budget and Timeframe

PG&E's request for budget for ELRP through 2027 with 2026-2027 being incremental to previously approved decision D.21-12-015 for the pilot to run through 2025. All non-A.6 and A.5 ELRP sub-group funding was approved through 2025 with years 2023-2025 in D.21-03-056, subject to revision in this DR application. PG&E proposes funding for 2024-2025 for the ELRP A.6 residential sub-group as under D.21-12-015, it was approved as a 4-year pilot[30] but budget was only

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[30] D.21-12-015, p. 57, "We adopt a four-year Residential ELRP pilot in which bundled and unbundled residential customers of an IOU are eligible to enroll in ELRP by opting-in to participate.".

approved through 2023. The following funding is hereby requested to fund the ELRP pilot through the end of this application period of 2027.

TABLE 4-5
2024-2027 ELRP BUDGET

Line No.		2024	2025	2026	2027
1	Administrative	$12,012,407	$12,267,621	$12,531,819	$12,805,316
2	Incentive	94,000,000	94,000,000	94,000,000	94,000,000
3	Total	$106,012,407	$106,267,621	$106,531,819	$106,805,316
4	(Rounded)	$106.0 million	$106.2 million	$106.5 million	$106.8 million

As directed by D.21-12-015, in 2022, PG&E was required to implement changes to the existing ELRP Group A.1 through A.4 and implement new subgroup A.5 for EV and VGI Aggregator and A.6 for Residential customers.

g. Standards and Metrics

PG&E will benchmark relevant programs by other utilities and program administrators. PG&E will keep track of the following as it relates to this pilot:

- Third-party and customer satisfaction with the program structure;
- Performance (in MWs) of DR resources compared against nominations and forecasted response;
- Develop proxy cost effective calculation for the pilot;
- Forecasted versus actual budgets;
- ILR/Export/Device Level discharge, by interval; and
- Number and duration of events partitioned between CAISO and Utility calls.

As the ELRP Pilot proceeds and additional design elements are added or removed, new standards and metrics may be developed, and the ones proposed herein may no longer be relevant. Any changes to the standards and metrics will be communicated with Energy Division as part of the annual ELRP Tier 2 Advice filing.

h. Methodologies to Test the Cost Effectiveness of the Pilot

PG&E believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. Moreover, pilots are generally exempt from the cost-effectiveness evaluation as they are experimental in nature.[31]

However, PG&E believes that evaluating the pilot's cost-effectiveness is important, primarily if the goal is to scale and commercialized ELRP into a program in the future. It is appropriate during the pilot term to conduct impromptu cost-effective calculations in order to enhance which component of the pilot design requires further improvements such as on-going system cost, customer incentives, vendor and third-party cost, grid services and customer and technology load impacts.

i. Evaluation, Measurement and Verification Plan

PG&E will work with the DRMEC to prepare and conduct a plan to evaluate the performance of some aspects of the ELRP pilot. PG&E expects that the evaluation will include, but not be limited to the following:

- An evaluation of any forecasting and baseline tools developed or used as part of this pilot;
- An evaluation of the impact and satisfaction of DR resource owners participating;
- An evaluation of the impact of the number of calls between CAISO and PG&E; and
- Study and further evaluation of the technologies used to facilitate response by aggregated VPP portfolios, e.g. sub-group A.4. and A.5.

j. Strategy to Identify and Disseminate Best Practices and Lessons Learned

PG&E will continue to report ELRP forecasts and conduct periodic meetings with the Energy Division throughout the pilot period. The meetings will include current work, budgets, and foreseeable next steps to ensure parties are well informed. PG&E will work with the pilot administrator and DRMEC to develop a report containing results of and

[31] 2016 Demand Response Cost Effectiveness Protocols dated July 2016 at p. 18.

lessons learned from the pilot to date. This report will be published and be made publicly available on a designated public internet site by PG&E and/or DRMEC.

3. Agricultural Demand Response Pilot

a. Problem Statement

An opportunity exists to grow DR participation and load reduction among businesses in the agricultural sector by developing an agricultural specific DR program. The agricultural sector represents a substantial portion of peak load, about 1.6 gigawatt during summer peak hours of 4p.m. to 9p.m., or 9 percent of net system load on peak days. This sector is characterized by load patterns which differ from industrial, commercial, and residential loads. Specifically, agricultural customers tend to have intermittent loads associated with seasonal irrigation pumping and process loads that may or may not be available for load reduction on system peak days.

Existing DR programs are not always a good fit for agricultural customers. CBP can present challenges for agricultural participation because program rules require nominated load reduction which assumes load is present for reduction on event days. BIP has minimum capacity requirements and excess energy charge costs that may not be suited for all agricultural customers; moreover, the program is not eligible for ADR incentives which some agricultural customers leverage. A firm service level model, which essentially defines performance around the ability to stay below a certain load level, is much better suited to the intermittent loads of the agricultural sector. As such, PG&E has undertaken a research study to inform a DR program designed for agricultural customers, built around this type of firm service level model.

b. How the Pilot Will Address a Demand Response Goal or Strategy

The objective of the Agricultural DR pilot is to increase DR participation and load reduction among agricultural customers who make up a substantial portion of peak load. In 2021, PG&E worked closely with Demand Side Analytics and Energy Solutions to implement a research study through the DRET Program.[32] The study was designed to answer which program configuration (e.g., participation terms, incentive levels, and dispatch rules) for agricultural customers would produce the most DR value. The research study considered two lenses: a quantitative lens which assessed design cost-effectiveness based on results from a conjoint choice model survey and qualitative lens which included interviews with market actors and benchmarking assessment of agricultural DR programs at other utilities.

For the quantitative research, the research team analyzed loads for all PG&E agricultural customers and conducted a conjoint model survey of 160 PG&E agricultural customers. Survey participants made choices between different program designs that presented tradeoffs between incentive levels, participation terms (e.g., penalties and capacity payment), dispatch frequency, event duration, and notification timeframe. They were also asked what portion of their peak load they could drop during the event; load drop was based on the specific respondent's peak load and the percent the respondent said could be dropped in the context of a DR program design. Unlike regular surveys, conjoint studies are designed to quantify the relationship between customer choices and the attributes of the program design, thus identifying the program design elements that matter most to customers. Stronger preferences will drive more of the enrollment likelihood than others. The study revealed that customers place more weight on penalty free options than all other attributes, including incentive levels. Preferences within other attributes (incentive level or expected event duration) were somewhat less pronounced. Importantly, all designs were characterized to respondents as including performance pricing relative to a firm service level.

These choice models were then incorporated into a program design simulation tool, which also incorporated the expected benefits (avoided generation capacity, reflecting Effective Load Carrying Capability

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32 ETCC Agricultural Demand Response Study, Project Number ET21PGE1290, <https://www.etcc-ca.com/reports/agricultural-demand-response-study> (as of Apr. 22, 2022).

derating for dispatch availability, manual dispatch vs automated, etc.) and expected costs (performance payments, administrative, upfront technology costs, ongoing automation costs, etc.) for each respondent and each product design. This enabled calculation of expected net benefits for each program design. The program design simulation tool was used to identify a program design which is expected to maximize net benefits.

For the qualitative approach, the research conducted benchmarking research on agricultural DR programs offered in the US as well as agricultural control technologies available for ADR. The team also conducted interviews with key stakeholders throughout the study, including collecting market input on proposed agricultural program designs. The findings from the interviews were incorporated into the recommended program design.

There was strong alignment between the quantitative and qualitative research in terms of program design elements likely to be preferred by the agricultural customers and yield a successful program. A recommended program design was drafted using key results from the study. The next step will be to pilot test a program design in the field which closely resembles the recommended pilot design.

c. Program Structure

The proposed pilot design considers multiple research efforts from the DRET study, including customer preferences from the conjoint choice survey, an analysis of customer loads for agricultural customers, a cost-effectiveness analysis, benchmarking of agricultural DR programs at other utilities, interviews with aggregators and a technology provider, and research into agricultural technology and industry reports on agricultural DR. PG&E will use the pilot to test and modify the proposed program design elements to determine an optimal agricultural program design.

TABLE 4-6
PROPOSED PILOT DESIGN

Line No.	Product Option	Performance	Capacity + Penalty
1	Expected event frequency	12/year	12/year
2	Event duration	4 hours	4 hours
3	Notification	Day-ahead	Day-ahead
4	Participation terms	Performance only	Performance + low penalty
5	Capacity payment ($/kW-yr)	N/A	$50
6	Performance price ($/kilowatt-hour (kWh))	$0.94	N/A
7	Penalty ($/kWh)	N/A	$1.56

a) **Participation Terms:** The results of the conjoint survey revealed that a performance-only design is preferred three to five-fold over a design with penalties. Given the expected boost to enrollments, a performance-only design is therefore expected to yield greater MW load reduction and greater net benefits than a design with a penalty, even after factoring in assumptions for lower performance with a performance-only design. Therefore, PG&E's pilot design includes a performance only product offering. Given stakeholder feedback, a second product offering with a capacity payment and low penalty will also be offered to customers. The second product offering is explained below.

b) **Two-Product Offering:** There is reasonable alignment among customers and third-party aggregators regarding preferences for dispatch frequency and duration, notification time, and participation payment levels. However, preferences diverge between customers and aggregators when it comes to participation terms. Customers strongly prefer a performance-only design while aggregators and technology providers strongly prefer a design which couples a guaranteed capacity payment with penalties. Therefore, PG&E's pilot design includes a secondary product offering with a capacity payment and low penalty. A side-by-side field test will help assess the comparative values of both offerings.

c) **Event Duration and Expected Event Frequency:** Study results indicated that event duration and event frequency are not the primary drivers of enrollment likelihood. Given that longer and more frequent events also deliver more avoided capacity value, moderate event duration (4 hour) and frequency (12 events) balance net benefits with dispatch flexibility.

d) **Event Notification:** The pilot design will include a day-ahead notification. Event notification is a key driver of enrollment likelihood, with a one day ahead (24 hour) notification strongly preferred by customers to a day-of (30 minutes) notification.

e) **Compensation Structure:** Customer performance will be evaluated based on an ability to remain at or below a predetermined firm service level. The exact methodology to calculate incentives and incentive amounts will be tested over the course of the pilot.

f) **Event Triggers:** The pilot design may test both economic and reliability triggers. Event results will be used to identify which event triggers are optimal and feasibility of market integration.

g) **Eligibility and Enrollment:** Customers must be on an agricultural TOU rate schedule. PG&E will be determining which agricultural TOU rate schedules are appropriate. Customers can enroll directly with PG&E or through a third-party aggregator.

h) **Automation Incentives:** Customers participating in the pilot should be eligible for ADR incentives. PG&E will evaluate the results of customers using automation compared to those that manually provide load reduction.

i) **Program administration:** PG&E will contract with third-party vendors to implement the pilot. The third-party vendors will be responsible for customer recruitment, event season operations, post-event settlements, and program evaluation.

j) **Program marketing, outreach, and education:** Customer outreach and recruitment will include coordination with PG&E Customer Relationship Managers in the Agricultural Sector, leveraging relationships with existing trade allies or aggregators that are involved in the DR agricultural sector, and creating collateral for agricultural customers to provide education about the pilot and address any known concerns over DR programs.

k) **Estimated MW Load Impact:** Study results estimate the potential for 17.5 MWs during peak hours under a fully ramped up proposed pilot design.

d. Specific Objectives and Goals for the Pilot

The objectives of the Agricultural DR pilot are to:

- Determine if proposed designs can increase agricultural DR participation and load reduction during peak hours;
- Test design parameters to optimize peak load drop and net benefits;
- Determine reliability of load reduction by comparing forecasted versus actual load reduction provided; and
- Assess if program designs would be cost-effective.

e. Budget and Timeframe

PG&E requests the following funds for a 4-year Agricultural DR pilot. Administration expenses include costs for PG&E labor including program management, customer recruitment, and marketing efforts. Contract expenses include estimated costs for PG&E's third-party pilot implementor. Automation incentives will be funded through PG&E's ADR program and are not included below. The field test for the pilot would be conducted from 2024 to 2027. PG&E will assess if the pilot should be continued or if pilot design modifications are necessary after two years and submit a Tier 1 Advice Letter.

TABLE 4-7
BUDGET FOR AGRICULTURAL PILOT

Line No.		2024	2025	206	2027
1	Administration	$186,343	$192,902	$199,693	$206,722
2	Incentive	600,000	600,000	600,000	600,000
3	Contract	400,000	400,000	400,000	400,000
4	Total	$1,186,343	$1,192,902	$1,199,693	$1,206,722

f. Standards and Metrics

PG&E will keep track of the following as part of its program standards and metrics:

- Forecasted versus actual budgets;
- Forecasted versus actual load reduction, by interval;
- Forecasted versus actual enrollment, by customer count and estimated MWs; and
- Customer and aggregator satisfaction and feedback.

The above metrics will help inform the results of the below program design goals:

- Increase in the number of agricultural DR participants;
- Greater load reduction per SAID than agricultural participants in existing DR programs;
- Reliable load reduction (the program can deliver the amount of load reduction that is forecasted);
- Higher customer and aggregator satisfaction than agricultural participants in existing DR programs; and
- Cost-effectiveness of a full program would remain the same or better than existing DR programs offered to agricultural participants.

g. Methodologies to Test the Cost-Effectiveness of the Pilot

PG&E believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. Moreover, pilots are generally exempt from the cost-effectiveness evaluation as they are experimental in nature.[33]

However, PG&E believes that evaluating the pilot's cost-effectiveness is important, primarily if the goal is to scale and commercialize the agricultural pilot into a program in the future. It is appropriate during the pilot term to conduct impromptu cost-effective calculation in order to enhance which component of the pilot design requires further improvements such as on-going system cost, customer

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[33] 2016 DR Cost Effectiveness Protocols, (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/cost-effectiveness/2016-dr-cost-effectiveness-protocols---clean.docx) dated July 2016 at p. 18.

incentives, vendor and third-party cost, grid services and customer and technology load impacts.

h. **Evaluation, Measurement and Verification Plan**

PG&E will prepare and conduct a plan to evaluate the performance of the AG DR Study. PG&E expects that the evaluation will include, but not be limited to, the following:

- Evaluation of DR incentive structures;
- Evaluation of triggers to call a curtailment event;
- Evaluation of DR customer forecasting and event measurement tools that may be developed or used as part of this pilot; and
- Evaluation of the impact and satisfaction of participating DR customers

i. **Strategy to Identify and Disseminate Best Practices and Lessons Learned**

PG&E will use learnings from the pilot to inform its position on how an agricultural DR program could be implemented and potentially integrated into the CAISO market. PG&E will work with the pilot administrator to develop an annual report containing results of and lessons learned from the pilot. This report will be published and be made publicly available on a designated public internet site by PG&E. This information will also be used to assess if the pilot should be continued or if any program modifications are necessary.

D. Load Management Activities

1. Regulatory Background

On October 21, 2019, the CEC opened Docket 19-OIR-01 commencing the Load Management Rulemaking. This rulemaking was established due in part to SB 100[34] (SB 100) and Executive Order B-48-18[35] committing to a

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34 Statute directs the CEC, CPUC, and California Air Resources Board to plan for a 100 percent zero-carbon grid. Legislation states:

> It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045.

35 Policy calls for speeding the transition to zero emission vehicles and have at least 250,000 EV-charging stations by 2025, and 5 million zero-emission vehicles by 2030.

carbon free electric grid. More recently, Assembly Bill 3232 (AB 3232) and SB 49 (SB 49) emphasized the need for increased demand flexibility to help enable the rapid penetration of intermittent resources. The Load Management Rulemaking authorized the CEC to consider refinements to tariffs, technologies, and other measures to effectively grow Load Management tools and approaches to support future carbon free grid. On January 14, 2020, the CEC hosted a workshop introducing the 2020 Load Management Rulemaking, under the Warren-Alquist Act of 1974, which described several goals: (a) establishing cost-effective utility programs for improved system efficiency, (b) lessening or delaying the need for new electrical capacity, (c) reducing fuel consumption, and (d) lowering the long-term economic and environmental costs of meeting the State's needs. CEC held four additional workshops from March 2020 to February 2022 which focused on various components of Load Management:

- March 3, 2020 – Draft tariff standard amendments;
- April 12, 2021 – Draft Load Management Standards staff report;
- August 27, 2021 – Market Informed Demand Automation Server (MIDAS);
- February 8, 2022 – Proposed Action and Public Hearing; and
- April 5, 2022 – CEC released 15-day public comment document incorporating new Load Management Standards language

CEC Commissioners will consider adopting proposed regulations May 2022.

2. Proposal

PG&E generally agrees with and supports the CEC's Load Management endeavors. Enablement and access to digitized information such as electricity prices and GHG signals are the opportunities that may lead to unlocking value to customers, creating a cleaner supply portfolio, and providing the state with load curves that would support a reliable and balanced California grid. There are, however, practical steps to realize this goal, but the initiative's first goal is a reasonable timely approval by the CEC on Load Management. PG&E recognizes that the proposed Load Management Standards regulations and its approval will not occur until after the submission of this application. Acknowledging that changes or possible denial of proposed regulations may be conceivable, PG&E believes the work and partnership with the CEC supporting customers, third-party service providers, and manufacturers with Load Management signals is too critical to pause.

To that end, PG&E is proposing the following budget and activities, not limited to, supporting CEC Load Management Standards, including support of MIDAS:

- Development and enhancement of existing or new systems (e.g., such as PG&E's ShareMyData) to support the on-going development of a standard platform for delivering customer rate identification number and ensuring compliance with state and CPUC privacy requirements protecting customer specific information;
- Support of the development of a machine-readable digital code for customers to link prices-to-devices and approach for providing digital codes to customers and third parties supporting customers;
- Development of customer bill presentment providing education, explanation of time-varying rates, and presentment of the customer rate identification number;
- Replacement of existing manual rate sheet and development of an automated streamlined process from utility to CEC updating rate sheets;
- Support of on-going operations and maintenance (O&M) including maintaining accurate PG&E rates and timely transmission to CEC's MIDAS portal; and
- Development of education and outreach to educate customers and third parties on Load Management

PG&E is proposing $8 million dollars covering years 2024-2027. The proposed budget is an estimate based on the current CEC proposed Load Management Standard requirements and are subject to change. PG&E is forecasting $5 million would go towards enhancing existing or new systems and on-going O&M support. The remaining $3 million would go towards development of a team to support administration, policy development, project management and Marketing, Education and Outreach.[36] Upon approval of the CEC Load Management and any initiatives that support Load Management Standards such as SB 49 Demand Flexibility, PG&E will re-assess cost estimates, develop project scope and generate an implementation timeline. To be transparent with work scope and spending, PG&E will file a Tier 2 AL describing and outlining the work and amount needed to comply.

E. Conclusion

PG&E understands that the next four years (2024-2027) bring uncertainties on how the grid will evolve operationally as the state continues its pursuit of a clean decarbonized grid. Activities proposed in this chapter focuses on providing assistance to the grid by evaluating customer technology solutions and program offerings that is designed with growth and reliable responses in mind:

a) Unlocking new demand side opportunities for greater integrated approach utilizing the IDSM, and Auto-DR program;
b) Enhancing and improving customer experience and testing new customer technologies by leveraging the DRET Program;
c) Imagining the future customer solution with the smart electrical panels;
d) Attracting all customers by offering an emergency program pilot that is pushing the boundaries by enabling and incentivizing customer exports, exploration of sub-metering opportunities, and attracting new market actors (VPP and VGI providers) with ELRP;
e) Supporting the development and evaluation of DR design to engage more agricultural customers with the Ag DR Pilot; and
f) Supporting the state and CEC's Load Management efforts on further enabling demand flexibility with PG&E's Load Management Activity.

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36 The proposed budget does not include the development and implementation required under the CEC Load Management Standard for dynamic rates approved by the rate setting authority.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

THIRD-PARTY DEMAND RESPONSE

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THIRD-PARTY DEMAND RESPONSE

A. Introduction

Under Pacific Gas and Electric Company's (PG&E) Electric Rule 24 tariff, third-party Demand Response Providers (DRP) can enroll bundled and unbundled (i.e., Community Choice Aggregators [CCA]/Energy Service Providers [ESP]) electric retail customers for direct participation in the California Independent System Operator's (CAISO) wholesale electric market. Today such enrollments leverage the CAISO's Proxy Demand Response model,[1] which is one of the models utilized by third-party DRPs participating in the Demand Response Auction Mechanism (DRAM), as well as those outside of DRAM.

While the long-term aspects of DRAM are unclear at this time, PG&E anticipates growth in the number of Demand Response (DR) participants administered by third-party DRPs.[2] Such third-party DRP administered DR programs can include contracts directly with PG&E (e.g., DRAM) and those supporting unbundled energy providers (i.e. CCAs/ESPs). As it relates specifically to third-party DRP contracts with PG&E, other than DRAM, which is currently in the process of completing the 2023 RFO,[3] PG&E can enter into DR bilateral contracts for resource needs. As an example, the California Public Utilities Commission (CPUC or Commission) in the Reliability Rulemaking (Rulemaking (R.) 20-11-003) requested the utilities to engage in DR bilateral contracting.[4]

As discussed in other parts of this testimony, third-party DR is expected to experience rapid and significant growth during the 2023-2027 period because of projected enrollments of customers by third-party DRPs, including participation

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1 Previously, DRAM could participate using the CAISO's Reliability Demand Response Resource (RDRR), which is the mechanism that PG&E's BIP tariff operates under. RDRR's ability to participate in DRAM was eliminated via D.19-07-009.

2 Bridge Funding (2023) Exhibit (PG&E-1) Chapter 2 and Exhibit (PG&E-2) Chapter 6, Section C of the 2024-2027 portion of the application.

3 The Tier 1 Advice Letter (AL) for requesting approval of the 2023 DRAM RFO is scheduled to be filed on May 31, 2022.

4 D.21-12-015, pp. 164-165, Ordering Paragraph (OP) 13.

in the CAISO market. In response, PG&E identified enhancements to Information Technology systems, including the ShareMyData platform, to support the expected increase in participation levels.

B. Demand Response Auction Mechanism

1. Background

The original vision for DRAM was established in the 2013 Demand Response Rulemaking (R.13-09-011) with a two-phased pilot called for by Decision (D.) 14-12-024 covering 2016 and 2017. This pilot was envisioned as a new supply-side DR approach for third-parties and was intended to encourage new participants in the DR market (both DR providers and customers). DRAM was viewed by certain parties as providing a more flexible alternative for CAISO market integration as compared to the Aggregator Managed Portfolio (AMP)[5] contracts at the time.[6]

Since 2016, DRAM solicitations have occurred with ongoing refinements undertaken through workshops and Advice Letters, resulting in a number of Commission decisions and resolutions.[7] The most recent DRAM Request for Offer (RFO) solicitation occurred in the first half of 2022 for 2023 calendar year resources. Selected offers are to be filed via a Tier 1 AL with the Commission on May 31, 2022.[8] At this point in time, no Commission determination has been made regarding the post-2023 period.

2. Discussion

a. Performance

The investor-owned utilities were ordered in a 2019 Commission decision[9] to engage a third-party evaluator to assess the performance of

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5 PG&E closed its AMP tariff at the end of 2017.

6 D.14-12-024, p. 63, Section 5.3.1.

7 D.16-06-029, D.17-10-017, D.18-11-029, D.19-07-009, D.19-09-041, and D.19-12-040; Resolution (Res.) E-4817 (Jan. 25, 2017) and Res.E-5110 (Dec. 18, 2020).

8 A joint utility Advice Filing submitted on September 15, 2021, by Southern California Edison Company (SCE) included the schedule for the 2023 RFO. (SCE's AL 4588-E, PG&E AL 6328-E, and San Diego Gas & Electric Company AL 3848-E).

9 D.19-07-009, pp. 112-113, OP 16, p. 15 and p. 32. D.19-07-009, p. 78 specified that the draft evaluation report was to be released no later than September 1, 2021, and a final evaluation report was to be issued no later than December 1, 2021.

the DRAM. The original release of the evaluation report by the end of 2021 was subsequently delayed until April 2022.[10] Thereafter, the CPUC provided an additional extension until May 23, 2022,[11] beyond the filing date of PG&E's 2023-2027 DR Application. While PG&E's own experience with its DRAM contracts and DRAM Sellers informs the recommendations within this chapter of the testimony, it reserves the right to update its Testimony based on the release of the final DRAM evaluation report in late May.

PG&E's experience has shown that the DRAM Agreement has not substantively improved from the Commission's prior determination that the DRAM pilot had a permissive performance requirement structure and recommended that standards and expectations be raised going forward through increased reporting to improve the visibility into performance.[12] Despite incremental improvements, DRAM has not delivered the reliable Resource Adequacy (RA) capacity that was envisioned.

PG&E believes that the DRAM Agreement does not include provisions that would sufficiently penalize for under or non-delivery of contracted capacity. Specifically, the following weaknesses have been observed with the DRAM Agreement:

- Capacity contracted is not consistently delivered to PG&E in the monthly DRAM Sellers' Supply Plans,[13] and resources on their Supply Plans are not always bid into the CAISO's market in

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10 CPUC's Executive Director letter dated September 30, 2021, granting of the extension requested by SCE per its letter dated August 31, 2021.

11 CPUC's Executive Director letter dated April 1, 2022, granting of the extension requested by Nexant (now known as Resource Innovations) per its letter dated March 25, 2022.

12 D.19-07-009, p. 75, Section 3.9.

13 The Supply Plan is used to demonstrate to the CAISO that a resource is providing RA benefits. See CAISO, Market Participant User Guide, Customer Interface for Resource Adequacy (CIRA) (Rev. July 21, 2021), p. 8, Section 3.3, <https://www.caiso.com/Documents/CIRAUserGuideforMarketParticipants.pdf> (as Apr. 19, 2022).

accordance with the Must Offer Obligation (MOO) requirement.[14] Certain provisions in the DRAM contract do not incentivize the actual delivery of contracted capacity but rather only meeting Qualifying Capacity (QC), which can be less than contracted capacity[15] Therefore, Demonstrated Capacity (DC),[16] on which payments are made deviates from the Contract Quantity; and

- The Undelivered Energy Penalty (Minimum Energy Dispatch Requirements) provision only penalizes based on average QC (in megawatts) for each of the three highest Showing Months on the month-ahead Supply Plans relative to the cumulative energy delivered during the contracted months.[17] Consequently, full performance cannot be assessed until the end of the contract term,[18] which delays the ability to monitor ongoing performance.

b. Load Impact Assessment

PG&E believes the QC assessment process specific to DRAM[19] fundamentally lacks the rigor necessary to consistently measure third-party DR capacity using established standards and calculation methods, particularly when compared to the Load Impact Protocol (LIP) Process, which Utility DR programs undergo annually.[20] The DRAM QC assessment process lacks transparency and allows DRAM Sellers to pick events involving favorable conditions that demonstrate their

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14 The MOO compels RA (capacity) products to bid or self-schedule into the CAISO's market in order to obtain RA credit. The QC can be less than contracted capacity because the DRP's estimation can be less than contracted capacity. Such estimation is not based on the same Load Impact Protocols that utilities use for evaluating their DR programs. Likewise, PG&E may derate the QC based on historical performance.

15 Unlike other RA contracts which have RA replacement requirements and penalties, DRAM contracts do not. Instead, the DRAM provider simply receives a smaller payment (or no payment) based on performance.

16 The DC is a demonstration of the amount of capacity that is delivered.

17 Section 1.7 of the DRAM Pro-forma developed, pursuant to D.19-12-040, pp. 96-97, OP 3, instituted beginning with the 2021 DRAM solicitation.

18 DRAM contracts are generally one calendar year in duration, but can be seasonal in nature (e.g., May-October).

19 D.19-07-009, p. 108, OP 7 and Appendix A, p. 2.

20 D.08-04-050 and D.10-04-006.

resources can perform at certain levels, while the LIP process requires all event data to be provided, including the reference load (or baseline) and the event performance across all hours throughout all event days.

The DRAM QC assessment process does not allow PG&E to understand the persistence of load impacts across multiple event hours or the accuracy of the baselines, and how DRAM Sellers predict their performance, compared to the annual LIP process. The DRAM QC assessment process typically raises many questions that are not readily apparent, e.g., inconsistencies in methodologies and errors with data provided through the process, while the annual LIP process establishes clear protocols, more standardized methods and approaches to determining available QC, and sufficient flexibility to align to a specific DR program's design.

The DRAM QC assessment does not currently capture how customer composition changes in a seller's CAISO registered resources, which can lead to inconsistencies in resource performance over time. However, the annual LIP process requires analysis of impacts across various customer sizes and compositions, and thus enables better estimates for various customer groups.

c. Lack of Robust Market

From a market standpoint, PG&E observes that the number of winning bidders has generally been flat.[21] Moreover, the 10 percent new market entrant set aside has not successfully attracted new bidders in the 2021 and 2022 DRAM RFO and certain prior bidders have not bid into recent solicitations.[22] PG&E supports the Independent Evaluator (IE) recommendation:

> …to assess why interest in DRAM appears to be declining. In particular, the IE [has] question[ed] whether the complexities in the evaluation and selection process, inconsistencies in the application of qualitative or project viability assessments, contract provisions, or

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[21] After 2017 the number of third-party DRPs with DRAM contracts has ranged from four to six through 2022. The 2023 solicitation is not yet final.

[22] Several DRPs that were previously active have not bid since the 2021 calendar year solicitation.

other factors not related to the DRAM process are driving the reduction in bidders and offers submitted.[23]

d. Transparency

Lastly, a significant lack of transparency into the sellers' actions makes it difficult to determine contract compliance and to administer contracts. PG&E has limited visibility into what the seller has bid or scheduled into the CAISO and settled for the same event for what the DRAM Seller has reported to PG&E in the form of DC on the monthly invoice.[24]

3. The Demand Response Auction Mechanism Pilot Flaws Are Difficult to Address

PG&E believes the DRAM pilot cannot be sufficiently refined to address these issues. If the CPUC still has a goal of increasing the amount of third-party DR in the market, a new mechanism is warranted. For the reasons described above in Section 2 of this testimony (Discussion), the existing DRAM Agreement is not appropriate for this kind of product. The lack of transparency that underlies the DRAM Agreement makes it difficult to have adequate oversight to ensure that the seller is capable of and actually providing the resource amounts in the CAISO market.

If the CPUC decides to pursue a permanent DRAM mechanism or a significant extension, then it needs substantial modifications to address these issues through a fresh look at the pilot requirements and foundational elements, such as the following:

- PG&E or a third-party administrator should have full insight and access to the third party's CAISO records. Potentially, a single independent Scheduling Coordinator could serve all DRAM Sellers in a consistent and transparent manner;

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23 Merrimack Energy Group, Inc., 2022 DRAM RFO Final Report of the Independent Evaluator On the Bid Evaluation and Selection Process (May 28, 2021), p. 58, fn. 53.

24 While CAISO settlement data may provide information on accepted bids, it does not provide insight on whether the MOO has been satisfied (i.e., whether bids were made during the Availability Assessment hours).

- Performance and incentive payments should be assessed for each dispatch; the MOO method should be eliminated or modified as it is difficult to verify by the utility; and
- Energy dispatch requirements need to be assessed throughout the delivery period, and not just at the end of the contract term.

4. Cost Effectiveness

While PG&E supports the CPUC's position that a permanent DRAM should be cost-effective,[25] PG&E believes the methodology for measuring the cost-effectiveness for DRAM should be comparable to that applied to utility programs.[26]

C. Third-Party Demand Response Opportunities

PG&E believes there are a number of alternative opportunities for DR providers besides DRAM. These opportunities are available both through the Utilities' bundled customers and/or with unbundled customers served by CCAs/ESPs. To expand on this, with the grid challenges identified in Phases 1 and 2 of the Reliability Order Instituting Rulemaking (OIR) (R.20-11-003), which effectively raised the Planning Reserve Margin to 22.5 percent, DR resources have the ability to participate through a specific call-out for DR bilateral contracting per D.21-12-015, OP 13. Moreover, DR resources have the ability to participate in distribution deferral projects as part of the Distribution Investment Deferral Framework originally established in the Distribution Resource Plan Rulemaking (R.14-08-013). PG&E sees additional opportunities for DR resources either through targeted efforts, such as distribution deferral projects, the Reliability OIR or through broader need-based initiatives handled through the Integrated Resource Planning OIR (R.20-05-003) process.

Besides opportunities through Utility programs, DR resources are able to participate in offerings by CCAs and ESPs. In PG&E's territory alone, there are

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[25] D.19-12-040, p. 41, Section 3.8.

[26] PG&E acknowledges that the current DR Cost-Effectiveness Protocols last updated in July 2016 requires a revisit. Nevertheless, the current methodology used to assess DR cost-effectiveness or any replacement methodology (e.g., Total System Benefit) should apply to both utility and third-party DR programs.

no fewer than 12 CCAs[27] with up to nine CCAs either having an existing DR program or one in development.[28] This is in the context of approximately 60 percent of all PG&E utility distribution customers served by CCAs.[29]

D. Conclusion

PG&E recommends that a permanent DRAM should not be authorized, without significant changes. PG&E believes the current DRAM pilot design is fundamentally flawed. Therefore, it should be revamped altogether, or not continued, and as an alternative, encourage DR resources to participate in need-based procurement, which directs resources to participate in solicitations, including any specific mandate for DR.[30] PG&E believes this is a better path for participation by third-party DR providers in that: (1) it's need based, and (2) allows for DR to compete on a level playing field with other supply resources.

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27 PG&E website, CCA programs within PG&E's service area, <https://www.pge.com/en_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/community-choice-aggregation.page#:~:text=Under%20the%20Community%20Choice%20Aggregation,our%20transmission%20and%20distribution%20system> (as of date Apr. 18, 2022).

28 CALCCA website, Demand Response, <https://cal-cca.org/cca-programs/>, (as of Apr. 18, 2022).

29 Metric as of December 31, 2021.

30 D.21-12-015, pp. 164-165, OP 13.

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CHAPTER 6

DEMAND RESPONSE OPERATIONS

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DEMAND RESPONSE OPERATIONS

A. Introduction

California Public Utilities Commission (CPUC or Commission) Decision (D.) 14-12-024 mandates that event-based Demand Response (DR) programs shall be integrated into the California Independent System Operator (CAISO) market in order to maintain Resource Adequacy (RA) value. Pacific Gas and Electric Company (PG&E) seeks funding in this application to continue operating and enhancing the Demand Response Market Integration (DRMI) Information Technology (IT) platform, cover anticipated vendor costs, and the full-time employees (FTE) needed to operate DR programs and Electric Rule 24 over the 2024-2027 cycle to support their integration in the CAISO markets. Lastly, PG&E does not anticipate the need to modify its billing systems to implement any DR proposals for this cycle.

PG&E is requesting an initial budget in the amount of $33,534,000 to support PG&E DR operations for the period 2024-2027. Additionally, PG&E is requesting $13,916,000 to support Rule 24 program operations for the same time period. Table 6-1 below presents PG&E's annual budget request for 2024-2027.

TABLE 6-1
SUMMARY OF PG&E'S ANNUAL BUDGET REQUESTS FOR PG&E DR OPERATIONS AND RULE 24 PROGRAM OPERATIONS
(MILLIONS OF DOLLARS)

Line No.	Program	2024	2025	2026	2027	Program Total
1	DR Operations	$8.06	$8.27	$8.48	$8.72	$33.53
2	Rule 24 Operations	3.36	3.47	3.59	3.50	13.92
3	Annual Total	$11.42	$11.74	$12.07	$12.22	–

The remainder of this chapter discusses in more detail the components of PG&E's budget requests.

B. Demand Response Operations

The shift towards CAISO market integration under D.14-12-024 necessitated that DR Operations move towards greater technical integration of PG&E systems with external vendor systems; the use of interval and real-time data; and the streamlining of the previously disparate business processes and IT workflows. To effectuate the move towards market integration, PG&E concluded that an over-arching system to manage both market and retail/customer activities was necessary. This pivot from the use of multiple IT platforms and separate systems (some dedicated to market activities and others to retail/customer activities) towards more closely integrated systems provided synergies that enhanced the program and operational management of DR. Accordingly, PG&E also stood up the DRMI IT platform in 2018 to support both activities under one umbrella.

1. Summary of Demand Response Operations Budget Request

D.17-12-003 established two budget sub-categories to track the costs of systems support and other activity necessary for operating PG&E's DR portfolio during the 2018-2022 funding cycle.

The *Support for Retail and Customer-Facing Activities* sub-category funds systems support for the following retail activities: customer enrollment, aggregator enrollment and nominations, event forecasting, event dispatch, customer notifications, and retail program settlement calculations.[1]

The *Support for Market Activities* sub-category funds the systems and personnel to enable PG&E's Base Interruptible Program, Capacity Bidding Program (CBP), and SmartAC™ programs to be registered in the CAISO Demand Response Registration System (DRRS) such that they can be dispatched as a Supply Resource DR by PG&E. This budget also funds enhancements and services to support the changes to CBP approved in the 2018-2022 DR Application.

With the successful roll out of DRMI and attendant business processes, PG&E no longer sees a need to separately track the operational costs associated with retail and market activities. PG&E proposes that the

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1 Retail Program settlements are not CAISO settlements.

following costs be tracked under a single *Demand Response Operations* sub-category over the 2024-2027 cycle, which will include:

- DR Operations Labor;
- IT Systems and Services Contracts;
- IT Systems O&M Labor; and
- Support Organizations Charge-ins.

For the 2024-2027 funding cycle, PG&E requests an initial budget of $33,534,000 to cover costs under this new *Demand Response Operations* category. As described in Exhibit (PG&E-2) Chapters 1 and 3, this funding will be critical to meeting PG&E's goals of doubling the size of its DR portfolio by 2027. Accordingly, technologies supporting PG&E's DR programs must evolve over the 2024-2027 period to better fit customers and grid needs. DR IT systems will be required to perform more complicated transactions and interface with technologies that have new and different operating characteristics. Table 6-2 summarizes PG&E's budget request for DR Operations.

TABLE 6-2
DR OPERATIONS BUDGET REQUESTS 2024-2027
(MILLIONS OF DOLLARS)

Line No.	Budget category	2024	2025	2026	2027
1	DR Operations Labor (FTEs)	$1.76	$1.82	$1.89	$1.95
2	IT Systems and Services	2.15	2.15	2.15	2.15
3	IT Systems O&M Labor (FTEs)	3.52	3.65	3.77	3.91
4	Support Organizations Charge-in	0.63	0.65	0.67	0.71
5	Total	$8.06	$8.27	$8.48	$8.72

PG&E requests the ability to submit supplemental budget requests via the Tier 3 Advice Letter (AL) process, as needed, during the four-year budget period to address new system enhancements needs as they emerge.

2. IT Systems and Service Contracts

The DRMI system provides a single interface for DR operational market activities wherein PG&E is the DR provider. PG&E's ability as the DR provider, and the ability of third-party aggregators in its program, to use a customer in a CAISO market resource (i.e., be included in a Proxy Demand Resource [PDR] or Reliability Demand Response Resource [RDRR]) is contingent upon there being a seamless integration across multiple systems, including internal and external vendor systems (i.e., customer/aggregator portals), and CAISO systems (i.e., DRRS via Application Programming Interfaces [API]). In this application, PG&E seeks $14.9 million to cover labor costs related to the operations and maintenance (O&M) of DRMI and related internal systems. PG&E also seeks $8.6 million to enhance the DRMI system and cover service contracts with IT vendors.

The DRMI system serves multiple purposes. It is a customer management system that serves as the system of record for all PG&E DR program customer enrollments. It allows DR operators to perform customer eligibility checks and manage customer enrollment workflows, determine which customers can be formed into market resources, and orchestrate registering the locations and resources at the CAISO. This platform is also responsible for the creation of bid packages to be sent to PG&E's Energy Procurement organization, which serves as the Scheduling Coordinator. It also manages the receipt of market awards or dispatch instructions from CAISO systems and subsequent creation of the retail event that supports performing in response to the CAISO market award. For real-time RDRR, this application will retrieve dispatch instructions from the CAISO Automated Dispatch System directly. For day-ahead PDR, PG&E's Energy Procurement team will receive the market awards and provide dispatch recommendations that are consistent with the program design and least-cost dispatch principles.

While the CAISO related market functions of registration, bidding, and the associated retail dispatch are automated, DR operators have the responsibility of monitoring, reviewing, and troubleshooting the market bids and awards. Operators also intervene if there are any exceptions or issues with any of the systems. DR operators work closely with PG&E's settlements team, who are responsible for the DR aggregated meter data validation and submission to the CAISO and for PDR/RDRR settlement validation and wholesale payment activities. PG&E's existing internal enterprise systems support CAISO's meter data requirements – for instance, the transformation of 15-minute to 5-minute interval data for RDRR (real-time), and the transformation from Validation, Editing, and Estimation (Revenue Quality Meter Data) to Settlement Quality Meter Data.

DR Operations works with external vendors whose products and services support the core functionality of DRMI and enable day-to-day processes. These products and services include forecasting, enrollment processing, customer notification, data management, and settlement calculations. The DR Operations team supports these functions by troubleshooting with vendors when issues arise, identifying necessary product/service enhancements, and keeping vendors accountable to their deliverables.

Future DRMI enhancements under consideration include new functionality to improve the existing BIP direct enrollment portal and create a new portal for BIP and CBP Aggregators. In addition, PG&E plans to develop new APIs to speed up the transfer of data between its systems and third-party vendors managing new DR Pilots.

3. Demand Response Operations Labor

DR programs are supported by a business team dedicated to the day-to-day operations and supporting the complete DR customer lifecycle. In this application, PG&E seeks $7.4 million to cover DR Operations labor costs over the 2024-2027 period. Key work performed by the DR operations team includes, but is not limited to, the following:

- Participating in the DR Emergency Team rotation to provide 24/7 support for grid reliability;
- Managing the customer lifecycle in DR programs, including enrollment, location submission, Resource Registration, forecasting, bidding, event dispatch, performance measurement, and final settlement;
- Reviewing current work practices for operational efficiencies and deficiencies and providing feedback, follow-up, and recommendations for improvement to meet business and organizational needs;
- Tracking metrics and Key Performance Indicators to provide relevant information on operational efficiency to Program Managers and senior leadership;

- Managing relationships with vendors, including contract management, tracking system performance, and identifying future enhancement requests;
- Assisting in DR program design by aligning DR rules, policies, and programs with PG&E's technical capabilities; and
- Managing the integration and operation of the DRMI system with other existing systems and processes. Implementing DR pilot programs into the DR portfolio and ensuring the processes align with the specified tariff requirements.

The business functions performed by the DR Operations team, the functionality afforded by DRMI and multiple vendor systems, and technical support provided by IT O&M personnel, will enable PG&E to continue supporting retail customers and market activities over the 2024-2027 period.

C. Rule 24 Program Operations

This section presents PG&E's Rule 24 program operations budget for 2024 through 2027. PG&E anticipates that it will need to support mass market levels for Rule 24 beginning in 2022 and continuing throughout the 2023-2027 funding cycle. PG&E's forecasts of Rule 24 data sharing authorizations and CAISO DRRS Locations to be supported during this period are presented in Tables 2-4, 2-5, and 2-6 of Exhibit (PG&E-1) Chapter 2 (2023 Bridge Funding Proposal). PG&E's budget for 2024-2027 is organized and comprised of the same main components as the 2023 budget: (1) Rule 24 Business Team FTEs, (2) Vendor Costs for Customer Information Service Request For Demand Response Provider (CISR-DRP) Form Processing, (3) IT O&M, and (4) IT Systems Enhancements.

1. Summary of PG&E's Rule 24 Program Budget Request for 2024-2027

PG&E's budget request for 2024-2027 is summarized in Table 6-3 below.

TABLE 6-3
RULE 24 PROGRAM BUDGET REQUEST 2024-2027
(MILLIONS OF DOLLARS)

Line No.	Budget Item	2024	2025	2026	2027
1	Rule 24 Labor (FTEs)	$1.66	$1.71	$1.77	$1.84
2	CISR-DRP Form Processing	0.04	0.04	0.04	0.04
3	IT O&M				
4	IT O&M FTEs	0.58	0.60	0.62	0.64
5	Licenses	0.10	0.10	0.11	0.11
6	Cloud Fees	0.21	0.21	0.21	–
7	IT System Enhancements				
8	General Enhancements	0.79	0.81	0.84	0.87
9	Total	$3.36	$3.47	$3.59	$3.50

Each of the main components of the Rule 24 program budget are discussed in the sections below. Before presenting the detailed description of each budget component, PG&E first discusses issues pertaining to the timing for when PG&E is authorized to start work on its pending Click Through Application to transition the on-premise ShareMyData (SMD) platform to cloud-based service.[2]

2. PG&E's Proposed Click Through Enhancements Will Support Mass Market Participation Level for Rule 24 on a Long-Term Basis, but the Timeframe for Implementing the Enhancements Is Uncertain

PG&E's Click Through Application includes a proposal to transition the SMD on-premise infrastructure onto an Infrastructure-as-a-Service (IaaS) or cloud-based service. Migrating SMD to a cloud-based service is intended to facilitate quick data response at mass market levels.[3] As described in the

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2 PG&E Improvements to Click Through Customer Data Access Application Updated Testimony, Application (A.) 18-11-015, (originally filed on Nov. 26, 2018, updated on Sept. 10, 2019, and updated a second time on Nov. 13, 2020).

3 In written testimony supporting PG&E's Click Through Application, PG&E stated, "[n]evertheless, PG&E notes that at some point, the growth of customer data access will outstrip the existing capability of the SMD system, and this will stress currently achieved performance with the potential to degrade customer experience and third-party utilization of the SMD system. To prevent such outcomes, it is also important for PG&E to enhance its systems to be more flexible and resilient to changes in incoming data access request volumes." A.18-11-015, Exhibit PGE-0001, p. 2-24, lines 8-14.

Click-Through Application, PG&E proposed two items for improved quick data delivery. These are described below:

- Upgrade of PG&E SMD data inbound and outbound to IaaS to be compatible with projected future data volume expansion; and
- Upgrade of PG&E SMD supporting data layer to IaaS such that API requests made with complex query parameters can be processed to the extent possible with newer big data methods and technology.

PG&E's cloud-based SMD will be designed to be flexible in terms of its ability to scale up to meet increasing volumes of data sharing authorizations. By shifting away from a physical server infrastructure to a virtual server platform in the cloud, PG&E will be able to scale its SMD capacity through software configuration changes instead of installing hardware servers. Once completed, the update to SMD is expected to enable the platform to adapt quickly to changes in market volumes without sacrificing performance responsiveness for data access.

If the CPUC approves PG&E's Click Through Application, PG&E estimates it will take approximately 24 months after the date of approval to complete implementation of the cloud services. Given that the timing of the work is dependent on receiving Commission approval for PG&E's Click Through Application, the deployment timeframe of cloud-based SMD is uncertain. If the Commission approves PG&E's Click Through Application before the end of 2022, PG&E estimates it could be possible to implement the cloud-based SMD towards the latter part of 2024. A Commission decision in 2022 is desired because PG&E is concerned that its on-premise SMD platform might not be able to sustain adequate performance responsiveness at mass market levels for the medium growth case possibly in 2025, at which time the SMD platform will be ten years old.

In Section 5 below, PG&E discusses the annual O&M costs for the cloud services based on an assumption that the SMD cloud services are deployed at some point in 2024.

3. Rule 24 Labor

For the 2024-2027 period, PG&E's budget includes funding to support up to 9 FTEs. As discussed in Exhibit (PG&E-1) Chapter 2, Section D.1 (2023 Bridge Funding Proposal), PG&E believes that additional FTEs might be needed to keep pace with day-to-day operations activities commensurate with the expected significant increase in the volume of new Rule 24 data sharing authorizations and CAISO DRRS Locations. While funding is proposed for up to 9 FTEs, PG&E intends to increase the size of the business team beyond the current level of 5.5 FTEs gradually and on an as needed basis commensurate with increased workload as opposed to filling all positions at once.

Table 6-4 below summarizes PG&E's budget request for up to 9 FTEs for the Rule 24 program business team.

TABLE 6-4
ANNUAL RULE 24 BUSINESS TEAM FTE COSTS
(MILLIONS OF DOLLARS)

Line No.	2024	2025	2026	2027
1	$1.66	$1.71	$1.77	$1.84

4. Vendor Costs for Customer Information Service Request For Demand Response Provider Form Processing

As discussed in of Exhibit (PG&E-1) Chapter 2, Section D.2 (2023 Bridge Funding Proposal), while PG&E expects that the Click Through process will continue to be the dominant pathway for customers to authorize data sharing, the CISR-DRP Form will continue to be used by some DRPs, particularly those who primarily focus on providing DR services to the Commercial and Industrial sector. PG&E's budget for the 2024-2027 period includes funding for the continued use of an outside vendor to process CISR-DRP PDF forms received from third-party DRPs. Table 6-5 below presents PG&E's budget request to support CISR-DRP form processing. The annual cost is escalated by 5.0 percent per year based on an assumption that vendor costs could increase during the four-year budget authorization period.

TABLE 6-5
ANNUAL VENDOR COSTS

Line No.	2024	2025	2026	2027
1	$36,750	$38,588	$40,517	$42,543

5. Information Technology Operations and Maintenance

PG&E's proposed budget for annual O&M for the period 2024-2027 consists of three main items: (1) FTEs; (2) Licenses; and (3) Cloud-based service costs for SMD. Each of these items is described in more detail below. Table 6-5 presents PG&E's forecast for these three items.

a. IT O&M Full-Time Employees

As discussed in Exhibit (PG&E-1) Chapter 2 (2023 Bridge Funding Proposal), for 2023, PG&E proposes to increase the number of IT O&M resources from 1.5 FTEs to 2.5 FTEs and to continue to utilize IT developers and testers to support code fixes and enhancements on an as-needed basis. For the 2024-2027 period, PG&E proposes to maintain this level of IT O&M support. The FTE costs are presented in Table 6-6.

b. License Costs

The license costs cover the various IT systems and applications that will support the Rule 24 program, including the data warehouse used to support data access by third-party DRPs, Tableau, and SalesForce (as discussed below). These license costs are estimated at $98,000 in 2024 escalating to $109,000 in 2027.

c. Cloud-Based Service Costs for ShareMyData

PG&E's budget request includes an annual service cost to cover the Rule 24 program's allocation of cloud-based service fees for SMD. This cost is estimated at $210,000 per year. The $210,000 figure represents the proportion of SMD platform usage attributed to the Rule 24 program at the mass market volumes discussed in Exhibit (PG&E-1) Chapter 2 (2023 Bridge Funding Proposal). The Rule 24 mass market volumes were not known at the time PG&E filed its updated Click Through Improvements Application and therefore the incremental cloud service costs attributed to the Rule 24 mass market scale are not accounted for in that Application. In this application, PG&E is requesting cost recovery for the Rule 24 share of the cloud-based service costs for 2024 through 2026 only.[4] PG&E is omitting the cloud-based service costs for 2027 from this Application because PG&E intends to request cost recovery for this item in the 2027-2030 General Rate Case, starting with 2027. This approach is in line with PG&E's cost recovery proposal included in its Click Through Improvements Application.[5]

TABLE 6-6
ANNUAL RULE 24 IT O&M

Line No.	Item	2024	2025	2026	2027
1	FTEs	$577,000	$598,000	$619,000	$640,000
2	Licenses	98,000	101,000	105,000	109,000
3	Cloud Services Costs	210,000	210,000	210,000	–
4	Total	$885,000	$909,000	$934,000	$749,000

6. IT Systems Enhancements

PGE seeks funding in this Application to cover the costs associated with IT maintenance and enhancement work during 2024-2027 to the various IT systems and processes that are utilized for program administration. PG&E proposes an annual funding amount to support enhancements to maintain and improve operational efficiencies and functionality as well to maintain systems alignment with other related upstream systems for SMD and Rule 24 systems on an ongoing basis. This category of general IT enhancement work is described in detail in of Exhibit (PG&E-1) Chapter 2, Section D.4.a

4 The cloud-based service costs would be incurred only if the CPUC approves PG&E's proposed SMD IaaS proposal as part of the PG&E Improvements to Click Through Customer Data Access Application Updated Testimony, A.18-11-015, Exhibit PGE-0001. The $210,000 annual cloud-service cost is assumed to start in 2024, which represents the assumed completion date of the SMD migration from an on-premise to a cloud-based service.

5 In written testimony supporting PG&E's Click Through Application, PG&E stated, "[t]herefore, PG&E has adjusted its cost estimates to remove 2019 and 2020 costs and add costs for three later years, 2024, 2025 and 2026, to bridge the gap to reach the 2027 GRC I test year. Subsequently, the project costs can be included in the 2027 GRC 1." A.18-11-015, Exhibit PGE-0001, p. 2-33, lines 19-22.

(2023 Bridge Funding Proposal). PG&E notes that whereas the budget for 2023 includes a separate budget item in the amount of $1.204 million for specific IT enhancements to support mass market levels, which is in addition to funding for general IT enhancement work, PG&E is not requesting funding for specific IT enhancements for the 2024-2027 period. This is because once the specific IT enhancements as described in of Exhibit (PG&E-1) Chapter 2, Section D.4.b (2023 Bridge Funding Proposal) are completed in 2023, the annual funding amount for general IT enhancements should be sufficient to cover enhancements that are needed on an ongoing basis for systems alignment, efficiency improvements, maintenance and updating of IT testing tools, and for improvements for systems functionality.

Table 6-7 below summarizes PG&E's budget request for general IT enhancements.

TABLE 6-7
ANNUAL RULE 24 IT ENHANCEMENTS

Line No.	Item	2024	2025	2026	2027
1	General Enhancements	$785,000	$811,000	$839,000	$868,000

PG&E requests the ability to submit supplemental budget requests via the Tier 3 AL process, as needed, during the four-year budget period to address new system enhancements needs as they emerge.

7. Meter Reprogramming

As discussed in Exhibit (PG&E-1) Chapter 2, Section E (2023 Bridge Funding Proposal), PG&E believes that the existing funding authorization for meter reprogramming will be sufficient to support over the air meter reprogramming for residential customers up to the mass market levels for the medium growth case of CAISO Locations, where PG&E is the Meter Service Provider and Meter Data Management Agent, to be performed only after the residential customer has been successfully registered in the CAISO DRRS. PG&E extends its commitment to not charge DRPs for the over-the-air meter reprogramming for residential customers at mass market levels and will submit an AL proposing the conforming revisions to PG&E

Electric Rate Schedule E-DRP following the approval of proposals in this application.

D. PG&E's Billing System Modernization Project

PG&E does not anticipate the need to modify its billing systems to implement any DR proposals for this cycle. The timeline for delivery of any directives resulting from a decision in this proceeding that might require structural modifications to PG&E's billing system would need to be assessed. Over the next several years, PG&E will be replacing/upgrading its two billing systems: the complex billing system, called the Advanced Billing System will be replaced with Oracle's Billing Cloud Service, and the mass market billing system, Oracle's Customer Care and Billing System will be upgraded to Oracle's Customer to Meter billing system. Because of the complexity and duration of the Billing System Modernization project, and the current backlog of Commission ordered rate changes that require billing system structural changes, any additional work could introduce significant risk to the overall timeline for completion of the entire Billing System Modernization project and the ability to build future new rates. The current backlog of approximately 20 rate implementations that have already been mandated, or will soon be, must be built in the period of the Billing System Modernization project. PG&E is constantly working to align the prioritization of this work with regulatory expectations as new directives arise, but the bandwidth to introduce new rates or rate structure changes is constrained during the Billing System Modernization project.

E. Conclusion

For the 2024-2027 funding cycle, PG&E requests an initial budget of $33,534,000 to cover costs under the new consolidated *Demand Response Operations* category to support PG&E DR operations. The DR operations proposed annual budget is presented in Table 6-1. To support Rule 24 program operations for the 2024-2027 funding cycle, PG&E requests an initial budget of $13,916,000. The Rule 24 program annual operations budget is presented in Table 6-2. As discussed in this chapter, PG&E requests the ability to submit supplemental budget requests via the Tier 3 AL process, as needed, during the four-year budget period to address new system enhancements needs as they emerge.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

LOAD IMPACTS, MEASUREMENT, AND EVALUATION

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CHAPTER 7
LOAD IMPACTS, MEASUREMENT, AND EVALUATION

A. Introduction

This chapter describes the Measurement and Evaluation (M&E) activities and Load Impact (LI) estimates for Pacific Gas and Electric Company's (PG&E) Demand Response (DR) portfolio for 2024-2027. The goal of PG&E's DR M&E activities is to provide valuable insight on the design, operation, and effectiveness of PG&E's DR offerings. This is done through rigorous evaluation and research, in order to inform Resource Adequacy (RA), resource planning and improve program operations to enable DR to achieve its potential. Our recommendations include: (1) continuing the annual load impact evaluation of each of PG&E's DR programs; (2) conducting research studies to improve cost effectiveness and to shape future program designs; (3) refining DR bid forecasting and permanent valuation methodology for resource adequacy; (4) updating the list of dockets for the DR annual load impact reports; and (5) retiring an irrelevant reporting requirement.

B. Scope of Measurement and Evaluation

The overarching goal of M&E is to provide useful insight to optimize program performance and to generally advance DR. Specifically, PG&E's M&E studies will support DR in the following areas:

1) <u>Investor-Owned Utility (IOU)-Administered DR Programs</u> – Impact evaluations of PG&E DR programs provide useful information about DR program attributes, load reduction capacity at various levels of granularity, and customer acceptance. These evaluations will continue to form the basis for recommendations for RA, the Integrated Resource Planning (IRP), and DR cost effectiveness analyses. PG&E will continue to carry out robust impact evaluations in keeping with the DR Load Impact Protocols (LIP)[1] to produce ex post and ex ante impact estimates for DR programs

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[1] D.08-04-050, *Decision Adopting Protocols for Estimating DR Load Impacts*; D.10-04-006, *Decision Modifying Demand Response Load Impact Report Annual Filing Requirements*.

2024-2027,[2] subject to California Public Utilities Commission (CPUC or Commission) RA decision with respect to DR counting methodology.[3] Ex post impact estimates (i.e., historical performance)[4] are used to inform ex ante estimates (i.e., weather-adjusted performance under system peak conditions) for long-term resource planning. These LI evaluations typically use sophisticated statistical methods that are more rigorous than settlement baselines. While settlement baselines can provide some crude estimates about the performance of a program, their level of rigor is insufficient for proceedings such as RA or IRP. The LI evaluations will continue to be used to inform resource planning.

2) Verification of Prohibited Resources Compliance – Certain fossil-fueled back-up generations are prohibited to provide load reduction during DR events and receive incentives. The prohibition applies to DR programs including Base Interruptible Program (BIP) and Capacity Bidding Program (CBP). Customers participating in these programs are required to attest whether they possess prohibited resources on-site and whether the prohibited resources will be used to provide load reduction during DR events. To verify customer compliance with the prohibition, an annual audit by the Verification Administrator will be conducted to inspect and validate customer attestations, until the CPUC lifts the verification requirement off the IOUs.

3) DR Bid Forecast – It is well-known that DR is a variable-output resource, whose load reduction capability is time-varying and weather sensitive to some extent. As the supply-side DR resources (e.g., BIP, CBP,

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2 D.21-06-029 has requested the California Energy Division to lead a working group process to develop recommendations for a new Qualifying Capacity (QC) counting methodology for DR. The CPUC will consider the recommendations for implementation in the 2023 RA compliance year or thereafter.

3 In 2021 and 2022, the CEC conducted a number of workshops to determine an interim methodology for evaluating the QC of DR resources for 2023 compliance year. In February 2022, the CEC issued a report including recommendations for CPUC action; a summer 2022 decision is expected in the RA proceeding (Rulemaking (R.) 21-10-002) on an interim QC methodology.

4 See more details in Sections C and D of this chapter.

SmartAC™[5]) are bid into the California Independent System Operator (CAISO) markets, it is important that the bids realistically reflect the true capacity of the resources, so that the CAISO can accurately forecast how much DR can be expected when dispatched. To that end, PG&E continues to refine the bid forecasting methodology to account for the fluid customer mix.

4) Evolving Grid Needs and Grid -Responsive Loads – The complexity of the analytics for DR is growing with the evolution of grid needs[6] and the increasing adoption by customers of new Behind-the-Meter (BTM) technologies—such as device automation tools, energy storage, Electric Vehicles (EV), and EV charging stations—that can provide DR once enrolled in a DR program. Changes in load can thus be attributed to a multitude of dynamic and inter-related factors. Changes to the timing, locations, and technologies called as part of DR events will also create growing challenges for DR event performance analyses and forecasts. Not only must these factors be studied and accounted for, new techniques for their estimation and measurement also must be developed and vetted.

To continue to provide accurate historical events analyses and forecasts that capture and reflect the value of DR in light of the evolving grid needs and the role of grid responsive loads, PG&E will ensure that the LI evaluations of existing DR programs address these elements to the extent practicable and appropriate. Additional dedicated studies and work may be conducted as follows:

- Impact evaluations for the enhancements proposed for PG&E's Automated Demand Response (ADR) Program and BTM technologies, including their ability to act as grid-responsive loads serving the evolving needs of the grid;
- A Market Potential Study: As described in Exhibit (PG&E-2) Chapter 2, PG&E seeks to increase DR enrollment in distribution and transmission constrained areas. In this chapter, we propose a Market Potential Study to

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5 The name SmartAC or SmartRate is a registered trademark of PG&E. All further references to the program in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

6 As referenced in Exhibit (PG&E-2), Chapters 1 and 2 of this testimony.

identify DR capacity potential in these areas. Study findings will shape enrollment strategies by targeting high impact areas to achieve better cost-effectiveness.

- Continuing research to better understand market integration efficacy and load response of customers that enroll in DR programs while simultaneously engaging in energy efficiency, self-generation, energy storage, EVs, and other BTM Distributed Energy Resource technology programs. As discussed in Chapter 2, PG&E is proposing a Market Integration Efficacy Study[7] and a Load Flexibility Study,[8] which will identify and disaggregate end-use loads to help address operational and planning needs, and to shape future program design.
- Continuing efforts to improve DR load forecasting to meet the evolving electric grid needs, such as developing strategies to determine reliable DR load estimates for RA and analyzing LIs in more granularity (i.e., Sub-Load Aggregation Points (Sub-LAP) or varying weather scenarios, to meet CAISO needs).

Statewide evaluations, where feasible, can result in cost savings. PG&E proposes statewide studies be conducted when either of the following applies: (1) programs in questions are fairly comparable across the IOUs, or (2) the research questions are general in nature and relevant for all the IOUs.

PG&E will continue to work closely with the Demand Response Measurement and Evaluation Committee (DRMEC) and interested stakeholders to integrate LIP-compliant *ex ante* LI estimates in resource planning processes, such as RA and IRP.

C. Ex Post Load Impacts Analysis

This section explains the background on the ex post LIs portion of the annual LI evaluations and also provide context for the ex ante impacts set out in the next section. Ex post analysis measures the load impacts observed from historical dispatch events that occur during the program year. Results summarize the actual customer load response to DR events under observed dispatch conditions. Ex post LIs are then used to inform ex ante LIs, which

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[7] See Chapter 2, Section B.2 for detail.

[8] See Chapter 2, Section B.1 for detail.

represent an 11-year forecast under pre-defined peak weather conditions and RA measurement hours.

For PG&E's administered programs, the impact evaluations will continue to include ex post impact estimates. Ex post LIs are calculated as long as there are events, including test events, called in a program year (PY). For the 2024-2027 PYs, the IOUs will continue to conduct an *ex post* LI evaluation for each DR program keeping with the LIPs. Typically, the ex post analysis will estimate:

- The LI of the average event (in the case of multiple annual events) on both a per-customer basis and in aggregate;
- The LI of each event, on both a per-customer basis and in aggregate;
- The LI by CAISO Local Capacity Area and Sub-LAP; and
- The distribution of LIs for the average event by customer class where customer class may be a business type or some other classification

The ex post LI evaluations will also estimate the incremental effect of enabling technology, to the extent feasible. The impact evaluation scope may expand beyond the minimum requirements of the LIPs if additional analysis is needed to support future program design improvements. Recommendations will be provided in ex post LI evaluations for future program operations and designs.

While ex post LI results indicate the observed historical performance of DR programs, ex post results alone are not sufficient in illustrating the full LI capacity of DR programs. This is due to how DR events are dispatched in recent years. In most scenarios, DR programs were dispatched in response to local or grid emergency events or CAISO market awards. This means DR programs are often times dispatched by a subset of CAISO Sub-LAPs, rather than at the program level. Additionally, Sub-LAP and program dispatches may be staggered across varying event hours or event days. Along with differing weather conditions across event days and customer segments, this poses challenges to systematically quantifying the full LI potential of the DR portfolio. To allow for an apples-to-apples comparison of total available DR megawatt (MW) capacity across programs and weather conditions, ex ante estimates are used. In compliance with the LIPs, ex post results serve as inputs to ex ante LI estimation, which will be discussed in the next section.

D. Ex Ante Load Impact

In each annual LI evaluation, PG&E produces ex ante LI estimates under utility and CAISO 1-in-2 and 1-in-10 standardized peak weather conditions, for the RA measurement hours, 4-9 p.m. This provides a consistent basis to interpret DR capacity for forecasting purposes and also provides a helpful tool to interpret what is the total available DR capacity, even when only a portion of the DR portfolio was dispatched for historical ex post events.

To illustrate the total available DR capacity in 2018-2022, below we show a comparison of actual enrollments in August for 2018-2021 in Table 7-1 and the estimated total capacity in Table 7-2 based on the ex ante LIs from the respective year's LIP filings.

TABLE 7-1
NUMBER OF PARTICIPANTS BY DR PROGRAM IN AUGUST FOR 2018-2021

Line No.	Program	2018	2019	2020	2021
1	BIP	461	514	493	306
2	CBP	531	797	1704	943
3	SmartAC	111,912	100,727	90,026	81,564
4	Total Enrollment	112,904	102,038	92,223	84,280

Note: CBP enrollments are based on aggregator nominations.

Table 7-2 summarizes the total available August capacity in 2018-2021. This is calculated by multiplying the actual August enrollments (as shown in Table 7-1), by the ex ante per customer LI for the program. The MW estimates below reflect what PG&E's DR programs can provide individually and at the portfolio level in August for 2018-2021 if all the program customers were dispatched simultaneously.[9]

[9] Instead of the ex post impacts, the projected ex ante impacts are presented here because not all DR programs were necessarily dispatched simultaneously during the system peak. The ex post impacts may or may not be representative of the portfolio's capacity available at the time.

TABLE 7-2
BACKCAST EX-ANTE MW CAPACITY ADJUSTED WITH ACTUAL ENROLLMENTS BY DR PROGRAM IN AUGUST FOR 2018-2021

Line No.	Program	2018	2019	2020	2021
1	BIP	281	310	227	184
2	CBP	34	30	44	61
3	SmartAC	54	49	44	19
4	Total MW	369	391	296	219

Note: CBP enrollments are based on aggregator nominations.

The LIs in Table 7-2 assumes events are called for the RA assessment hours (i.e., 4-9 p.m.) under utility 1-in-2 weather conditions. Additional drivers for 2018-2021 LI trends are discussed below:

1) BIP impacts follow the enrollment trends in Table 7-1, where MW capacity is highest in 2019, but decreases in subsequent years due to decreased enrollments.
2) CBP LIs are mainly driven by aggregator nominations and exhibit an increasing trend from 2019-2021.
3) SmartAC LIs gradually declined from 2018 to 2020 due to customer attrition. The sharper decline between 2020 and 2021 is due to modification of an ex ante assumption. In the 2020 LI evaluation, the SmartAC ex ante methodology modified the assumption by using Sub-LAP events as its basis to better reflect how the program was typically dispatched, which is by Sub-LAP. In prior SmartAC evaluations, program-wide events were assumed to be dispatched by device serial groups,[10] which provided higher LIs given the way the control devices were programmed. However, with SmartAC integrated into the CAISO energy market in 2018, most events pivoted to Sub-LAP level dispatches. Sub-LAP events were consistently outperformed by program-wide events because legacy paging devices have historical issues responding to Sub-LAP dispatch signals. This explains the sharp decrease in LI for 2021.

[10] SmartAC devices in the program-wide events were dispatched by group based on the last digit of the serial number of the control device.

Consistent with the Load Impact Protocols, SmartAC LIs are estimated across the 5-hour RA assessment window. However, these estimates may be lower than the observed load impacts in recent year's events. Market-awarded SmartAC events typically last two or three hours; only when an emergency event is called will PG&E dispatch SmartAC for longer than three hours. Due to the limited number of SmartAC historical events that last five hours, there's higher uncertainty in the load impact estimates for the fourth and fifth hours of the RA assessment window. Additionally, under the 1-in-2 (average peak) weather conditions, the temperatures for 7-9 p.m. drop off significantly compared to the earlier hours (upwards of 10 degrees, from around 100 degrees Fahrenheit (°F) to 90 F). Since SmartAC impacts are driven by temperature, these conditions significantly reduce the load impacts of the later hours, as well as the average hourly impact of the 5-hour event, which is used for the cost effectiveness calculation. The combination of these two factors means an event which persists for five hours, and at significantly lower temperatures during later hours (8-9 pm), may under-represent the load impact of a typical SmartAC event.

For PYs 2024-2027, PG&E will continue to conduct ex ante LI analysis of its DR programs.

Table 7-3 summarizes the updated portfolio-adjusted ex ante LI estimates for August 2024-2027, reflecting the proposed program changes. These are portfolio-adjusted LIs, where dual participation between DR and rates programs (Critical Peak Pricing [CPP] and SmartRate) has been taken into account. The allocation of LIs is consistent with the dual participation rules. Monthly LIs can be found in Chapter 7 Attachment A, which contains the updated ex ante portfolio LIs for DR programs on each monthly system day under PG&E Peaking Conditions and 1-in-2 weather, for 2024 through 2027.

TABLE 7-3
PORTFOLIO-ADJUSTED EX ANTE LOAD IMPACTS (MW) FOR AUGUST UNDER PG&E PEAKING CONDITIONS AND 1-IN-2 WEATHER FOR 2024-2027

Line No.	DR Resource	2024	2025	2026	2027
1	BIP	319	319	319	319
2	CBP	73	82	91	100
3	SmartAC	23	20	18	17
4	ART	60	75	88	102
5	Total	475	496	516	538

The ex ante LIs in Table 7-3 are based on the LI filings on April 1, 2022, but revised to reflect the changes to each specific program proposed in this application.

The assumptions of the ex ante LIs are specified as follows:

1) Events are called for the RA assessment hours, i.e., 4-9 p.m.
2) BIP:
   - In response to the increased need for interruptible load due to high energy price spikes and emergency events in recent years, PG&E proposes various BIP program enhancements to mitigate customer attrition and encourage new participation, as described in Exhibit (PG&E-2) Chapter 3, Section B.2. The BIP MW forecast reflects enrollment growth resulting from the higher program incentives, additional marketing efforts, and additional enhancements proposed in Chapters 2 and 3. The proposed adjustments to event limits also aim to prevent customer fatigue and attrition. The MW is projected to reach the previous reliability MW cap of 330 MW during peak month (June).
   - Lower impacts are estimated for other months, which are consistent in pattern with the LIs observed in the PY 2021 LI evaluation.
3) CBP:
   - The program forecasts 11 to 15 percent annual increase in MW, which represents a slower growth rate than the substantial growth observed in recent years (nearly double in nominated MWs from 2019 to 2021). The substantial growth in recent years is not assumed to be sustainable for the next budget cycle.
   - Additionally, due to the proposed monthly testing processes, revised incentives, and other program enhancements discussed in (PG&E-2)

Chapter 3, Section C, the forecast applies a 90 percent nomination achievement rate to projected aggregator nominations—that is, the CBP aggregators are assumed to deliver 90 percent of their nominated capacity when tested. The monthly testing changes aim to improve operational readiness for systems and customers as well as provide transparency to resources performance.

- Given historical nominations, all the nominated customers subscribed to the 1-4 hour product, meaning that the program did not support a 5-hour event. To reflect this, the ex ante impacts assume 0 MW for the last hour of the RA measurement window.
- The CBP capacity price varies month to month and so does the monthly ex ante impact.

4) <u>SmartAC</u>:

- Program participants will be dispatched through installed two-way load control switches (LCS).
- Starting 2024, no new customers will be enrolled into the program.
- Based on historical enrollment trends, LCS devices are assumed to experience an annual attrition of 10 percent.
- Smart controllable thermostats (SCT) in the program would transition to the proposed Automated Response Technology (ART) program in the beginning of 2024, as further discussed in (5) below.
- As previously discussed, SmartAC LIs were estimated across the 5-hour RA assessment window in accordance with the LIP and 2016 DR Cost Effectiveness (CE) Protocols. It's important to note that estimating SmartAC load impacts across the entire RA window diminishes the average hourly load impact and thus cost effectiveness due to the following reasons: (1) SmartAC load impacts typically peak in the first three event hours and drop off in later hours; (2) cooling load in the PG&E service territory peaks in the afternoon and declines significantly in the evening hours, which reduces load impact potential for the program in later hours; and (3) the lower temperatures for 7-9 p.m. in the 1-in-2 peaking conditions (around 90 F) lead to lower estimated load impacts.

5) ART Program:

- Assumed in the load impact forecast are the following technologies: (1) smart thermostat, (2) electric vehicle, (3) battery discharging, (4) heat pump water heater, and (5) flexible appliances, e.g., pool pump and dryer. Table 7-4 presents the estimated per-device impact (kW) and the forecasted device count for 2024 through 2027.

TABLE 7-4
ART LOAD IMPACT ASSUMPTIONS BY TECHNOLOGY FOR AUGUST 2024-2027

Line No.	Technology	Per-Device Load Impact (kW)	Estimated Device Count			
			2024	2025	2026	2027
1	Smart Thermostat	0.54	90,000	96,667	106,667	116,667
2	EV	0.35	6,667	13,333	18,333	23,333
3	Battery Discharging	2.5	3,333	6,667	9,167	11,667
4	Heat Pump Water Heater	0.05	6,667	10,000	10,000	10,000
5	Flexible Appliance (e.g., Pool Pump and Dryer)	0.05	3,333	8,333	13,333	18,333

E. Load Impacts for Alternative Program Designs

As described in Exhibit (PG&E-2) Chapters 3 and 9, PG&E is offering alternative program designs for 2024-2027 to address challenges with cost effectiveness. This section discusses how the alternative program designs affect load impacts for each program. Table 7-5 summarizes the portfolio-adjusted ex ante LI estimates for August 2024-2027 under the alternative scenarios. Similar to Table 7-3, these are portfolio-adjusted LI under PG&E Peaking Conditions and 1-in-2 weather, where dual participation between DR and rates programs (i.e., CPP and SmartRate) has been taken into account.

TABLE 7-5
PROGRAM ALTERNATIVE EX ANTE LOAD IMPACTS (MW) FOR AUGUST UNDER PG&E PEAKING CONDITIONS AND 1-IN-2 WEATHER FOR 2024-2027

Line No.	DR Resource	2024	2025	2026	2027
1	BIP	261	261	261	261
2	CBP	86	97	108	119
3	SmartAC	23	20	18	17
4	ART	61	76	90	104
5	Total	431	454	477	501

The assumptions of the alternative LIs are specified as follows:

1) Events are called for the RA assessment hours, i.e., 4-9 p.m.
2) <u>BIP</u>:
   - The BIP MW forecast reflects lower MWs and less enrollment growth due to lower incentives, as discussed in Exhibit (PG&E-2) Chapter 3, Section B.4. The lower incentives aim to improve cost effectiveness, but may lead to fewer new enrollments from 2024-2027. The MW is projected to reach 270 MW during program peak month (June).
   - Lower impacts are estimated for other months, which are consistent in pattern with the LIs observed in the PY 2021 LI evaluation.
3) <u>CBP</u>:
   - As with the base case described in section 7-D, the program forecasts 11 to 15 percent annual increase in MW and 90 percent nomination achievement rate due to program enhancements.
   - However, rather than isolating participation to the 1-4 hour product, the alternative proposal extends the hours to the 4-11 p.m. window and utilizes a 1-5 hour event option. Unlike the base case, the ex ante impacts now assume consistent load impacts for the five hours of the RA measurement window, leading to higher overall average load impacts. This optimistic assumption is made in order to test the cost effectiveness for the alternate program design.
   - The alternative program design also proposes lower incentives to aid cost effectiveness. In response, the hourly CBP load impacts are estimated to decrease by 5 percent, compared to the base case.
   - The CBP capacity price varies month to month and so does the monthly ex ante impact.
4) <u>SmartAC</u>: PG&E is not providing any alternative SmartAC program design. The SmartAC MW forecast contains the same assumptions as described in in the previous section of this chapter, Section 7.D.
5) <u>ART Program</u>: PG&E is not providing any alternative ART program design than what is described in Exhibit (PG&E-2) Chapter 3, Section E. The ART MW forecast contains the same assumptions as described in the previous section of this chapter, Section 7.D.

Table 7-6 outlines the difference between ex ante MWs forecasted for the proposed program enhancements (Table 7-3) and the MWs resulting from the alternative program designs discussed in this section (Table 7-5).

TABLE 7-6
DIFFERENCE* IN EX ANTE LOAD IMPACTS (MW) BETWEEN PROPOSED PROGRAM ENHANCEMENTS AND ALTERNATIVE PROGRAM DESIGNS FOR AUGUST 2024-2027

Line No.	DR Resource	2024	2025	2026	2027
1	BIP	(58)	(58)	(58)	(58)
2	CBP	13	15	17	19
3	SmartAC	–	–	–	–
	ART	–	–	–	–
5	Total	(45)	(43)	(41)	(39)

Note: A positive value indicates an increase in MW from the base case.
A negative value indicates a decrease in MW from the base.

To improve cost effectiveness, the alternative designed DR Portfolio would observe a trade off in load impacts of 39 to 45 MW. BIP drives the largest load impact differences, with a loss of 58 MWs in August across the years. CBP impacts are higher for the alternative design, which is largely driven by the optimistic assumption that participants deliver consistent load impacts across the 4-9 p.m. in the RA measurement window.

F. Load Impact Protocols and Effective Load Carry Capacity

While DR's QC in the RA proceeding today is informed by the ex-ante LIs in compliance of the LIPs, the QC methodology in the future may be subject to change. The reform of the RA Program is underway. The CAISO has argued that supply side DR resources should be valued by taking into account their variable and energy-limited nature,[11] which the current valuation methodology—the LIPs—does not consider. In Decision (D.) 21-06-029, the Commission requested the California Energy Commission (CEC) to lead a working group process to develop recommendations for a comprehensive DR M&E strategy,

11 CAISO, Resource Adequacy Availability Assessment Mechanism (RAAIM) Exemption Option (June 10, 2021), p. 3, <http://www.caiso.com/Documents/FinalProposal-RAAIMExemptionOption-DRResources.pdf> (as of Apr. 21, 2022).

including a new capacity counting method for DR.[12] The CEC has submitted an interim report with recommendations for the interim year, while leaving the long-term QC methodology yet to be determined. A few proposals are recommended by the CEC report, including using the LIP profiles to inform the effective load carrying capacity (LIP-informed Effective Load Carry Capacity).

It is unclear what the future QC method will be, whether additional inputs will be needed (other than the ex-ante LI) and who should conduct the calculation. Nonetheless, the future calculation will likely be more complex than how it is done today because DR is no longer treated as a fixed resource, but as a variable resource whose MW varies depending on time and event conditions. How DR is evaluated depends not only on the resource's attributes, but also how it interacts with other intermittent resources in providing reliability to the grid. PG&E expects more analysis will be needed in the 2024-2027 funding cycle to determine how DR should be evaluated in resource planning.

Moreover, there will be ramifications for DR's cost effectiveness when a new QC methodology is adopted. Today, the ex ante LI informs the benefit side of the cost effectiveness calculation. If the QC of the resource is no longer valued as much as the ex ante LI, the cost effectiveness of the resource will be reduced accordingly, when the cost remains unchanged. PG&E requests the Commission to explicitly address the cost effectiveness calculation when a new QC methodology is adopted.

G. Updates to List of Dockets for Service of Load Impact Reports

PG&E requests that the Commission update the list of dockets in which the Annual Load Impact Reports and the monthly Interruptible Load Program (ILP) Reports would be served. The reports are currently served in a variety of dockets pursuant to directions that span several years. The Annual Load Impact Report filings and service of the Load Impact Reports originally were ordered in D.08-04-050 and served in R.07-01-041. Pursuant to an Administrative Law Judge's March 13, 2014 ruling, the April 2015 Load Impact Reports, and future reports, were to be served and filed in the Demand Response OIR, R.13-09-011. Then, in a February 10, 2020 e-mail from Energy Division entitled, "Updated Demand Response Impact Protocols 2020 Filing Requirements and Process,"

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[12] D.21-06-029, p. 35.

filing was also ordered in R.19-11-009 and Application (A.) 17-01-012, et. seq. The most recent RA docket, R.21-10-002, was also included for the draft load impact reports served in March 2022, with some IOUs also serving in R.19-11-009 and R.20-11-003. For the March 21, 2022 monthly ILP reports, the IOUs served in a variety of dockets; San Diego Gas & Electric Company in A. 08-06-001, A.08-06-002, A.08-06-003, A.11-03-001, A.11-03-002, A.11-03-003, and R.13-09-011; Southern California Edison Company in R.13-09-011 and A.12-01-012, et seq.; and PG&E in all the cases.

To update and provide consistency in the filling and service requirements, PG&E requests the Commission vacate the previous directions and approve the following requirements:

1) The Annual Load Impact Report filings and service will be in the current Demand Response Cycle Application and the most Current Resource Adequacy Docket, as of the date of filing. No other changes would be made.
2) The draft Annual Load Impact Reports would be served, but not filed, on parties on the service list for the current Demand Response Cycle Application and the most Current Resource Adequacy Dockets, as of the date of service.
3) The monthly ILP reports would be served, but not filed, on parties on the service list for the current Demand Response Cycle Application, as of the date of service.

H. Demand Response Interim Goal Report

In the Joint Proposal approved in D.14-12-024, as modified by D.15-02-007, parties agreed to an interim collective, statewide DR goal of 5 percent of the sum of the peak demands of the IOU by 2020. This interim DR goal would remain in effect until superseded by firm DR goals approved by the Commission that would be informed by a DR potential study.

PG&E proposes to retire the DR interim goal report beginning 2024, because the DR interim goal report is no longer relevant for its original purpose. The Joint Proposal, that prescribed the DR interim goal report, was intended to address issues before the implementation of bifurcation of DR programs. One of the issue areas identified by the Joint Proposal was DR goals. With a 5 percent statewide goal assumed at the time, the DR interim goal report was designed to measure the progress of IOU DR programs toward meeting that goal. When adopting the reporting requirement of the DR interim goal report, D.14-12-024[13] also directed Energy Division staff to complete a Demand Response Potential Study, with an objective to rigorously determine MW goals for DR. Now, the DR Potential Study has been long completed and the bifurcation of DR programs has been implemented for years. Considering the development of DR in the last few years, the 5 percent interim goal is outdated, which makes the DR interim goal report no longer necessary.

Also, the limited scope of DR interim goal report makes the results uninformative. Pursuant to D.14-12-024, the report only counts the LIs of certain IOU DR programs, leaving out: (1) the load reduction of the Demand Response Auction Mechanism, and (2) the load reduction third-party aggregators provide to other load serving entities. Given the omission of non-IOU DR resources, the report is hardly relevant for its original purpose now, only presenting the reader with an incomplete picture of how much total DR capacity is available during the time of the system peak.

I. Recommendations and Conclusion

M&E recommendations are summarized below:

1) Impact Evaluations and Prohibited Resource Verification

PG&E recommends conducting annual impact evaluations for the following programs:[14]

- ART;
- BIP;
- CBP; and
- SmartAC.

BIP and CBP have been evaluated jointly with the other IOUs for synergies in analysis and cost savings. We propose conducting statewide impact evaluations for these two programs for 2024-2027.

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13 D.14-12-024, pp. 83-84, OP 3.

14 Funding for the evaluation of CPP programs (i.e., SmartRate and Peak-Day Pricing) is requested in the General Rate Case, and therefore, not included in this application.

In addition, we request funding for the verification of prohibited resources compliance for 2024-2027 (unless or until the verification requirement is lifted).

2) *Research Studies*

In additional to annual LI evaluations, PG&E requests to conduct:

- Market Potential Study to identify DR capacity potential in transmission and distribution constrained areas;
- Load Flexibility Study to understand customer elasticity to various rates and DR signals;
- Market Integration Efficacy Study to inform future program design; and
- Additional M&E activities to refine DR bid forecasting and the permanent DR valuation methodology to inform resource planning.

3) *Updating the list of dockets to which the annual DR load impact reports will be filed and served and the list of dockets in which the draft annual DR load impacts and the monthly Interruptible load impact reports will be served.*

4) *Retiring the DR interim goal report due to its lack of relevancy today.*

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CHAPTER 7

ATTACHMENT A

PORTFOLIO ADJUSTED EX ANTE IMPACTS 2023-2027

Attachment 7A

Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions And 1-in-2 Weather for 2023-2027

Proposed Program Design:

Table 1: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2023 under Proposed Program Design

Load Impacts (MW) of DR Resource	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Base Interruptible Program (BIP)	208	208	220	240	252	260	250	252	258	247	233	216
Capacity Bidding Program (CBP)	0	0	0	0	23	33	54	63	43	49	0	0
SmartAC	0	0	0	0	38	72	74	72	65	24	0	0
Automated Response Technology (ART)												
Total	**208**	**208**	**220**	**240**	**313**	**365**	**378**	**387**	**366**	**320**	**233**	**216**

Table 2: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2024 under Proposed Program Design

Load Impacts (MW) of DR Resource	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Base Interruptible Program (BIP)	264	264	279	304	319	330	317	319	328	313	296	275
Capacity Bidding Program (CBP)	0	0	0	0	26	38	62	73	50	56	0	0
SmartAC	0	0	0	0	13	24	24	23	20	7	0	0
Automated Response Technology (ART)	1	3	4	6	34	60	61	60	56	29	15	17
Total	**265**	**267**	**283**	**310**	**392**	**452**	**464**	**475**	**454**	**405**	**311**	**292**

Table 3: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2025 under Proposed Program Design

Load Impacts (MW) of DR Resource	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Base Interruptible Program (BIP)	264	264	279	304	319	330	317	319	328	313	296	275
Capacity Bidding Program (CBP)	0	0	0	0	30	42	70	82	56	63	0	0
SmartAC	0	0	0	0	12	22	22	20	18	6	0	0
Automated Response Technology (ART)	17	18	19	20	49	75	76	75	70	40	24	25
Total	**281**	**282**	**298**	**324**	**410**	**469**	**485**	**496**	**472**	**422**	**320**	**300**

Table 4: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2026 under Proposed Program Design

Load Impacts (MW) of DR Resource	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Base Interruptible Program (BIP)	264	264	279	304	319	330	317	319	328	313	296	275
Capacity Bidding Program (CBP)	0	0	0	0	33	47	77	91	62	70	0	0
SmartAC	0	0	0	0	10	20	20	18	16	6	0	0
Automated Response Technology (ART)	26	26	27	28	60	89	90	88	83	50	33	33
Total	**290**	**290**	**306**	**332**	**422**	**486**	**504**	**516**	**489**	**439**	**329**	**308**

Table 5: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2027 under Proposed Program Design

Load Impacts (MW) of DR Resource	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Base Interruptible Program (BIP)	264	264	279	304	319	330	317	319	328	313	296	275
Capacity Bidding Program (CBP)	0	0	0	0	36	52	85	100	69	78	0	0
SmartAC	0	0	0	0	9	18	18	17	14	5	0	0
Automated Response Technology (ART)	34	35	35	36	71	103	104	102	96	60	41	42
Total	**298**	**299**	**314**	**340**	**435**	**503**	**524**	**538**	**507**	**456**	**337**	**317**

Alternative Program Design:

Table 6: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2023 under Alternative Program Design

Load Impacts (MW) of DR Resource	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Base Interruptible Program (BIP)	208	208	220	240	252	260	250	252	258	247	233	216
Capacity Bidding Program (CBP)	0	0	0	0	23	33	54	63	43	49	0	0
SmartAC	0	0	0	0	38	72	74	72	65	24	0	0
Automated Response Technology (ART)												
Total	**208**	**208**	**220**	**240**	**313**	**365**	**378**	**387**	**366**	**320**	**233**	**216**

Table 7: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2024 under Alternative Program Design

Load Impacts (MW) of DR Resource	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Base Interruptible Program (BIP)	216	216	228	249	261	270	260	261	268	256	242	225
Capacity Bidding Program (CBP)	0	0	0	0	31	45	73	86	59	66	0	0
SmartAC	0	0	0	0	13	24	24	23	20	7	0	0
Automated Response Technology (ART)	1	3	4	6	34	60	61	60	56	29	15	17
Total	**217**	**219**	**232**	**255**	**339**	**399**	**418**	**430**	**403**	**358**	**257**	**242**

Table 8: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2025 under Alternative Program Design

Load Impacts (MW) of DR Resource	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Base Interruptible Program (BIP)	216	216	228	249	261	270	260	261	268	256	242	225
Capacity Bidding Program (CBP)	0	0	0	0	35	50	83	97	67	75	0	0
SmartAC	0	0	0	0	12	22	22	20	18	6	0	0
Automated Response Technology (ART)	17	18	19	20	49	75	76	75	70	40	24	25
Total	**233**	**234**	**247**	**269**	**357**	**417**	**441**	**453**	**423**	**377**	**266**	**250**

Table 9: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2026 under Alternative Program Design

Load Impacts (MW) of DR Resource	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Base Interruptible Program (BIP)	216	216	228	249	261	270	260	261	268	256	242	225
Capacity Bidding Program (CBP)	0	0	0	0	39	56	92	108	74	83	0	0
SmartAC	0	0	0	0	10	20	20	18	16	6	0	0
Automated Response Technology (ART)	26	26	27	28	60	89	90	88	83	50	33	33
Total	**242**	**242**	**255**	**277**	**370**	**435**	**462**	**475**	**441**	**395**	**275**	**258**

Table 10: Portfolio-adjusted Monthly Ex Ante Load Impacts under PG&E Peaking Conditions and 1-in-2 Weather for 2027 under Alternative Program Design

Load Impacts (MW) of DR Resource	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Base Interruptible Program (BIP)	216	216	228	249	261	270	260	261	268	256	242	225
Capacity Bidding Program (CBP)	0	0	0	0	43	62	101	119	82	92	0	0
SmartAC	0	0	0	0	9	18	18	17	14	5	0	0
Automated Response Technology (ART)	34	35	35	36	71	103	104	102	96	60	41	42
Total	**250**	**251**	**263**	**285**	**384**	**453**	**483**	**499**	**460**	**413**	**283**	**267**

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CHAPTER 8

PROPOSED AND ALTERNATIVE DEMAND RESPONSE BUDGET REQUEST

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PROPOSED AND ALTERNATIVE DEMAND RESPONSE BUDGET REQUEST

A. Introduction

Pacific Gas and Electric Company (PG&E) is committed to doing the work described in this application affordably. PG&E requests $791 million for the 2024-2027 funding cycle, which is approximately $198 million per year. However, these figures alone are insufficient for purposes of comparison to the 2018-2022, a 5-year funding cycle. When 2023 is included, the budget request for the entire 2023-2027 application is $861 million, or $172 million per year. By comparison, in Decision (D.) 17-12-003 the California Public Utilities Commission (Commission) approved a total of $333 million for the 2018-2022 DR funding cycle, or $67 million per year. The budget proposed for 2023-2027 is about $528 million more in total, or $106 million more per year compared to the authorized annual budget for the 2018-2022 cycle, and a total increase in portfolio costs of 158 percent.

The $172 million annual request for 2023-2027 is greater than the $80 million authorized annually for Demand Response (DR) Expenditure Balancing Account (DREBA) over 2018-2022 as directed by the Commission in D.17-12-003, D.21-03-056, and D.21-12-015. This increase is primarily due to the continued implementation of the Emergency Load Reduction Program (ELRP) pilot mandated in D.21-03-056 and D.21-12-015, and proposed extension through 2027 (as described in Exhibit (PG&E-2), Chapter 4, Section C.2). Secondary drivers are costs associated with the implementation of Base Interruptible Program (BIP) changes approved in D.21-12-015, and new proposals in this application one of which includes the Automated Response Technology (ART) program as described in Exhibit (PG&E-2), Chapter 3. Increases in DR portfolio support costs, primarily an increase in Information Technology (IT) system and contractor costs associated with Load Management Support (as described in Exhibit (PG&E-2), Chapter 4, Section D), DR Operations and Rule 24 Operations and Maintenance (O&M) (as described in

Exhibit (PG&E-2), Chapter 6, Sections B and C, respectively), are the third major drivers.

B. Budget Development

1. Fixed and Variable Costs

PG&E’s application requests to recover funds to pay for anticipated administrative and incentive costs associated with PG&E’s programs. Administrative costs include all costs other than incentives, such as Marketing, Education, and Outreach (ME&O), pilot proposals, DR operational costs, systems & support costs, Measurement and Evaluation (M&E), program management (internal labor and third-party contracts), and overhead costs.

Some Administrative costs are fixed costs that are not a function of the activity level of the business within the relevant period. Examples of these include: overhead expenses such as facilities charges, IT system costs and software license fees, equipment costs; and general and administrative expenses, such as contracts with third parties.

Some Administrative costs are variable costs that are a function of the activity level of, or participation in, a DR program (e.g., event notifications, and metering and billing).

Incentive costs are all variable costs that fluctuate along with enrollments and/or participation in events. Proposed incentive expenditures were developed based on current and projected customer enrollment and the proposed incentive rate per kilowatt or customer. Due to the variable nature of incentives, PG&E requests that the 2023-2027 incentive costs be subject to two-way balancing account treatment, as they were in the 2018-2022 funding cycle.

PG&E’s proposed 2023-2027 DR budget request contains only expense; no capital costs are requested in this application.

2. Bottom-Up and Top-Down Approaches

PG&E used a combination of bottom-up and top-down budgeting to derive its 2023-2027 DR budget proposal. A bottom-up approach was used to forecast most program management costs, starting with the number of employees currently needed to support each area and then adjusting those numbers based on requirements and planned program changes during the 2023-2027 period. Proposed managerial and supervisory costs are based on the forecasted number of employees that will be supervised and managed within each budget sub-category.

Overhead costs are a function of the number of people working on DR and the amount of resources that they are estimated to use. These overhead expenses are litigated in the General Rate Case (GRC) and include costs such as: benefits, payroll taxes, facilities charges, IT devices, materials, contracts, meals, telephone, and travel expenses. In addition, labor cost escalation was applied using labor escalation rates from the International Brotherhood of Electrical Workers union contract effective January 1, 2016, and then extended, as is standard PG&E practice for cost estimation.

Benefit burdens are embedded in the budget request; however, the actual value of benefits is litigated in the GRC. Since a decision is still pending on PG&E's 2023 GRC Phase I application, the benefit burdens associated with labor related to PG&E's DR efforts may need to be adjusted.

A top-down approach was used in cases where the historical costs are the best indicator of future costs. For example, the Optional Binding Mandatory Curtailment Program (OBMC) and Scheduled Load Reduction Plan (SLRP) programs are not open to new enrollment and the annual cost to operate the program is expected to be close to actual costs at the end of the 2018-2022 period. A top-down approach also was used to forecast the cost of some third-party vendor contracts due to the difficulty of forecasting exactly what activities the implementers will be conducting over the time period. For example, to operate its DR programs, PG&E relies on services provided by external vendors; however, the nature of the service needed may vary from year-to-year, therefore the costs do as well.

3. Integrated Demand-Side Management

In D.18-05-041 the Commission adopted a set of general requirements and a minimum budget allocation, to be funded out of Integrated Demand Side Management (IDSM) funds, for the utility PAs to begin to integrate delivery of energy efficiency and demand response capabilities to customers.[1] Since IDSM funds can only be authorized in the Energy Efficiency proceedings, no IDSM proposals are being made in this application.

C. Fund Shifting Flexibility

PG&E requests that the Commission modify the fund-shifting rules it approved in D.12-04-045. These rules allow PG&E the flexibility "to shift up to 50 percent of a program's funds to another program within the same budget category," without prior Commission authorization and proper monthly reporting.[2] The rules also "require Utilities to submit a Tier 2 Advice Letter [AL] before shifting more than 50 percent of a program's funds to a different program within the same budget category."[3] A Tier 3 AL must be submitted and approved before funds may be shifted between categories.[4]

PG&E seeks authority to raise the percentage of funding it may reallocate within each budget category without prior Commission authorization to 75 percent, and that it be permitted to fund shift between budget categories via the submission of a Tier 2 AL before becoming effective. Said changes will permit PG&E to quickly modify its DR programs, and stand-up enabling technology, to appropriately respond to unexpected events or changing conditions, which are at times hampered by current fund-shifting restrictions. For instance, in 2021 PG&E erected several new pilot programs—including the Power Saver Rewards/DRET study and ELRP. These efforts were complicated by the need to contract with vendors and fund IT system enhancements (well in advance of receiving formal Commission approval in D.21-03-056) in order to meet a very ambitious, Commission-mandated, roll-out schedule. PG&E could have started said work faster if additional flexibility had existed to shift funds from budget categories with surplus funds to its IT systems budget, which was projected to be overspent. Thus, additional fund-shifting flexibility allows for the

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1 D.18-05-041 contained the authorized funding for all three Investor-Owned Utilities (IOU). Specifically, it called for an IOU based load share allocation of $20 million for the commercial sector with the residential sector receiving $1 million per IOU. D.18-05-041, p. 184, Ordering Paragraph (OP) 10.

2 D.12-04-045, p. 27.

3 *Ibid*.

4 D.20-05-009, OP 2.

faster reallocation of program funds to activities with the highest value and/or greatest participation potential.

1. Year-to-Year Carryover Flexibility

PG&E proposes to retain the existing ability to carry unspent funds within each budget category from one year into subsequent years.

2. Program Modifications and New Programs Within Overall Funding Limit

As described in Exhibit (PG&E-2), Chapter 2, Section G, PG&E also seeks flexibility to modify its 2024-2027 DR program design elements (e.g., incentive and penalty structure, event durations, etc.) to reflect updated information and analyses regarding the relative costs and benefits of the programs to customers. Changes to programs after the Commission's decision in this proceeding would be proposed via a voluntary submission of a Tier 1 or 2 AL by December 1 of each year in the funding period. PG&E proposes that the program adjustments would need to become effective by May 1 of the following year.

D. Comparison Between 2018-2022 Approved Budget and 2023-2027 Proposed Budget

As described above, PG&E requests $861 million for the 2023-2027 funding cycle, or $172 million per year. This is $106 million per year more than was authorized for the 2018-2022 funding period, and a total increase in portfolio costs of 158 percent.

TABLE 8-1
COMPARISON BUDGET TABLE
(THOUSANDS OF DOLLARS)

Line No.	Funding Categories	2018-22 Auth.	2023 Total	2024-27 Total
1	Category 1: Supply-Side DR Programs			
2	AC Cycling: SmartAC™	$31,980	$6,396	$5,697
3	BIP	161,770	32,354	175,359
4	Capacity Bidding Program (CBP)	20,515	5,295	28,479
5	ART	N/A	N/A	$23,796
6	Category 1 Total	$214,265	$44,045	$233,331
7	Category 2: Load Modifying DR Programs			
8	OBMC/SLRP	$63	$8	$35
9	Category 2 Total	63	8	35
10	Category 3: Rule 24[(a)]			
11	Rule 24 O&M	12,931	4,210	13,916
12	Category 3 Total	$12,931	$4,210	$13,916
13	Category 4: Tech Programs			
14	AutoDR	$20,446	$ $5,411	$9,523
15	DR Emerging Technology	7,230	1,510	20,031
16	Category 4 Total	$27,677	$6,921	$29,554
17	Category 5: Pilots			
18	Supply Side Pilot	$6,337	–	–
19	Pilot A (Smart Panel)	–	–	$11,214
20	Pilot C (Agricultural)	–	–	4,786
21	Excess Supply	1,813	–	–
22	ELRP	65,000	–	425,617
23	DAC DR Pilot	1,000	–	–
24	Category 5 Total	$74,150	–	$441,617
25	Category 6: ME&O			
26	DR Core Marketing & Outreach	$12,221	$2,032	$1,938
27	SmartAC™ Market	–	–	10,726
28	Education and Training	1,350	469	2,047
29	Category 6 Total	$13,571	$2,501	$14,711

TABLE 8-1
COMPARISON BUDGET TABLE
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Funding Categories	2018-22 Auth.	2023 Total	2024-27 Total
30	Category 7: Portfolio Support			
31	DR M&E	$11,777	$2,074	$9,188
32	DR Integration Policy and Planning	8,386	1,645	7,181
33	DR Operations	33,452	8,703	33,534
34	Load Management Support	–	–	8,000
35	DR Study	2,000	–	–
36	Category 7 Total	$55,615	$12,423	$57,904
37	Total DR Portfolio	$398,271	$70,107	$791,069

(a) As described in Exhibit (PG&E-2) Chapter 5, PG&E is not seeking incremental funding for the Demand Response Auction Mechanism (DRAM) pilot at this time.

E. Comparison of Proposed to Alternative Budget Scenario for 2023-2027

As described in depth in Exhibit (PG&E-2), Chapter 9, the program proposals in Exhibit (PG&E-2), Chapter 3, Sections B, C, and D, have a TRC score below 1.0 when analyzed using the 2016 DR Cost Effective Protocols, and thus are not deemed cost effective. While not the preferred approach, PG&E developed alternative program designs and budgets, and highlighted the trade-offs resulting from adoption of these, in Exhibit (PG&E-2), Chapter 3. In this section PG&E puts forward a summary of the alternative program budget for 2024-2027.

In its alternative scenario, PG&E requests $721 million for the 2024-2027 funding cycle, which is approximately $180 million per year. However, these figures alone are insufficient for purposes of comparison to the 2018-2022, a 5-year funding cycle. When 2023 is included, the budget request for the entire 2023-2027 application is $791 million, or $158 million per year. By comparison, in D.17-12-003 the Commission approved a total of $333 million for the 2018-2022 DR funding cycle, or $67 million per year. The alternative budget request is about $458 million more in total, or $92 million more per year compared to the authorized annual budget for the 2018-2022 cycle, and a total increase in portfolio costs of 137 percent.

TABLE 8-2
ALTERNATIVE BUDGET TABLE
(THOUSANDS OF DOLLARS)

Line No.	Funding Categories	2018-22 Auth.	2023 Total	2024-27 Total
1	Category 1: Supply-Side DR Programs			
2	AC Cycling: SmartAC™	$31,980	$6,396	$5,697
3	BIP	161,770	32,354	107,595
4	CBP	$20,515	$4,892	$26,268
5	ART	N/A	N/A	$23,796
6	Category 1 Total	$214,265	$43,642	$163,357
7	Category 2: Load Modifying DR Programs			
8	OBMC/SLRP	$63	$8	$35
9	Category 2 Total	$63	$8	$35
10	Category 3: Rule 24[(a)]			
11	Rule 24 O&M	$12,931	$4,210	$13,916
12	Category 3 Total	$12,931	$4,210	$13,916
13	Category 4: Tech Programs			
14	AutoDR	$20,446	$5,411	$9,523
15	DR Emerging Technology	7,230	1,510	20,031
16	Category 4 Total	$27,677	$6,921	$29,554
17	Category 5: Pilots			
18	Supply Side Pilot	$6,337	–	–
19	Pilot A (Res Whole Home)	–	–	$11,214
20	Pilot C (Agricultural)	–	–	4,786
21	Excess Supply	1,813	–	–
22	ELRP	65,000	–	425,617
23	DAC DR Pilot	1,000	–	–
24	Category 5 Total	$74,150	–	$441,617

TABLE 8-2
ALTERNATIVE BUDGET TABLE
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Funding Categories	2018-22 Auth.	2023 Total	2024-27 Total
25	Category 6: ME&O			
26	DR Core Marketing & Outreach	$12,221	$2,032	$1,938
27	SmartAC™ Market	–	–	10,726
28	Education and Training	1,350	469	2,047
29	Category 6 Total	$13,571	$2,501	$14,711
30	Category 7: Portfolio Support			
31	DR M&E	$11,777	$2,074	$9,188
32	DR Integration Policy and Planning	8,386	1,645	7,181
33	DR Operations	33,452	8,703	33,534
34	Load Management Support	–	–	8,000
35	DR Study	2,000	–	–
36	Category 7 Total	$55,615	$12,423	$57,904
37	Total DR Portfolio	$398,271	$69,705	$721,094

(a) As described in Exhibit (PG&E-2) Chapter 5, PG&E is not seeking incremental funding for the DRAM pilot at this time.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
COST EFFECTIVENESS EVALUATION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
COST EFFECTIVENESS EVALUATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
COST EFFECTIVENESS EVALUATION

A. Cost Effectiveness Analysis Overview

1. Summary

Per Decision (D.) 16-09-056 (Guidance Decision), Pacific Gas and Electric Company (PG&E or the Utility) presents its required Cost Effectiveness (CE) analysis for its proposed 2024-2027 Demand Response (DR) portfolio. PG&E performed CE analyses for each DR program individually and for its total portfolio using the 2016 DR CE Protocols (2016 Protocols).[1,2]

Under the 2016 Protocols, PG&E reports its DR CE results—both for individual DR programs and for the entire DR portfolio—using the California Public Utilities Commission's (CPUC or Commission) Standard Practice Manual (SPM).[3]

1) The SPM includes four CE tests:
   - Total Resource Cost (TRC) Test;[4]
   - Ratepayer Impact Measure (RIM) Test;

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[1] Resolution (Res.) E-4788, July 14, 2016, and its Appendix A include the final adopted 2016 DR CE Protocols and D.15-11-042, Decision Addressing the Valuation of Load Modifying DR and DR CE Protocols, November 30, 2015. The 2016 DR CE Protocols, CPUC, DR CE (July 2016), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of Apr. 26, 2022).

[2] Pursuant to D.10-12-024 and affirmed in D.15-11-042, Critical Peak Pricing (CPP) rates, i.e., Peak Day Pricing (PDP), SmartRate™, and pilot programs are not included in the CE analysis.

[3] The CPUC's "California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects" of October 2001: <https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf> (as of April 26, 2022).

[4] D.19-05-019, p. 65, Ordering Paragraph, (OP) 1 designates the TRC as the "primary test for all Commission activities, including filings and submissions, requiring cost-effectiveness analysis of distributed energy resources, except where expressly prohibited by statute or Commission decision." D.19-05-019, pp. 65-66, OP 2 indicates filings shall also review and consider the PAC and the RIM tests.

- Program Administrator Cost (PAC) Test; and
- Participant Cost Test (PCT).

2) These four tests are based on two criteria:

- Benefit-Cost Ratio (B/C Ratio) i.e., the present value of future benefits, divided by the present value of future costs; and
- Net Present Value (NPV) i.e., the present value of future benefits, minus the present value of future costs.

Table 9-1 presents the B/C ratios using the TRC test for PG&E's DR programs and total portfolio. It is presented with and without Auto Demand Response (ADR) costs.[5,6]

TABLE 9-1
2024-2027 DR PROGRAMS BENEFIT/COST RATIO USING TRC TEST
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW

Line No.	DR Program	TRC Test Benefit Cost Ratio (Including ADR)	TRC Test Benefit Cost Ratio (Excluding ADR)
1	Automated Response Technology Program (ART)	1.57	1.56
2	Base Interruptible Program (BIP)	0.82	0.83
3	Capacity Bidding Program (CBP)	0.71	0.81
4	SmartAC™Program	0.89	0.89
5	Total DR Portfolio	0.80	0.83

The TRCs of the three legacy programs—BIP, CBP, and SmartAC™—are similar. Excluding ADR costs, their TRCs are 0.83, 0.81, and 0.89, respectively. The similarities are attributable to similar levelized annual costs. On an annual, per-kilowatt (kW) basis, BIP costs $139/kW-year to

5 D.17-12-003, p. 193, OP 27 requires that "[i]n future required cost-effectiveness analyses, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall report the Auto Demand Response costs associated with all programs that qualify for Auto Demand Response incentives and their cost-effectiveness ratios with and without the Auto Demand Response incentives…."

6 All ADR costs subject to cost-effectiveness are associated with BIP and CBP; therefore, the TRC for those two programs increases when ADR is removed from program budgets. On the other hand, when ADR is removed, the TRC for ART and SAC goes down: for ART from 1.568 to 1.559 and for SAC from 0.889 to 0.885. This is because when direct costs are removed from one program's budget, their allocation factor for indirect costs goes down, but the allocation factors for indirect costs for other programs goes up as a result of that change.

operate, CBP costs $108/kW-year, and SmartAC™ costs $133/kW-year. While CBP has the lowest annual cost of the three, CBP is a day-ahead program while BIP and SmartAC™ are day-of programs. As such, the TRC for CBP is adjusted downward by applying a factor of 0.88, the B factor, which results in a downward adjustment of TRCs for day-ahead programs. Without the B factor of 0.88, the TRC for CBP, without ADR costs, would be 0.92.

The ART Program's relatively higher cost-effectiveness value compared to PG&E's existing DR programs is driven by an incentive structure and associated administrative costs that were developed using the forward looking avoided cost. This enabled the program proposal to be at or above a TRC of 1.0. By comparison, PG&E's existing DR programs have legacy system costs and historic incentive levels, which are difficult to significantly reduce or eliminate. For instance, the direct load control infrastructure for SmartAC™ is relatively expensive to maintain. Similarly, the incentives for CBP and BIP are leveraging those adopted in the Emergency Reliability Rulemaking (R.20-11-003), which were not subject to cost-effectiveness under the applicable decisions.

Table 9-2 shows B/C ratios for the other three SPM tests for each DR program and total portfolio, excluding ADR costs.

TABLE 9-2
2024-2027 DR PROGRAMS
BENEFIT/COST RATIO BY SPM TESTS
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW, EXCLUDING ADR COSTS

Line No.	DR Program	RIM Test	PAC Test	PCT
1	ART	0.82	0.94	2.86
2	BIP	0.65	0.66	1.33
3	CBP	0.66	0.70	1.33
4	SmartAC™	0.85	0.91	2.86
5	Total DR Portfolio	0.64	0.66	1.42

Table 9-3 presents the benefits, costs, and net benefits from each program and the portfolio. A negative net benefit represents the dollar amount that would have to be removed to result in a TRC B/C ratio of exactly 1.0. Section (B)(2) of this chapter discusses PG&E's

recommendations pertaining to the outcome of the CE values presented herein.

TABLE 9-3
2024-2027 DR PROGRAMS
NPV TRC TEST BENEFITS AND COSTS
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW, EXCLUDING ADR COSTS
(MILLIONS OF DOLLARS)

Line No.	DR Program	Benefits	Costs	Net Benefits
1	ART	23.4	15.0	8.4
2	BIP	115.5	138.7	(23.2)
3	CBP	17.3	21.4	(4.1)
4	SmartAC™	6.3	7.1	(0.8)
5	Miscellaneous	–	14.8	(14.8)
6	Total DR Portfolio	162.5	197.0	(34.5)

2. Scope of Analysis

Benefits are based on forecast ex ante DR load impacts as described in Chapter 7. Costs include the DR budget request described in Chapter 8 of this application. This CE analysis includes the following DR programs:

- ART Program;
- BIP;
- CBP; and
- SmartAC™ Program.

In addition to these individual DR programs, a CE analysis is presented for PG&E's total portfolio which sums costs and benefits across the individual DR programs and includes all other miscellaneous DR costs requested in PG&E's application, e.g., Optional Binding Mandatory Curtailment Program.

Based on the direction given in D.10-12-024 and affirmed in D.15-11-042, the following items are not included in the DR CE analysis:

- Critical Peak Pricing (CPP) Programs, i.e., PDP and SmartRate™ Programs; and
- Pilot Programs.

Further, based on the 2016 Protocols,[7] Demand Response Auction Mechanism (DRAM) pilot costs and benefits are not included in this CE analysis.[8] Likewise, the cost of the Emergency Load Reduction Program is not included in the CE analysis.[9] Finally, Rule 24 Operations and Maintenance costs also are not included in the CE analysis.

3. 2016 Demand Response Cost Effectiveness Protocols and Guidance

For this CE analysis, PG&E complied with the 2016 Protocols, the Guidance Decision, D.15-11-042 (DR CE Decision) as well as previous guidance from the Commission and Energy Division staff as listed in Table 9-4 below.

TABLE 9-4
2024-2027 DR PROGRAMS
SOURCES OF DR CE GUIDANCE

Line No.	Guidance Document
1	Res.E-5150, Adopting updates to the Avoided Cost Calculator for use in demand-side distributed energy resource cost-effectiveness analysis (June 24, 2021)[(a)]
2	Res.E-5077, Adopting updates to the Avoided Cost Calculator for use in demand-side distributed energy resources cost-effectiveness analysis (June 25, 2020)[(b)]
3	D.20-04-010, 2020 Policy updates to the Avoided Cost Calculator (April 24, 2020)[(c)]
4	D.19-05-019, Adopting Cost-Effectiveness Analysis Framework Policies for all Distributed Energy Resources. (May 21, 2019)[(d)]

(a) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K955/389955728.PDF.
(b) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K084/342084398.PDF.
(c) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K734/334734544.PDF.
(d) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF.

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7 2016 DR CE Protocols, CPUC, DR CE, p. 18 (July 2016), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of April 26, 2022).

8 "Other costs and benefits listed in these protocols will not be applied or used as part of the reasonableness review of demand response that participates in the DRAM." (PG&E Advice Letter 4806-E filed March 29, 2016, 2015 DR CE Protocols, November 2015, p. 8, approved by Res. E-4788, effective July 14, 2016).

9 D.21-03-056 clarified on p. 29 that "[t]he ELRP as adopted in this decision is a pilot program;..."

4. DR Cost Effectiveness Report

To enhance both the transparency and consistency of the DR CE analysis, the Investor-Owned Utilities (IOU) are required to use a public, spreadsheet model provided by the Commission, i.e., the DR CE Report, to generate an NPV and B/C Ratio under each SPM test both for each DR program being analyzed as well as for the total portfolio.

The DR CE Report utilized: (1) inputs from Energy and Environmental Economics, Inc.'s (E3)[10] latest avoided cost model,[11] (2) was updated for the A factor calculation, and (3) updated to reflect PG&E's after-tax Weighted Average Cost of Capital to 7.1 percent.[12] Separately, the three IOUs engaged E3, the developer of the DR CE Report, to make necessary updates based on evolving modifications from the avoid cost proceedings.[13]

Per the 2016 Protocols, the DR CE Report applies various avoided cost adjustment factors, e.g., the A, B, C, D, E, F, and G factors.[14]

- A factor: The IOUs calculate their respective A factors using the results of the Renewable Energy Capacity Planning Model (RECAP), E3's public, Loss-of-Load Probability tool. Table 9-5 shows the calculated A factors for each of PG&E's DR programs.

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[10] Energy+Environmental Economics, Energy Division's consultant.

[11] Energy+Environmental Economics, Tools ACM: Avoided Cost Model, <https://www.ethree.com/tools/acm-avoided-cost-model/> (as of April 26, 2022).

[12] The after-tax average weighted cost of capital may need to be updated after the Commission issues its decision in the 2022 cost of capital proceeding (A.21-08-013, A.21-08-014, and A.21-08-015). The 2023 cost of capital proceeding A.22-04-008 was recently filed.

[13] E3 provided the utilities a summary of these updates in April 2022.

[14] Please refer to DR CE Protocols for definitions on each of the factors. CPUC, DR CE pp. 32-34 (July 2016), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of April 26, 2022).

TABLE 9-5
2024-2027 DR PROGRAMS
A FACTOR BASED ON RECAP MODEL

Line No.	DR Program	A Factor	Availability % for RECAP A Factor	Dispatchability % for RECAP A Factor
1	ART	99.5%	100.0%	99.5%
2	BIP	99.5%	100.0%	99.5%
3	CBP	93.3%	93.8%	99.5%
4	SmartAC™	99.5%	100.0%	99.5%

- B factor: Based on Table 7 in the 2016 Protocols, PG&E used 88 percent for the ART and CBP day-ahead programs and 100 percent for the BIP and SmartAC programs.
- C factor: Based on an understanding that all of PG&E's DR programs can be called at the discretion of the utility, a value of 100 percent was used for ART, BIP, CBP, and SmartAC™.
- D factor: Since PG&E's legacy DR programs were not designed to defer any specific distribution system investments, the D factor will be assumed to be the default value of zero percent, i.e., not including any avoided Transmission and Distribution benefit.
- E factor: PG&E updated its E factor to 106 percent for ART, 112 percent for BIP, 120 percent for CBP, and 117 percent for SAC. These factors represent the ratio of energy prices during the hours when each program is expected to be dispatched[15] and energy prices during the hours used by E3 to calculate its average peak energy price, which are defined by E3 to be the hours when the generation capacity prices are nonzero. This calculation is based on E3's forward projections of PG&E's Default Load Aggregation Point prices for years 2024 through 2027.
- F factor: Based on an understanding that none of PG&E's DR programs, as currently designed, would offset PG&E's procurement of flexible capacity, the F factor will be assumed to be 100 percent, i.e., having no effect on the avoided capacity benefit.

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15 The hours of day when PG&E DR programs are likely to be dispatched are 4 p.m-9 p.m. The months of year when each program is expected to be dispatched include: May through October for ART, September for BIP, July through August for CBP, and July through September for SAC.

- G factor: Because none of PG&E's DR programs are in a generation resource constrained area, as defined in the 2016 Protocols, the G factor will be assumed to be 100 percent, i.e., having no effect on the avoided capacity benefit.

To summarize, the B, C, D, E, F, and G factors used by PG&E in the DR CE Report are shown in Table 9-6.

TABLE 9-6
2024-2027 DR PROGRAMS
OTHER ADJUSTMENT FACTORS IN DR CE REPORT

Line No.	DR Program	B Factor	C Factor	D Factor	E Factor	F Factor	G Factor
1	ART Program	100%	88%	100%	106%	100%	100%
2	BIP	100%	100%	100%	112%	100%	100%
3	CBP	100%	88%	100%	120%	100%	100%
4	SmartAC™	100%	100%	100%	117%	100%	100%

Additionally, as described in Section 3.A of the 2016 Protocols, the DR CE Report allocates certain costs across DR programs in cases where such costs cannot be directly assigned to a specific program. These costs include: (1) AutoDR, (2) Evaluation, Measurement and Verification (EM&V), (3) Marketing, Education and Outreach (ME&O), and (4) Systems Support. Per the 2016 Protocols, costs that were not directly assigned were allocated proportionally to DR program budgets. Table 9-7 illustrates this allocation.

TABLE 9-7
2024-2027 DR PROGRAMS
ALLOCATION OF NON-PROGRAM-SPECIFIC COSTS TO DR PROGRAMS

Line No.	DR Program	Category 4: ADR	Category 6: ME&O	Category 7: EM&V	Category 7: Sys. Support
1	ART Program	0%	0%	9%	9%
2	BIP	40%	29%	15%	69%
3	CBP	35%	7%	15%	11%
4	SmartAC™	0%	8%	9%	3%
5	Portfolio	0%	47%	50%	8%
6	Not in CE Analysis[a]	25%	9%	2%	0%
7	Total	100%	100%	100%	100%

5. Demand Response Cost Effectiveness Under Alternative Scenarios

As detailed in Exhibit (PG&E-2), Chapter 3, PG&E has evaluated its DR program operating assumptions and proposals for 2024-2027 and prepared an alternative operating plan for each of its programs that would yield a cost-effective or nearly cost-effective evaluation of each program's costs and benefits.[16]

- BIP can achieve a TRC of 1.05, excluding ADR costs, if PG&E not only foregoes its proposed incentive increases for 2024-2027, but also unwinds the incentive increases that were adopted in the Emergency Reliability Order Instituting Rulemaking (OIR) Phase 1 and 2 Decisions for purposes of analysis.[17]
- CBP can achieve a TRC of 0.87, excluding ADR costs, through a modification of the program design to extend the minimum participation option to 5 hours from 4 hours, and to increase the window of program availability to 11 PM. Additionally, the alternative CBP proposal foregoes the incentive increases proposed in this application.
- SmartAC™ does not have an alternative proposal.
- ART is cost effective and therefore offers no alternative proposal.

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16 All ADR costs subject to cost-effectiveness are associated with BIP and CBP; therefore, TRC for those two programs increases when ADR is removed from program budgets. On the other hand, when ADR is removed, the TRC for ART and SAC goes down: for ART from 1.468 to 1.452 and for SAC from 0.854 to 0.849. This is because when direct costs are removed from one program's budget, their allocation factor for indirect costs goes down, but the allocation factors for indirect costs for other programs goes up as a result of that change.

17 D.21-03-056 and D.21-12-015.

TABLE 9-8
2024-2027 DR PROGRAMS
TRC AND NET BENEFITS UNDER ALTERNATIVE OPERATING SCENARIO
EXCLUDING ADR COSTS

Line No.	DR Program	TRC Test Benefit Cost Ratio (Including ADR)	TRC Test Benefit Cost Ratio (Excluding ADR)
1	ART	1.47	1.45
2	BIP	1.02	1.05
3	CBP	0.78	0.87
4	SmartAC™	0.85	0.85
5	Total DR Portfolio	0.92	0.95

B. Qualitative Analysis of Social, Utility, Participant, and Market Non-Energy and Non-Monetary Benefits or Costs

1. Background

a. Requirement

As required by the 2016 Protocols, PG&E is providing a discussion of qualitative social, utility, participant, and market non-energy or non-monetary benefits or costs.

The 2016 Protocols define qualitative analysis as a descriptive analysis of the possible impact of a non-energy or non-monetary benefit or cost.[18] For example, it could include a qualitative description of variation in the benefit or cost based on location, customer class, or any other significant factor. In addition, the qualitative discussion may reference relevant research. As specified in the 2016 Protocols, this qualitative analysis covers four categories:

- Social non-energy benefits and costs;
- Utility non-energy benefits and costs;
- Participant non-energy benefits and costs; and
- Market non-energy benefits and costs.

[18] 2016 DR CE Protocols, CPUC, DR CE, p.17 (July 2016), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of April 26, 2022).

b. Qualitative Analysis Conclusions

1) These non-energy and non-monetary qualitative benefits or costs are not quantified and are not included in the DR CE Report.

2) PG&E believes that utility customer funding for DR programs should be based on avoided energy-related costs or avoided monetary costs only.

3) If CE screening for DR were to use non-energy and/or non-monetary benefits or costs, then utility customer rates will be unduly burdened with costs for which they do not receive offsetting benefits.

4) PG&E acknowledges that externality benefits exist, but these should only be used for informational purposes and not to set program funding targets or budgets. The inclusion of such values in a Societal Cost Test has potentially broad implications, and it is critical that a broad proceeding, such as the Integrated of Distributed Energy Resources (IDER) and Integrated Resource Plan (IRP) proceedings, or their successors, be used to conduct a thorough analysis and record to vet the valuation of societal costs and benefits.

c. Analysis

PG&E has analyzed non-energy and non-monetary qualitative benefits in multiple proceedings over several years. In response, PG&E provides its assessment of each of the four categories of qualitative benefits and costs in Chapter 9, Attachment A.

2. Reassessment of Cost Effectiveness Methodology

PG&E recommends that the Commission reassess how it considers CE when assessing DR programs and budgets. Currently, DR programs are required to undergo a CE assessment under the 2016 DR CE Protocols.[19] However, these protocols have not been updated since 2016 despite

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[19] 2016 DR CE Protocols, CPUC, DR CE, p. 7 (July 2016), <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of April 22, 2022).

continual updates to the ACC, which has created a divergence in measuring CE.[20]

Furthermore, since the 2016 DR Protocols, the proxy for comparing the cost and benefits associated with DR programs has transitioned from a Combustion Turbine (CT)[21] to energy storage (e.g., batteries).[22] This is notable as the net cost profile of energy storage is different from a CT, which impacts the CE of DR especially on a forward going basis.[23] This is partly due to decreases in avoided costs in the last few years with significant downward movement in future projections.[24] The result is a commensurate lowering of the CE of DR.

The challenges associated with developing cost-effective DR portfolio have been further exacerbated by the emergent need of ensuring adequate capacity for summer reliability. The Commission and the State have led with a host of DR related measures where CE has taken a lesser priority than ensuring adequate available capacity. Specifically, an Administrative Law Judge (ALJ) Ruling within the Emergency Reliability OIR (R.20-11-003) asked parties the question whether cost-effective analyses and requirements should be waived given the acute reliability needs.[25] Ultimately, the Phase 1 Decision of the Emergency Reliability Rulemaking

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20 D.16-06-007 adopted annual updates to the ACC, and D.19-05-019 adopted a schedule for both major and minor changes to the ACC, with minor changes occurring in odd-numbered years by Staff-initiated Resolution.

21 2016 DR CE Protocols, CPUC, DR CE, p. 8 (July 2016), https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness> (as of April 26, 2022).

22 CPUC Res.E-5077 (June 30, 2020), p. 6.

23 Batteries are more expensive in the short-term, but their installation costs are projected to decline over time compared with a CT, while their market revenues are substantially greater than those of a CT, resulting in a lower net cost.

24 The five-year average avoided cost from the 2018-2022 period to the 2023-2027 period has decreased by 25 percent.

25 R.20-11-003 ALJ's Ruling introducing a staff report and questions to the record and seeking responses from parties in opening and reply testimonies (December 18, 2020), Attachment 1, p. 8, Q-13.

waived CE for all DR proposals for 2021-2022,[26] which was extended to 2023 by the Phase 2 Decision.[27]

The Emergency Load Reduction Program—as directed in D.21-03-056—was ultimately waived from CE given the pilot status of the Emergency Load Reduction Program (ELRP). Similarly, the California State Emergency Program—as directed by a Governor's Proclamation[28]—demonstrates similar efforts where expeditious implementation of a DR program was prioritized by the State over any measures which involved CE.

PG&E notes that certain enhancements to its DR portfolio through the Emergency Reliability Rulemaking are being extended into the 2024-2027 period, which creates a downward pressure on CE.[29] Overall, as discussed in Exhibit (PG&E-2), Chapter 1, Section (C)(3), PG&E supports a review and potential update to the DR 2016 Protocols along with a broader assessment of how DR programs are impacted by avoided cost projections.

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26 D.21-03-056, p. 68, Finding of Fact 35.

27 D.21-12-015, p. 63.

28 Proclamation of a State of Emergency, (July 30, 2021), <https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf> (as of April 26, 2022).

29 For instance, the Phase 1 and Phase 2 Emergency Reliability Rulemaking decisions adopted higher incentive levels for BIP, which PG&E is carrying over into the 2024-2027 period. Moreover, the BIP reliability cap was raised to 3 percent for the duration of the ELRP, which was set to end in 2025 unless extended.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ATTACHMENT A

QUALITATIVE ANALYSIS

PG&E's 2024 – 2027 DR Testimony

Attachment 9A

Supports Chapter 9 (Cost-Effectiveness)

1. Social Non-Energy Benefits or Costs

Since the 2016 Protocols were developed, the CPUC has undertaken considerable effort in the IDER and IRP proceedings to develop a framework to evaluate societal costs and benefits that can be applied across all resources, both demand and supply. PG&E maintains that these are the appropriate venues to address issues of scoping the appropriate categories and values for societal costs and benefits and does not recommend quantification of values in this application.

In its initial report on developing a consistent Societal Cost Test (SCT) in 2017, the Commission discussed the policy rationale for including societal benefits in its decision-making. The intent was and is to clearly and explicitly value those benefits of Commission DER policies and programs consistent with California energy policy.[1] The Commission noted the sheer volume of possible values is daunting, so the Commission chose to focus on only those values mandated by California policy.[2] Further, the Commission recognized the asymmetry between societal costs (borne entirely by ratepayers) and societal benefits (accruing to ratepayers and society at large).[3]

Because of this complexity, the Commission chose to take a gradual approach by quantifying, and ultimately adopting, a three-part societal cost test to be tested in the IRP proceeding.[4] These three elements are: 1) a societal discount rate, 2) a social cost of carbon (SCC) in place of the adopted GHG

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1 See, ALJ Hymes' February 9, 2017 Ruling Taking Comment on Staff Proposal Recommending a Societal Cost Test, Attachment A: Distributed Energy Resources Cost Effectiveness Evaluation: Societal Test, Greenhouse Gas Adder, and Greenhouse Gas Co-Benefits, An Energy Division Staff Proposal, p. 2. January, 2017.

2 *Ibid*., p. 2.

3 *Ibid*., p. 6.

4 D.19-05-019, OP 4-7.

Adder in the ACC, and 3) air quality co-benefits. In adopting this test, the Commission stressed the importance of having a common resource valuation method so that these societal benefits could be applied with an even hand to all resource types, thus ensuring a least-cost pathway to meeting California's energy policy goals.[5]

The Commission has recently made progress towards completing this work by releasing a Societal Cost Test Impact Analysis in the IDER and IRP dockets.[6] Parties were not given an opportunity to formally comment on this analysis. However the Commission has indicated this will be scoped into the IDER proceeding, or its successor, eventually.

2. Utility Non-Energy Benefits or Costs

Utility non-energy benefits or costs, as described in the 2016 Protocols, may include indirect changes in costs as a result of DR programs such as fewer customer calls to service centers and improved customer relations. The 2016 Protocols list other utility non-energy benefits or costs as follows:

- Any changes in the number of complaint calls or service requests to the Load Serving Entities (LSE);
- Changes in the number of delinquent bills or disconnections;
- Changes in marketing and administrative costs due to DR customer participation in multiple DERs;
- Changes in customer perception or relationship to its LSE or distribution utility of Community Choice Aggregation or Direct Access customer; and
- Changes in billing costs of the LSE.

Developing third-party aggregator capabilities: Under the proposal in this application, PG&E's CBP program enables participating aggregators to enroll retail residential, commercial, industrial, and agricultural customers. CBP offers aggregators a place to participate in the California marketplace, and "provide[s] additional innovation and services to the market, yielding potential benefits to

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5 D.19-05-019, pp.29-30.

6 See "Societal Cost Test Impact Evaluation: CPUC Staff Report on the Impact of a Societal Cost Test on Resource Procurement", January 2022. https://www.ethree.com/wp-content/uploads/2022/01/CPUC-SCT-Report-FINAL.pdf

DR in California." CBP also provides opportunities for aggregators who do not have a DRAM contract, or do not want to place all their DR customers in DRAM at a given point in time, to participate in PG&E's DR portfolio. Finally, CBP maintains aggregator participation in California at a time when it is important to continue developing third-party participation.

3. Participant Non-Energy Benefits or Costs

Participant non-energy benefits or costs, as described in the 2016 Protocols, include factors such as improved ability to manage energy use and protect the environment. The 2016 Protocols list other participant non-energy benefits or costs as follows:

- Being good citizens by helping to prevent outages;
- Having a better public image (for commercial enterprises);
- Participant inconvenience or discomfort;
- Number of DR calls;
- Customer participation;
- Participant transaction cost; and
- Integrated load management solutions.

Customer participation: For DR programs where participating customers cannot opt out of events, penalties apply for non-performance or inadequate performance. This helps to ensure the DR resource's reliable operation.

Consistency of offerings by the IOUs: Statewide programs encourage participation in DR by businesses with sites located in more than one IOU service area.

4. Market Benefits or Costs

Market non-energy benefits or costs, as described in the 2016 Protocols, include factors such as market power mitigation and market transformation benefits. The 2016 Protocols list other market non-energy benefits or costs as follows:

- Improved overall system load factors, i.e., market productivity and system efficiency;

- Uncertain DR response due to temperature sensitivity and baseline measurement;
- Improved market performance (e.g., decreasing price volatility);
- Reduced DR due to customer fatigue;
- Generation portfolio diversity;
- Increased overall system flexibility;
- Market power mitigation and price suppression;
- Incentive for development of efficient controls and end-use technologies;
- Market transformation; and
- Innovation in retail markets.

Market price mitigation: This is an effect that reduces the market price of electricity. The premise of market price mitigation is that DR will lower customers' net demand, and thus reduce the market price of electricity. The starting assumption behind this category of benefit or cost is that DR embodies some kind of market benefit or cost not already provided by the assumed displacement of marginal generation capacity costs (i.e., battery). The CPUC rejected similar claimed benefits as part of SPM tests in its cost-benefit decision, D.09-08-026. If we assume any type of generation capacity is imbued with such a benefit as price elasticity/mitigation effects, market performance benefits, reliability impacts, and hedge or insurance value, the avoided generation capacity cost benefit already in the ACC also will be imbued with these same such benefits of capacity.

Local dispatch: Local dispatch capability should provide Local RA credit, which supports local reliability. Ultimately this should be captured in the utility avoided cost, at which point it would no longer be a topic for a separate discussion.

CAISO market integration/adaptability: The CAISO enables DR resources to bid into its markets, both Day-Ahead and Real-Time. The CAISO's Reliability Demand Response Resource (RDRR) product includes the ability to bid the MW into the CAISO day-of market. The CAISO's Proxy Demand Resource (PDR) product includes the ability to bid the MW into the CAISO day-ahead market (and in some cases in the day-of market).

Flexibility and versatility for aggregator and customer: PG&E's CBP offers flexibility in monthly aggregator nominations allowing aggregators to register new DR customers and verify their load reliability prior to committing them to the showing month. This flexibility also offers customers the ability to adjust their demand response load reduction commitments monthly in response to variations in their load and reduction capability.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

COST RECOVERY AND REVENUE REQUIREMENTS

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CHAPTER 10
COST RECOVERY AND REVENUE REQUIREMENTS

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CHAPTER 10
COST RECOVERY AND REVENUE REQUIREMENTS

A. Introduction

The purpose of the chapter is to present Pacific Gas and Electric Company's (PG&E) proposal for cost recovery of operating expenses and the associated revenue requirements needed to continue operating Demand Response (DR) programs and activities for the 2024-2027 program cycle. PG&E requests authorization to recover $799.6 million revenue requirements estimated based on the program expenses to be incurred for 2024-2027 program cycle based on the base case scenario which is not cost effective. Specifically, in this chapter PG&E:

- Requests the revenue requirements based on the forecasted costs for 2024-2027 included in this application. For illustration purposes, PG&E also provides in this chapter an alternative revenue requirement for a cost-effective budget, which are fully discussed in Exhibit (PG&E-2) Chapters 3 and 9;
- Proposes to continue to include the annual revenue requirement in the Annual Electric True-Up (AET) Advice Letters through distribution rates via Distribution Revenue Adjustment Mechanism;
- Proposes to continue using Demand Response Expenditure Balancing Account (DREBA) and its existing subaccounts to track the program expenses and authorized budget; and
- Proposes to return any unspent and uncommitted funds for 2024-2027 after the program cycle ends via AET.

B. Summary of Revenue Requirement Results

Table 10-1 shows PG&E's 2024-2027 DR programs proposed revenue requirements of its base case scenario. The proposed revenue requirements presented in Table 10-1 are based on the budgeted expense summarized in Table 8-1 of Exhibit (PG&E-2) Chapter 8. Table 10-3 shows a cost-effective scenario. The proposed revenue requirement represents the proposed budget gross-up with Revenue Fees and Uncollectible (RF&U).

RF&U is approved via General Rate Case (GRC) and is updated on annual basis. The factor displayed was the approved factor for 2022. Upon approval of subsequent GRCs, the revenue requirement shall be updated accordingly with the approved factor.

PG&E has proposed in its 2023 GRC Phase I application to discontinue the re-allocation of certain employee benefit costs from Distribution to the Customer Programs balancing accounts. As part of 2014 GRC Decision, certain employee benefits that were previously allocated to Distribution and recovered in the GRC revenue requirement were reallocated to Customer Programs balancing accounts. Although this adjustment was only required for the 2014 GRC, PG&E continued to reallocate these employee benefits from Distribution to the Customer Programs balancing accounts for recovery from customers through the Public Purpose Programs proceedings. PG&E has presented the revenue requirement in the instant proceeding as in accordance with the currently adopted methodology. If the 2023 GRC Phase I proposal is approved, PG&E will exclude the benefits burden allocated to DR in accordance with final decision of 2023 GRC. For illustration purposes, the budget assuming the 2023 GRC proposal to stop allocating benefit burden out to specific programs is accepted is shown in Table 10-2.

PG&E also presents the revenue requirement based on budget that assumes cost effective programs. Table 10-3 is based on the currently adopted benefit burden methodology, and Table 10-4 is based on the proposal to stop allocating the benefit burden.

TABLE 10-1
2024-2027 DEMAND RESPONSE PROGRAM REVENUE REQUIREMENT, INCLUDING BENEFIT BURDENS – BASE CASE SCENARIO
(THOUSANDS OF DOLLARS)

Line No		2024	2025	2026	2027	Total
1	Budget include benefit burden[(a)]	$197,767	$197,767	$197,767	$197,767	$791,069
2	Benefit burden included[(b)]	$4,594	$4,594	$4,594	$4,594	$18,377
3	Budget including benefit burden	$197,767	$197,767	$197,767	$197,767	$791,069
4	RF&U at 0.010811[(c)]	$2,138	$2,138	$2,138	$2,138	$8,552
5	Revenue Requirement	$199,905	$199,905	$199,905	$199,904	$799,621

(a) Budget agreed to Exhibit (PG&E-2) Chapter 8, Table 8-1.

(b) The benefit burden represents the estimated labor for 2024-2027 budget multiped with benefit burden ratio based on 2021 actual expenditure. Refer to Chapter 10 Attachment A for a breakdown of budget by expense type.

(c) The RF&U factor represents the approved 2022 factor per AL 4512-G/6373-E.

TABLE 10-2
2024-2027 DEMAND RESPONSE PROGRAM REVENUE REQUIREMENT, EXCLUDING BENEFIT BURDEN – BASE CASE SCENARIO
(THOUSANDS OF DOLLARS)

Line No		2024	2025	2026	2027	Total
1	Budget include benefit burden[(a)]	$197,767	$197,767	$197,767	$197,767	$791,069
2	Benefit burden included[(b)]	$4,594	$4,594	$4,594	$4,594	$18,377
3	Budget excluding benefit burden	$193,173	$193,173	$193,173	$193,173	$772,692
4	RF&U at 0.010811[(c)]	$2,088	$2,088	$2,088	$2,088	$8,354
5	Revenue Requirement	$195,261	$195,261	$195,261	$195,261	$781,046

(a) Budget agreed to Exhibit (PG&E-2) Chapter 8, Table 8-1.

(b) The benefit burden represents the estimated labor for 2024-2027 budget multiped with benefit burden ratio based on 2021 actual expenditure. Refer to Chapter 10 Attachment A for a breakdown of budget by expense type.

(c) The RF&U factor represents the approved 2022 factor per AL 4512-G/6373-E.

TABLE 10-3
2024-2027 DEMAND RESPONSE PROGRAM REVENUE REQUIREMENT, INCLUDING BENEFIT BURDENS – COST EFFECTIVE SCENARIO
(THOUSANDS OF DOLLARS)

Line No		2024	2025	2026	2027	Total
1	Budget include benefit burden[(a)]	$180,274	$180,274	$180,274	$180,274	$721,094
2	Benefit burden included[(b)]	$4,594	$4,594	$4,594	$4,594	$18,377
3	Budget including benefit burden	$180,274	$180,274	$180,274	$180,274	$721,094
4	RF&U at 0.010811[(c)]	$1,949	$1,949	$1,949	$1,949	$7,796
5	Revenue Requirement	$182,222	$182,222	$182,222	$182,222	$728,890

(a) Budget agreed to Exhibit (PG&E-2) Chapter 8, Table 8-2.

(b) The benefit burden represents the estimated labor for 2024-2027 budget multiped with benefit burden ratio based on 2021 actual expenditure. Refer to Chapter 10 Attachment A for a breakdown of budget by expense type.

(c) The RF&U factor represents the approved 2022 factor per AL 4512-G/6373-E.

TABLE 10-4
2024-2027 DEMAND RESPONSE PROGRAM REVENUE REQUIREMENT, INCLUDING BENEFIT BURDENS – COST EFFECTIVE SCENARIO
(THOUSANDS OF DOLLARS)

Line No		2024	2025	2026	2027	Total
1	Budget include benefit burden[(a)]	$180,274	$180,274	$180,274	$180,274	$721,094
2	Benefit burden included[(b)]	$4,594	$4,594	$4,594	$4,594	$18,377
3	Budget excluding benefit burden	$175,679	$175,679	$175,679	$175,679	$702,717
4	RF&U at 0.010811[(c)]	$1,899	$1,899	$1,899	$1,899	$7,597
5	Revenue Requirement	$177,578	$177,578	$177,578	$177,578	$710,314

(a) Budget agreed to Exhibit (PG&E-2) Chapter 8, Table 8-2.

(b) The benefit burden represents the estimated labor for 2024-2027 budget multiped with benefit burden ratio based on 2021 actual expenditure. Refer to Chapter 10 Attachment A for a breakdown of budget by expense type.

(c) The RF&U factor represents the approved 2022 factor per AL 4512-G/6373-E.

Certain forecast expenditure related to Rule 24 meets PG&E’s capitalization policy; however, the forecast capital amounts are minimal. PG&E is proposing to recover all expenditure as expense in this application to simplify the revenue requirement request and forgoes the return on capital.

C. Cost Recovery Proposal and Balancing Accounts

PG&E proposes to continue the forecast revenue requirement approved in this proceeding in distribution rates beginning in January 1, 2024. The adopted revenue requirement will be recorded to the Distribution Revenue Adjustment Mechanism. In addition, PG&E proposes to continue to track the adopted budget and actual costs associated with the DR programs in DREBA.

1. Demand Response Expenditure Balancing Account

DREBA tracks actual DR program expenses compared to the authorized budget. It currently has five subaccounts. The requested budget in this application as shown in Table 8-1 in Exhibit (PG&E-2) Chapter 8 will be tracked in the Operations, Incentives, and Auction Mechanism subaccounts. The information for the Emergency Load Reduction Program Subaccount and Critical Peak Pricing Subaccount is provided for information purposes, but the authorization for recovery for 2023 resides in Rulemaking 20-11-003 and GRC I Applications (e.g., Application (A.) 21-06-021).

a) The Operations Subaccount, a one-way balancing account that tracks all recorded operating costs compared to the authorized forecast operating budget over the entire program funding cycle. If actual costs at the end of the program cycle are less than the authorized budget, the unspent fund will be returned to customers through the AET process.

b) The Incentives Subaccount, a two-way balancing account that ensures recovery of PG&E's actual recorded event-based incentive costs. It records the authorized event-based incentive budget and actual event-based incentive costs incurred. Programs tracked in this sub-account includes the Capacity Bidding Program and Base Interruptible Program. At the end of each year, the under- or over-spend is adjusted annually through the AET process ensuring PG&E only recovers its actual event-based incentive costs.

c) The Demand Response Auction Mechanism subaccount, a two-way balancing account that records PG&E's authorized budget compared to costs incurred, including administrative expenses and incentives, associated with these pilot programs. Disposition of the balance in this sub-account occurs through the AET process at the end of the pilot program.

d) The Emergency Load Reduction Program (ELRP) Subaccount, a one-way balancing account that records PGE's authorized budget for ELRP compared to costs incurred, including administrative expenses, incentives, and other costs associated with implementing the program as adopted in Decision (D.) 21-03-056 and D.21-12-015.[1] Disposition of any remaining balance in this sub-account is through the AET process at the end of the program.

e) The Critical Peak Pricing (CPP) Subaccount, a one-way balancing account that records PG&E's authorized budget of $2 million compared to costs, both expense and capital related costs, incurred for the program to implement the new event hours of 4:00 p.m. to 9:00 p.m. as adopted in D.21-03-056. Disposition of any remaining balance in this sub-account once all program costs have been recorded will be through the AET advice process.

2. Distribution Revenue Adjustment Mechanism

Distribution Revenue Adjustment Mechanism records and recovers PG&E's authorized distribution revenue requirements and certain other distribution-related distribution costs. This mechanism recovers a majority of PG&E's authorized distribution revenue requirements and costs. Any differences between the authorized distribution revenue requirement and total distribution revenue collected for the year is reflected in rates the following year. Each year PG&E includes the authorized revenue requirements and the recorded difference between authorized and collected revenue requirement as part of its electric rate design included in PG&E's AET process.

D. Allocation of Revenue Requirement in Customer Rates

PG&E proposes to continue recovering its authorized DR revenue requirements for 2024-2027 from all customers through distribution rates included in the Distribution Revenue Adjustment Mechanism. PG&E will use the then-current CPUC-adopted methodology for revenue allocation and rate design for these costs.[2]

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[1] D.21-03-056, pp. 86-87, Ordering Paragraph (OP) 9; D. 21-12-015, pp. 166-167, OP 21.

[2] D.21-11-016 approved the current revenue allocation and rate design methods in PG&E's 2020 GRC Phase II proceeding (A.19-11-019).

E. Unspent and Uncommitted Funds for 2024-2027 Program Cycle

PG&E will return any unspent and uncommitted funds in Operations subaccounts for the 2024-2027 funding cycle after the funding cycle ends via the AET.[3]

F. Conclusion

PG&E has shown the appropriate calculation of revenue requirement of the DR revenue requirement for 2024-2027 and that the proposed existing recovery mechanism is appropriate.

[3] The unspent funds in the Incentives Subaccount are returned via AET on an annual basis while the unspent funds in the Auction Mechanism Subaccount will be returned to customers at the end of the pilot program.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

ATTACHMENT A

BUDGET BY EXPENSE TYPE

Appendix - Chapter 10 Attachment A: Proposed Budget by Expense Type

	2023				2024-2027 Base Case Scenario				2024-2027 Cost Effective Scenario			
	Labor	Contracts	Incentive	Total	Labor	Contracts	Incentive	Total	Labor	Contracts	Incentive	Total
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
Category 1: Supply-Side DR Programs												
Base Interruptible Program (BIP)	566		31,788	32,354	2,460		172,899	175,359	2,459		105,136	107,595
Capacity Bidding Program (CBP)	539		4,756	5,295	2,351		26,128	28,479	2,351		23,917	26,268
AC Cycling: Smart AC	5,759		637	6,396	2,042	3,655		5,697	2,042	3,655		5,698
Automated Response Technology				-	4,759		19,037	23,796	4,759		19,037	23,796
Category 1 Total	6,864	-	37,181	44,045	11,612	3,655	218,064	233,331	11,612	3,655	148,090	163,357
Category 2 - Load Modifying DR Programs												
OMBC/SLRP	8			8	35			35	35			35
Category 2 Total	8	-	-	8	35	-	-	35	35	-	-	35
Category 3: Rule 24												
Rule 24 O&M	4,175	35		4,210	13,758	158		13,916	13,758	158		13,916
Category 3 Total	4,175	35	-	4,210	13,758	158	-	13,916	13,758	158	-	13,916
Category 4: Tech Programs												
AutoDR	645	1,466	3,300	5,411	761	3,663	5,100	9,524	761	3,663	5,100	9,524
DR Emerging Technology	228	1,282		1,510	2,431	17,600		20,031	2,431	17,600		20,031
IDSM - NON-RES and RES				-				-				-
Category 4 Total	873	2,748	3,300	6,921	3,192	21,263	5,100	29,555	3,192	21,263	5,100	29,555
Category 5: Pilots												
5 Pilot A (Res Whole Home)				-	3,189		8,025	11,214	3,189		8,025	11,214
5 Pilot C (Agricultural)				-	786	1,600	2,400	4,786	786	1,600	2,400	4,786
ELRP				-	18,580	31,037	376,000	425,617	18,580	31,037	376,000	425,617
Category 5 Total	-	-	-	-	22,554	32,637	386,425	441,616	22,555	32,637	386,425	441,617
Category 6: ME&O												
DR Core Marketing & Outreach	1,762	120	150	2,032	821	517	600	1,938	821	517	600	1,938
SMART AC Market				-	10,726			10,726	10,726			10,726
Education and Training	469			469	2,047			2,047	2,047			2,047
Category 6 Total	2,231	120	150	2,501	13,594	517	600	14,711	13,594	517	600	14,711
Category 7: Portfolio Support												
DR Measurement and Evaluation	949	1,125		2,074	4,088	5,100		9,188	4,088	5,100		9,188
DR Integration Policy & Planning	1,645			1,645	7,181			7,181	7,181			7,181
Demand Response Operations	5,713	2,990		8,703	24,934	8,600		33,534	24,934	8,600		33,534
Load Management Support				-	8,000			8,000	8,000			8,000
Category 7 Total	8,307	4,115	-	12,422	44,204	13,700	-	57,904	44,204	13,700	-	57,904
Grand Total	22,458	7,018	40,631	70,107	108,949	71,930	610,189	791,069	108,948	71,930	540,215	721,904

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF
ANUROOBA BALAKRISHNAN

Q 1 Please state your name and business address.

A 1 My name is Anurooba Balakrishnan, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Program Manager Senior in the Demand Response (DR) programs. I am responsible for overseeing the DR Program Capacity Bidding Program (CBP). In my role as Program Manager, I am responsible for overseeing all aspects of CBP program administration including managing the budget, coordinating the work of the CBP team for day-to-day operations, collaborating with Information Technology (IT) partners for Operations and Maintenance support, overseeing compliance, onboarding new Aggregators and CBP customers and responding to Aggregator inquiries.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor's degree in Electrical Engineering from Government Engineering College (Gujarat, India) and a Master's degree in Environmental Science and Management (Energy and Climate) from University of Santa Barbara. I have been a PG&E employee since 2020. My first position in PG&E was as a Senior Performance Analyst in Contract Management group within Electric Operations. I have been responsible for managing the DR Program CBP since December 2021. Before working in the energy industry, I worked in IT on product development and technology and process improvement programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WENDY BRUMMER

Q 1 Please state your name and business address.

A 1 My name is Wendy Brummer, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am an expert program manager in the Demand Response (DR) Department within the Clean Energy Programs group. My responsibilities encompass supporting studies, technologies and pilots and also includes the management of the Automated DR program. My duties involve working with vendors and focusing on the customer experience, along with coordinating Information Technology processes and marketing, education and outreach activities.

Q 3 Please summarize your educational and professional background.

A 3 I am educated in business management and accounting. I've managed an environmental non-profit, the conflicts database within an international legal firm, a loan service department and my own businesses. I joined Honeywell International in 2004 and managed energy efficiency programs. In 2007, I joined PG&E to manage the SmartAC™ program.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Section E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ALBERT K. CHIU

Q 1 Please state your name and business address.

A 1 My name is Albert K. Chiu, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am an expert product manager of the Energy Storage and Load Management Strategy team within the Integrated Grid Planning and Innovation Department. I manage the Demand Response Emerging Technology (DRET) Program and the Integrated Demand-Side Management (DSM) Program. I provide technical advises and support to DSM Programs that focus on technologies and designs such as Demand Response (DR), Dynamic Rate, Time-of-Use/Real-Time Pricing, Electric Vehicle, Energy Efficiency, distributed generation, Decarbonation, and Load Management activities.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor degree from San Jose State University, major in Environmental Study, focus on Energy Efficiency, Renewable Energy, and Geographical Information System. I joined PG&E in 1999, started in the Energy Efficiency Department. In 2007, I joined the DR Department, managed the Automated Demand Response (ADR) Program and eventually responsible for other DR technology programs such as Permanent Load Shifting and DRET. I serve on the Board of the Open ADR Alliance as a Treasure and participate in many Technical Advisor Groups on Distributed Energy Resource and Integrated Demand-Side Management with Department of Energy, Lawrence Berkeley National Laboratory, Stanford Linear Accelerator Lab, Electric Power Research Institution, Customer Energy Efficiency, California Energy Commission, etc.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 4, "2024-2027 Demand Response Technology Programs, Pilots and Load Management Proposal":
    - Section B.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SEBASTIEN CSAPO

Q 1 Please state your name and business address.

A 1 My name is Sebastien Csapo, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Product Manager in the Integrated Grid Planning and Innovation Group within the broader Energy Procurement organization. My role is focused on supporting Third-Party Demand Response (DR), including policy activities for the DR Auction Mechanism and other DR procurement mechanisms.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Accountancy and a Bachelor of Art degree in Economics from the University of Illinois at Urbana-Champaign; and a Master's degree in Business Administration from San Jose State University. I also earned my Certified Public Accountant credential from the state of Illinois (inactive). My work experience at PG&E covers a number of functional areas, including regulatory and policy activities for PG&E's DR programs. Prior to my career at PG&E, I worked for an agency within the United States Department of Treasury handling matters of compliance and enforcement.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 2, "Program Policy Enhancements":
    - Section H;
  - Chapter 2, Attachment A, "Retail Baseline Working Group Final Report"; and
  - Chapter 5, "Third-Party Demand Response."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOHN C. HERNANDEZ

Q 1 Please state your name and business address.

A 1 My name is John C. Hernandez, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 Within Customer Care, I am the Manager of Demand Response (DR) Optimization and Transformation. This team is responsible for developing, implementing, and operating new DR programs and pilots such as Emergency Load Reduction Program, California State Emergency Program, Virtual Power Plants. Team engages with other Customer Care programs to explore and develop integrated offerings and solution to simplify customer experience. I've been in this position for three months.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Business Administration from the University of San Francisco. I've worked for PG&E for 13 years (2007-2016; 2017-Present) working on all aspects of DR and demand side management including policy, product development, operations, and program management. I was responsible for various DR pilots and exploration of new DR services, including but not limited to, 2009 DR Participating Load – Ancillary Service Pilot, 2014-2020 Supply-side Pilot (formerly known as Intermittent Resource Management 1 and 2) and Excess Supply Pilot (load-shifting, consumption DR). I briefly left PG&E in 2016-2017 and worked for ChargePoint as a business development manager assessing new energy opportunities in the electric vehicle (EV) infrastructure space. Also worked for Olivine Inc., as a Distributed Energy Resource (DER) expert developing opportunities for clients which included Investor-Owned Utility DR and DER programs and was responsible for developing pilots leveraging new DER technologies such as EVs and energy storage.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 2, "Program Policy Enhancements":
    - Section B; and
  - Chapter 4, "2024-2027 Demand Response Technology Programs, Pilots and Load Management Proposal":
    - Sections A, C.1, D, and E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ELEANOR JAEGER

Q 1 Please state your name and business address.

A 1 My name is Eleanor Jaeger, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am an Expert Program Manager in Demand Response (DR) Operations and Programs. In this position, I manage the Base Interruptible Program (BIP) and provide support to other DR programs and initiatives.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science Degree in Environmental Economics and Policy from the University of California, Berkeley. I joined PG&E's Business Finance department in 2015, supporting the Customer Care Organization. Since 2019 I have worked as a program manager in DR where I manage the BIP and other DR initiatives. Prior to joining PG&E, I worked as a Public Utilities Regulatory Analyst for over three years in the Office of Ratepayer Advocacy at the California Public Utilities Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Section B; and
  - Chapter 4, "2024-2027 Demand Response Technology Programs, Pilots and Load Management Proposal":
    - Section C.3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AARON KENDALL

Q 1 Please state your name and business address.

A 1 My name is Aaron Kendall, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 Within the Customer Care organization, I am the Program Manager of the SmartAC™ Air Conditioner cycling load control program. I have been managing the SmartAC program since 2021.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science in Business Administration with a concentration in Entrepreneurship from San Jose State University. Prior to PG&E I started, owned, and operated Virtual Frontier which was a mobile virtual reality entertainment service serving Sonoma and Marin counties. Upon the conclusion of that venture, I joined PG&E in the summer of 2020 as an associate program manager of the SmartAC and Automated Demand Response programs. In less than a years' time I assumed the role of Program Manager of the SmartAC program.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEPHEN KUNG

Q 1 Please state your name and business address.

A 1 My name is Stephen Kung, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Product Manager in Customer Care within the Demand Response (DR) Optimization and Transformation team at PG&E. I have been a Product Manager at PG&E since April 2021 and have supported the Emergency Load Reduction Program Pilot since go-live in May of 2021.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Civil and Environmental Engineering from the California Polytechnic State University of San Luis Obispo. I joined PG&E in 2002 and have held various positions through the company. I have over 20 years of experience supporting multiple roles in the utility including Interval Revenue Metering, Information Technology, DR, and back and front office Energy Procurement activities. Prior to PG&E, I worked for 3 years at Electronic Data Services as a Systems Engineer supporting the Department of Health Services Medi-Cal account.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 4, "2024-2027 Demand Response Technology Programs, Pilots and Load Management Proposal":
    - Section C.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NANCY LEE

Q 1 Please state your name and business address.

A 1 My name is Nancy Lee, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Program Manager in Customer Care within the Demand Response (DR) Operation at PG&E. I have been a Program Manager for Permanent Load Shift – Thermal Energy Storage Program and Schedule Load Reduction Program since 2020 and have supporting the Emergency Load Reduction Program Pilot since go-live in May of 2021.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Computer Science from the California State University of Chico. I joined DR in 2008. My work experience at DR including operational support and program manager for PG&E's DR programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Section F.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF HUNG (EUNICE) LI

Q 1 Please state your name and business address.

A 1 My name is Hung (Eunice) Li, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am currently a supervisor in Energy Accounting which oversees accounting and cost recovery for electric transmission business and public purpose programs including but not limited to low-income programs, energy efficiency and demand response. I also oversee several other reporting functions for Energy Accounting which include reporting with California Public Utilities Commission on balancing accounts and reporting with Department of Water Resource for Wildfire Fund Charge remittances.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a bachelor's degree with a concentration in accounting in 2001 from the Chinese University of Hong Kong. After college, I joined Deloitte Hong Kong as auditor for 4 years. While I was an auditor in Deloitte Hong Kong, I completed and certified as public accountant with Association of Chartered Certified Accountants in United Kingdom and the certification is currently inactive. I joined PG&E in 2006 as an Accounting Analyst in the Financial Accounting team. Since then I have been taking on increasing responsibilities and different accounting areas in various accounting teams. I was promoted to Supervisor overseeing accounting area for debt, intercompany transactions, various subsidiaries and consolidation in 2010. In 2012, I moved on to Revenue Accounting. Since 2016, I moved to Energy Accounting and is responsible for responsibilities stated in Answer A2 above.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 10, "Cost Recovery and Revenue Requirements"; and
  - Chapter 10, Attachment A, "Budget by Expense Type."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NEDA OREIZY

Q 1 Please state your name and business address.

A 1 My name is Neda Oreizy, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Product Manager in the Integrated Grid Planning (IGP) and Innovation Department at PG&E. In this position, my responsibilities include developing PG&E's load management strategy. I have previously been responsible for policy development of third-party demand response (DR) in various California Public Utilities Commission proceedings and Electric Rule 24 in the Click-Through Application 18-11-015 and the policy and administration of the DR Auction Mechanism pilot.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in International Studies with concentrations in Political Science and Economics from the University of California – San Diego, La Jolla, California; and a Master of Arts degree in Energy, Resources, and the Environment and International Economics from the Johns Hopkins University Paul H. Nitze School of Advanced International Studies, Washington, District of Columbia.

I joined PG&E in 2015 in the DR Department, before moving to the IGP and Innovation Department. Prior to joining PG&E, I worked in financial, economic, and strategic consulting, including supporting the World Bank on energy access policy in rural areas.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 1, "The Landscape of Demand Response and Summary of Proposals":
    - Sections B, C.1, and C.2;

- Chapter 2, “Program Policy Enhancements”:
  - Section B.1 and C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CANDICE POTTER

Q 1 Please state your name and business address.

A 1 My name is Candice Potter, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am contracted by PG&E through my employer, Resource Innovations, Inc., to serve as the cost-effectiveness witness in this Application. I serve as a Vice President at Resource Innovations, Inc. where I lead a consulting practice area that serves electric and natural gas utilities in North America.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Mathematics and Economics from the University of California at San Diego. Also, I hold a Master's degree in Statistics, also from the University of California at San Diego. I served as regulatory analyst and regulatory advisor for 8 years at San Diego Gas and Electric Company, working in the areas of electric load research, electric rate design, electric marginal cost analysis, and demand response program measurement and evaluation. I have been consulting since 2012 at my current and predecessor firms (Freeman, Sullivan and Co. and Nexant, Inc.). My consulting practice area includes demand response and behavioral utility program impact and process evaluation, customer survey design and data collection, end-use energy consumption data collection, demand response program cost-effectiveness, and California demand response prohibited resource policy and verification.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 9, "Cost Effectiveness Evaluation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOMO THORNE

Q 1 Please state your name and business address.

A 1 My name is Jomo Thorne, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Manager of Demand Response (DR) Operations and Programs. In this role I lead a team of program managers and support staff responsible for designing, marketing, and operating PG&E's DR program portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in History from Harvard University in Cambridge, Massachusetts. I've also received a Master of Business Administration, and a Master of Public Policy from the University of Michigan. In 2008, I joined PG&E and have since held various positions of increasing responsibility, including Renewable Transactor where I negotiating renewable energy power purchase agreements with third-party developers; Manager of Renewable and Clean Energy Strategy in the run up to implementation of California's 33 percent Renewable Portfolio Standard law; Manager of Value Based Reliability via which I conducted a comprehensive review of power plant outage scheduling business processes and governance across merchant and operational lines of business, implemented broad change-management strategy, and developed a new outage valuation tool that measures the market opportunity costs associated with outages; Manager of Market Initiatives Implementation where I was charged with implementing California Independent System Operator initiatives that impact the design, policy, and operations of California's wholesale energy markets, as well as conducting all market monitoring functions; and my current role as Manager of DR Operations and Programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-1), "2023 Bridge Funding":
  - Chapter 1, "2023 Program and Pilot Proposals";
  - Chapter 3, "2023 Budget and Cost Recovery";
- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 1, "The Landscape of Demand Response and Summary of Proposals":
    - Sections A, C.3 through C.6, and D;
  - Chapter 2, "Program Policy Enhancements":
    - Sections A.2, A.3, D through G, and I;
  - Chapter 3, "2024-2027 Demand Response Programs Proposals":
    - Sections A, G, and H;
  - Chapter 6, "Demand Response Operations":
    - Sections A, B, D, and E;
  - Chapter 8, "Proposed and Alternative Demand Response Budget Request";
  - Chapter 9, "Cost Effectiveness Evaluation"; and
  - Chapter 9, Attachment A, "Qualitive Analysis."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRAD WETSTONE

Q 1 Please state your name and business address.

A 1 My name is Brad Wetstone, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am an Expert Program Manager for the Rule 24 Demand Response program within PG&E's Customer Care department. I have been in my current role for approximately four years. In my role as Program Manager, I am responsible for overseeing all aspects of Rule 24 program administration including managing the budget, coordinating the work of the Rule 24 team for day-to-day operations, collaborating with Information Technology partners for Operations and Maintenance support, overseeing compliance, onboarding new Demand Response Providers (DRP) and responding to DRP inquiries. Prior to my current role, I was a Senior Account Manager for Rule 24 for two years starting in 2016 when the Rule 24 program initially launched.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor's degree in Political Science from George Washington University and a Master of Business Administration degree from the University of San Francisco. I have been a PG&E employee since 2012. My first position was as a Senior Regulatory Analyst in the Federal Energy Regulatory Commission and California Independent System Operator Relations group within the Regulatory Affairs department. I also worked as a Generator Outage Coordinator in PG&E's Energy Procurement department. From 2008 through 2011, I worked as an Energy Resources Analyst in the Power Resource Planning department at Alameda Municipal Power where I was responsible for preparing load forecasts, validating monthly power costs, transacting Resource Adequacy, and evaluating Power Purchase Agreement prices for new contracts. Before joining

Alameda Municipal Power, I worked from 2008 to 2005 as a Utility Analyst in the Energy Division at the California Public Utilities Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-1), "2023 Bridge Funding":
  - Chapter 2, "Electric Rule 24 Activities for Third-party Demand Response"; and
- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 6, "Demand Response Operations":
    - Section C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GIL WONG

Q 1 Please state your name and business address.

A 1 My name is Gil Wong, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 245 Market Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Manager of Customer Programs Measurement and Evaluation. I lead a team of analysts managing evaluations of demand response programs, dynamic and time-of-use rates, distributed generation programs, and electric vehicle (EV) programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Economics and a Bachelor of Science degree in Statistics from University of California, Davis. In addition, I received a Master's degree in Economics from University of Washington, Seattle. Since joining PG&E in 2002, I have held various positions of increasing responsibilities, including managing PG&E's load research samples and dynamic load profiles, and conducting evaluations of customer energy programs and pilots. My research experience covers demand response, critical peak pricing, electric and gas rates, energy efficiency, distributed generation, and EVs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023-2027 Demand Response Funding Application:

- Exhibit (PG&E-2), "2024-2027 Full Proposal":
  - Chapter 7, "Load Impacts, Measurement, and Evaluation";
  - Chapter 7, Attachment A, "Portfolio Adjusted Ex Ante Impacts 2023-2027."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

LIST OF ACRONYMS

PACIFIC GAS AND ELECTRIC COMPANY
2023-2027 DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS
PREPARED TESTIMONY

APPENDIX B
LIST OF ACRONYMS

Acronym	Definition
A.	Application
ABEC	Auto-DR Business Energy Coalition
ABS	Advance Billing Solutions
AC	Assigned Commissioner
AC	Air Conditioning
AC Cycling	Air Conditioning Cycling [SmartAC™]
ACEBA	Air Conditioning Expense Balancing Account
ACR	Assigned Commissioner Ruling
ADR	Automated Demand Response
ADS	[CAISO] Automated Dispatch System
AESP	Association of Energy Services Professionals
AET	Annual Electric True-Up
AL	Advice Letter
ALJ	Administrative Law Judge
AMDC	Automated Meter Data Correction
AMI	Advanced Metering Infrastructure
AMP	Aggregator Managed Portfolio
APCR	Allowance Price Containment Reserve
API	Application Program Interface
APX	Automatic Power Exchange
AREM	Alliance for Retail Energy Markets
ART	Automated Response Technology
AS	Ancillary Services
B/C	Benefit-Cost
BAA	Balancing Authority Area
BAM	Business Account Manager
BCC	Business Customer Center
BCR	Benefit Cost Ratio
BEC (E-BEC)	Business Energy Coalition
BEV	Battery Electric Vehicle
BIP (E-BIP)	Base Interruptible Program
BPM	Business Practice Manual

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
BTM	Behind-the-Meter
BUG	Backup Generator
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAISO (ISO)	California Independent System Operator
CAL EPA	California Environmental Protection Agency
CALMAC	California Measurement Advisory Council
CARB	California Air Resources Board
CARE	California Alternate Rates for Energy
CB	Customer Baseline
CBP (E-CBP)	Capacity Bidding Program
CC&B	Customer Care and Billing System
CCA	Community Choice Aggregation
CCA	Community Choice Aggregator
CCC	Customer Credit and Collection
CDH	Cooling Degree Hours
CDWR	California Department of Water Resources
CE	Cost Effectiveness
CEC	California Energy Commission
CEE	Customer Energy Efficiency
CEESP	California Energy Efficiency Strategic Plan
CEI	Continuous Energy Improvement
CEMP	Community Energy Management Program
CERTS	Consortium for Electric Reliability Technology Solutions
CESA	California Energy Storage Alliance
CFCD	CAISO Forecast of CAISO Demand
CFL	Compact Fluorescent Lamp
CIA	Commercial, Industrial and Agricultural
CISR-DRP	Customer Information Service Request for Demand Response Providers
CLAP (Custom LAP)	Custom Load Aggregation Point
CLECA	California Large Energy Consumers Association

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
CLFP	California League of Food Processors
CLIR	Client Logic with Integrated Relay
CLR	Committed Load Reduction
COC	Cost of Capital
COE	Centers of Excellence
CPA	California Power Authority
CPA	Customer Participation Agreement
CPP (E-CPP)	Critical Peak Pricing
CPUC or Commission	California Public Utilities Commission
CR	Customized Retrofit
CRM	Customer Relations Management
CSEB	Customer Specific Energy Baseline
CSI	California Solar Initiative
CSM	Cafeteria Style Menu [now known as PeakChoice]
CT	Combustion Turbine
D.	Decision
DA	Direct Access
DACC	Direct Access Customers Coalition
DBP (E-DBP)	Demand Bidding Program
DDR	Dispatchable Demand Response
DER	Distributed Energy Resources
DG	Distributed Generation
DLAP (Default LAP)	Default Lap Aggregation Point
DLC	Direct Load Control
DP	Dynamic Pricing
DR	Demand Response
DRAM	Demand Response Auction Mechanism
DRAM	Distribution Revenue Adjustment Mechanism
DRAS	Demand Response Automation Server
DRCC	Demand Response Coordinating Committee
DRE	Demand Response Enrollment [system]
DREBA	Demand Response Expenditure Balancing Account

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
DRET	Demand Response Emerging Technologies
DRM	Demand Response Manager
DRMEC	Demand Response Measurement and Evaluation Committee
DRMS	Demand Response Management System
DRO	Demand Response Operation [Interface for SmartRate™]
DROE	Demand Response On-Line Enrollment [process]
DRP	Demand Response Provider
DR-PD	Demand Response Product Development
DRPDP	Default Residential Peak Day Pricing
DRRBA	Demand Response Revenue Balancing Account
DRRC	Demand Response Research Center
DR-RFP	Demand Response Request for Proposal
DRRP	Default Residential Rate Program
DRRS	Demand Response Registration System
DSM	Demand-Side Management
E3	Energy and Environmental Economics, Inc.
EAP	Energy Action Plan
EBEW	East Bay Energy Watch
EBS	Electric Billing Solutions
ECMS	Energy Carbon Management Software
EDS	Energy Data Service
EE	Energy Efficiency
EISA	Energy Independence Security Act of 2007
EM&V	Evaluation, Measurement, and Verification
EMS/EMCS	Energy Management Control System
ENS	Energy Not Served
EPA	Energy Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERRA	Energy Resource Recovery Account
ESA	Energy Savings Assistance
ESP	Energy Service Provider

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
ET	Emerging Technologies
ETCC	Emerging Technologies Coordinating Council
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAN	Flex Alert Network
FERC	Federal Energy Regulatory Commission
FF&U	Franchise Fees and Uncollectibles
FSL	Firm Service Level
FTE	Full-Time Employee
FYP	Flex Your Power [EE-related]
FYPN	Flex Your Power Now [DR Events]
GEP	Global Energy Partners
GHG	Greenhouse gas
GO	General Order
GRC	General Rate Case
HAN	Home Area Network
HEMS	Home Energy Management System
HVAC	Heating Ventilation and Air Conditioning
HVLC	Highly Variable Load Customer
ICCP	Intercontrol Center Communication Protocol
ID	Integration Desk
IDER	Integrated Distributed Energy Resources
IDSM	Integrated Demand Side Management
IEA	Integrated Energy Audit
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IRM2	Intermittent Renewable Management Pilot Phase 2
IRP	Integrated Resource Plan
IRR	Intermittent Renewable Resource
ISO	Independent System Operator
ISTS	Information Systems Technology Services
IT	Information Technology

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
kW	kilowatt
kWh	kilowatt-hour
LAP	Load Aggregation Point
LBNL	Lawrence Berkeley National Laboratory
LCA	Local Capacity Area
LCR	Load Control Receiver/Relay or Local Capacity Requirement
LDS	Load Data Services
LED	Light Emitting Diode
LGP	Local Government Partnership
LI	Load Impact
LIA	Large Integrated Audits
LIEE	Low Income Energy Efficiency
LMP	Locational Marginal Prices
LOLE	Loss of Load Expectation
LOLP	Loss-of-Load Probability
LSE	Load-Serving Entities
LTPP	Long-Term Procurement Proceedings or Plan
M&E	Measurement and Evaluation
M&V	Measure and Validation
MA	Morning Adjustment
MAP	Markets and Performance
MARA	My Account Re-Architecture
MDAS	Meter Data Acquisition System
MDMA	Meter Data Management Agent
MDSS	Marketing Decision Support System
ME&O	Marketing, Education, and Outreach
MEG	Meter Event Group
MFLI	Multi-Family Low Income
MIDI	Moderate Income Direct Install
MLL	Maximum Load Level
MMbtu	Million British Thermal Units
MOU	Memorandum of Understanding

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
MPR	Market Price Referent
MRTU	Market Redesign and Technology Upgrade
MRTUDR	Market Redesign and Technology Upgrade Memorandum Account Demand Response Sub Account
MRTUMA	MRTU Memorandum Account
MW	Megawatt
NAISC	North American Industry Classification System
NASA	National Aeronautics and Space Administration
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NF (E-NF)	Non-Firm Program [Terminated December 31, 2007]
Non-PL/NPL	Non-Participating Load
NOPR	Notice of Proposed Rulemaking
NPV	Net Present Value
NQC	Net Qualifying Capacity
NRNC	Non-Residential New Construction
NRR	Non-Residential Retrofit
NSHP	New Solar Homes Program
O&M	Operations and Maintenance
OAS	Otherwise Applicable Schedule
OAT	Outside Air Temperature or Otherwise Applicable Tariff
OBMC	Optional Binding Mandatory Curtailment Program
OEM	Original Equipment Manufacturer
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
OpenADR	Open Automated Demand Response
PA	Program Administrator
PA	Purchase Agreement
PAC	Program Administrator Cost test
PC (E-PC)	PeakChoice™ [Schedule E-PC]
PCT	Participant Cost Test or Participant Test
PD	Proposed Decision

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
PDM	PG&E Delivery Method
PDP	Peak Day Pricing
PDR	Proxy Demand Resource
PE	Process Evaluation
PEAK	PEAK Student Energy Actions
PeakChoice™	[Formerly known as Cafeteria Style Menu (CSM)]
PEAT	Progressive Energy Audit Tool
PEV	Plug-In Electric Vehicle
PFM	Petition for Modification
PG&E or the Company or the Utility	Pacific Gas and Electric Company
PHEV	Plug-In Hybrid Electric Vehicle
PIER	Public Interest Energy Research
PIP	Program Implementation Plan
PJM	Pennsylvania-New Jersey – Maryland Interconnection
PL	Participating Load
PLA	Participating Load Agreement
PLC	Power Line Carrier
PLMA	Peak Load Management Association
PLP	Participating Load Pilot
PLS	Permanent Load Shifting
PLS	Pressure Limiting Station
POBMC	Pilot Optional Binding Mandatory Curtailment Program
PT	Participant test
PTR	Peak Time Rebate
PV	Present Value
PY	Program Year
RA	Resource Adequacy
RAR	Resource Adequacy Requirements
RDA	Rate Data Analysis
RDC	Risk Data Control
RDRP	Reliability Demand Response Product

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
RDW	Rate Design Window
RECAP	Renewable Energy Capacity Planning
RFB	Request for Bid
RFO	Request for Offer
RFP	Request for Proposal
RIM	Ratepayer Impact Measurement [test]
RNC	Residential New Construction
RO	Results of Operation
RPS	Renewables Portfolio Standard
RTM	Requirements Traceability Matrix
RTP	Real-Time Pricing
RTUC	Real-Time Unit Commitment
RUC	Residual Unit Commitment
Rule 24	Electric Rule 24
S&S	Service and Sales
S&S	Shift and Save
SA	Service Agreement
SB	Senate Bill
SC	Scheduling Coordinator
SCADA	Supervisory Control and Data Acquisition
SCAPP	Small Customer Aggregation Pilot Program
SCE	Southern California Edison Company
SCMS	Smart Charging Management System
SDG&E	San Diego Gas & Electric Company
SEP	Smart Energy Profile
SFLI	Single Family Low Income
SGIP	Self-Generation Incentive Program
SIC	U.S. Standard Industrial Classification
SLAP (Sub-LAP)	Sub-Load Aggregation Pointc
SLRP (E-SLRP)	Scheduled Load Reduction Program
SmartAC™	Air Conditioning Direct Load Control [AC Cycling]
SmartMeter™	[Brand Name for Automated Metering Initiative (AMI)]

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
SmartRate™	Brand Name for new program, voluntary for residential and commercial CPP rate
SMB	Small and Medium Business
SMS	Short Message Service
SMU	SmartMeter™ Upgrade
SNMP	Simple Network Management Protocol
SOA	Service Oriented Architecture
SoCalGas	Southern California Gas Company
SPM	Standard Practice Model and Standard Practice Manual
SQMD	Settlement Quality Meter Data
SSN	Silver Spring Networks
SSP II	Supply Side II DR Pilot
STUC	Short-Term Unit Commitment
SUBLAP	Sublocation Aggregation Point
SVLG	Silicon Valley Leadership Group
SW	Statewide
T&D	Transmission and Distribution
TA	Technical Assistance
TCA	Transmission Control Agreement
TES	Thermal Energy Storage
TeVaR	To-Expiration-Value-at-Risk
TI	Technical Incentive
TI	Technology Incentive
TLP	Target Load Profile
TOU	Time-of-Use
TPA	Third-Party Authorization Form
TRC	Total Resource Cost [test]
TURN	The Utility Reform Network
UDC	Utility Distribution Company
UEAT	Universal Energy Audit Tool
UFR	Under-Frequency Relay
UIQ	Utility IQ

LIST OF ACRONYMS
(CONTINUED)

Acronym	Definition
UPS	Uninterrupted Power Supply
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
VCM	Vehicle Communications Module
VEE	Validation, Editing, and Estimation
VFD	Variable Frequency Drive
WECC	Western Electricity Coordinating Council
WG	Working Group
WG2	Working Group 2 Proceeding (CIA customers > 200 kW)
WG3	Working Group 3 Proceeding (residential and CIA customers < 200 kW)
WS	Water Storage
XML	Extensible Markup Language
XSP	Excess Supply DR Pilot
ZNE	Zero Net Energy